Peak Potential

Reducing energy costs and empowering consumers with load management and virtual power plants

DOER Report and Policy Recommendations

Massachusetts Department of Energy Resources

December 2025

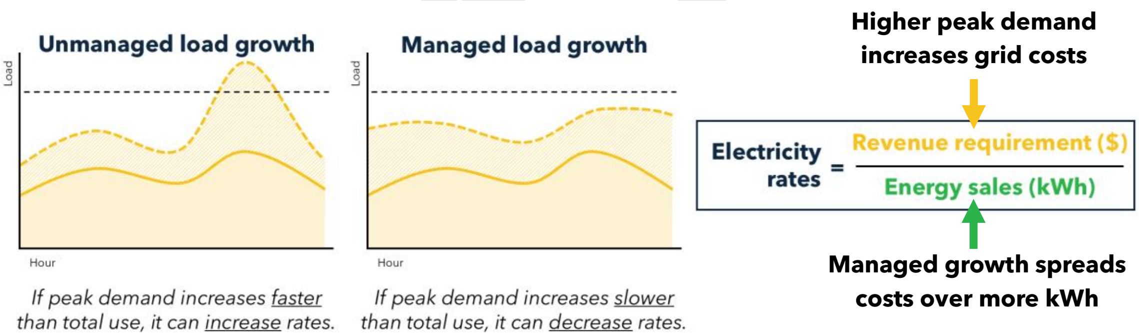
Draft (for public comment)

Executive Summary

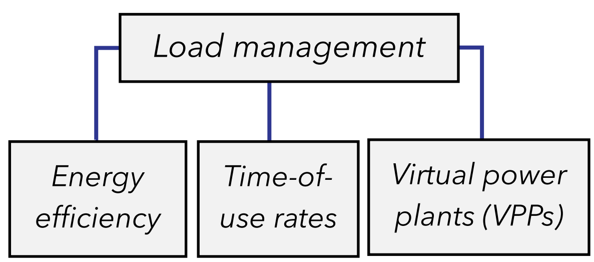
4.5 GW, $0.95 bn/yr saved	**13.8 GW, $4.8 bn/yr saved**
2030	*2050*

Peak load reduction and annual avoidable electric system costs in Massachusetts from load management tools like energy efficiency and demand flexibility.[1]

Massachusetts' ambitious climate, housing, and economic development goals will require an abundant supply of electricity. Increasing demand for electricity, particularly *peak demand*,[2] puts pressure on the electric grid, which utilities must build to handle the most extreme hours of the year. If peak demand grows faster than overall electricity use, utilities will need to build expensive infrastructure that the grid will only need for a few hours each year. Managing demand to reduce these peaks allows customers to get more mileage out of the existing grid, lowering electric rates. To grow affordably, Massachusetts must aggressively manage peak demand.



Load management refers to policies and technologies that help customers save by reducing or shifting electricity use out of peak hours. Load management includes both established tools like energy efficiency and new technologies like demand flexibility and virtual power plants (VPPs).



[1] Peak load reduction and ratepayer savings are based on the CECP scenario from the accompanying technical study, which assumes a pace of electrification in line with the CECP and substantial customer participation in flexibility. The technical study also estimates potential for a scenario with slower electrification and less aggressive adoption of flexibility. Avoided electric system cost estimates include only measures that are cost-effective on a total resource cost basis.

[2] Peak demand is the maximum amount of power that the grid must be able to deliver.

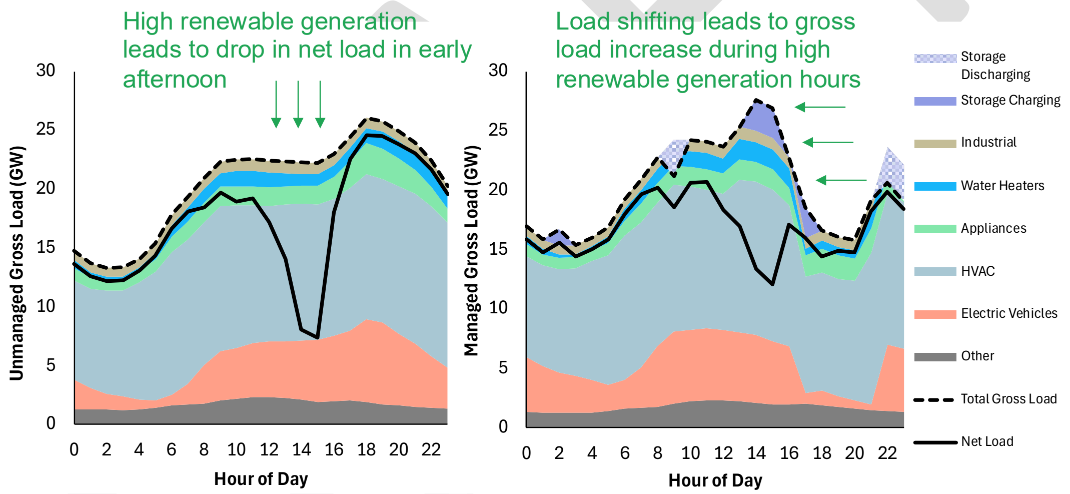
Draft (for public comment)

To quantify the potential for load management to reduce peak load and save money for customers, the Massachusetts Department of Energy Resources (DOER) commissioned Energy and Environmental Economics (E3) and the Applied Economics Clinic (AEC) to conduct the *Technical Potential of Load Management Study (Technical Potential Study)*. This report summarizes key findings and provides policy recommendations for realizing this potential to reduce energy costs for customers.

Finding 1: *Massachusetts' leading Mass Save energy efficiency program has already reduced peak loads by 1 GW, and there is 3.5 GW of total potential in 2030 and 9.5 GW in 2050 from building energy codes, retrofits, and next-generation heat pumps.*[3]

As Massachusetts continues to electrify heating and transportation, demand for winter heating will increasingly drive peak load, just as summer cooling demand drives the peak today. Energy efficiency – measures like building insulation and weatherization – is the first line of defense against peak loads in both summer and winter.[4]

Figure 1: Unmanaged (left) and managed (right) loads on a peak winter day in 2050.[5]



Finding 2: *Electric vehicle (EV) load management, through both managed charging programs and vehicle-to-everything (V2X),*[6] *is a no-regrets, high-potential strategy that could provide 300 MW of capacity in the near term and 6.5 GW in the long term. Transitioning to default TOU rates will also encourage EV load management.*

[3] Prior 1 GW reduction is based on ISO-NE's CELT energy efficiency forecast.
[4] *Passive* load management refers to measures that reduce energy demand in all hours of the year, while *active* load management refers to measures that reduce demand during specific hours.
[5] E3, "Evaluating Load Management Strategies for a Net-Zero Grid" at 36.
[6] V2X refers to technologies that allow an EV to discharge its battery to provide power either to the grid (vehicle-to-grid), to a household (vehicle-to-home), or to individual appliances (vehicle-to-load).

Massachusetts already has 140,000 EVs on the road today and a goal of 900,000 by 2030.[7] If unmanaged, EV charging could significantly increase peak demand on the grid. Managed charging can provide consistent, reliable peak reductions by delaying charging to off-peak hours while ensuring that cars are fully charged when needed. This creates opportunities for substantial savings in the next five years: EV load management, either utility-run programs, TOU rates, and V2X, can help Massachusetts customers save and reduce long-term grid infrastructure needs.

Finding 3: *Massachusetts' ConnectedSolutions program is a successful VPP that combines batteries, central air conditioning (AC), and flexible commercial loads to reduce peak demand. Expanding VPPs to categories like water heaters and other home appliances can unlock nearly 1 GW of untapped potential. Technology-neutral incentives like TOU rates and whole-home demand response can expand access.*

The Technical Potential Study shows that flexible devices like water heaters and household appliances can help reduce peak load, but these devices are not currently eligible for ConnectedSolutions, Massachusetts' flagship VPP. Once Massachusetts utilities have deployed smart meters, they can expand access to load flexibility by evolving towards technology-neutral incentives (like TOU rates and whole-home or behavioral demand response) rather than technology-specific programs. These incentives reward customers for reducing peak load without restriction on how they achieve that reduction. Unlike current programs, technology-neutral incentives would not require customers to buy smart home devices (e.g. smart thermostats), lowering barriers for renters and low-income customers to participate in load management.

Finding 4: *Barriers like the need for smart devices make it difficult for renters, low-income customers, and environmental justice (EJ) communities to participate in existing programs. Reducing the need for up-front investment and avoiding shifting costs to non-participants can help ensure equitable distribution of costs and benefits.*

Low-income and EJ communities bear a disproportionate burden from both high energy costs and the power plants needed to meet peak demand. Feedback from community advocates and EJ stakeholders emphasizes the need for equitable access to load management programs for renters, low-income, and EJ customers. For example, the need to buy a smart thermostat to participate in existing programs creates a barrier for renters or customers who cannot justify this up-front cost. Technology-neutral incentives (as discussed in Finding 3) and policies that provide support for customers facing high upfront costs can help reduce this barrier.

[7] Current deployment as of 2024 (Clean Energy and Climate Metrics). Target Based on CECP modeling.

To ensure that all ratepayers share equitably in the costs and benefits of load management, incentives should not exceed the benefits that customers provide to the grid. While it is important to reward customers who reduce their peak demand, incentives that are too high can shift costs onto non-participating customers.

Finding 5: *Innovative technologies and models like load aggregation and orchestration through VPPs can maximize the benefits of load management while reducing the risk of creating secondary local peaks on the distribution grid.*

If not carefully designed, load management programs can have unintended consequences; for example, if all EVs in a neighborhood begin charging at the start of an off-peak window. Policymakers, regulators, and utilities should work closely with OEMs and VPP providers to ensure that load management programs maximize benefits while avoiding negative impacts on the distribution grid.

Policy recommendations: *To realize these benefits, Massachusetts will need to evolve its approach to load management to aggressively expand capacity, ensure equitable access, and support innovation to unlock this potential, as outlined in Table 1.*

Table 1: Summary of recommendations

Principle 1: Sustain Massachusetts' lead on energy efficiency by continuing to invest in building energy retrofits and efficient new construction.
New Buildings: support expansion of stretch and specialized codes. Accelerate the construction of efficient new buildings.
Existing Buildings: continue to invest in retrofits for existing buildings and explore opportunities for deep energy retrofits in grid-constrained regions.
Large Buildings: diagnose bottlenecks in load management adoption for large buildings using energy reporting data.
Ground-source heat pumps (GSHP): evaluate opportunities for up-front incentives and workforce development to support GSHP deployment, especially in constrained regions of the grid.
Principle 2: Scale EV load management as a no-regrets strategy for reducing peak load. Invest in active managed charging and V2X to maximize benefits and minimize grid impacts.
Managed charging: scale up residential EV managed charging programs. Develop managed charging programs for commercial customers.
V2X: develop interconnection policies, interoperability standards, and incentives.
Active EV management: use active managed charging and grid-aware V2X dispatch to maximize benefits and minimize negative grid impacts.

Principle 3: Pay customers for supporting the grid with easy-to-use, low-friction incentives like TOU rates and technology-neutral demand response.

Electric rates: develop a default seasonal TOU rate for residential and small commercial customers.

Peak pricing: explore technology-neutral incentives like critical peak pricing, whole-home demand response, and other advanced rate designs.

Principle 4: Support innovation in customer-centric aggregation, particularly through municipal aggregations, to develop new load management technologies and products.

Residential VPPs: scale technology-neutral demand response pilots in the 2025–2027 energy efficiency plan to full-scale programs in future years.

VPP-ready equipment: Investigate standards or market development policies to support adoption of flexible appliances.

Customer-centric innovation: support technology and business model innovation to reduce supply costs for customers (e.g., bundling load management with municipal aggregation supply contracts).

Retail/wholesale coordination: Increase coordination of retail demand response with wholesale markets, explore options to participate in ISO-NE markets.

Principle 5: Ensure equitable access and distribution of benefits by minimizing cost shift from load management programs, reducing barriers to access and DER ownership for renters and low-income customers, and focused outreach.

Avoid cost shift: avoid shifting costs to non-participants by calculating compensation for load management based on benefits provided to the grid.

Address barriers to participation: develop technology-neutral incentives where customers can participate without expensive equipment like smart appliances. Engage communities with outreach to educate customers on load management options and receive feedback on program design.

Support DER ownership: investigate up-front incentives to support measures like home energy retrofits and storage that reduce energy burden, provide health and resiliency benefits, and help households build wealth.

Principle 6: Align utility business models with load management through appropriate incentive mechanisms and regulatory frameworks.

Incentive mechanisms: investigate utility incentive mechanisms that balance electrification with managed load growth (e.g. system utilization incentives).

Integrated planning: improve the use of load management in utility planning (e.g. through integrated distribution system planning).

Regulatory sandbox: provide a constructive regulatory environment for utilities to experiment with new load management tools.

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Acronyms

AC	Air conditioning
AEC	Applied Economics Clinic
AMI	Advanced metering infrastructure
ASHP	Air source heat pumps
BTM	Behind the meter
C&I	Commercial & industrial
CECP	Clean Energy and Climate Plan
CPP	Critical peak pricing
CVEO	Cape and Vineyard Electrification Offering
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DOER	Department of Energy Resources
DPU	Department of Public Utilities
DRR	Demand Response Resource
E3	Energy and Environmental Economics
EJ	Environmental justice
ESMP	Electric Sector Modernization Plan
EV	Electric vehicle
FI	Flexible interconnection
GSHP	Ground source heat pump
GW	Gigawatt
HVAC	Heating, ventilation, and air conditioning
IDSP	Integrated distribution system planning
ISO-NE	Independent System Operator New England
LMI	Low- and moderate-income
MassCEC	Massachusetts Clean Energy Center
MW	Megawatt
NWA	Non-wires alternative
PIM	Performance incentive mechanism
TOU	Time-of-use
V2X	Vehicle-to-everything
VPPs	Virtual power plant

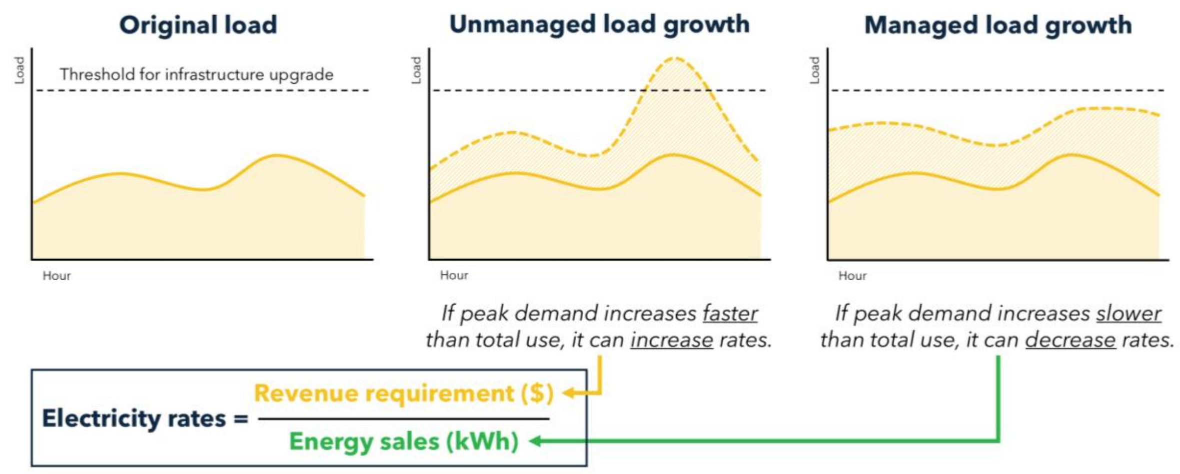
1 Introduction

Massachusetts' ambitious climate, housing, and economic development goals will require an abundant supply of electricity. Meeting this demand growth will require investment in all parts of the electric power system, including generation, the high-voltage transmission grid, and the local distribution grid. Because the power system is built to handle *peak demand*, the most extreme hours of the year, the cost of future grid investments depends largely on whether new load adds to the peak.

Without action, unmanaged load growth will add to the peak, requiring new grid investments (on top of expected necessary investments) to serve a small number of extreme hours each year. The cost of these investments will end up on customer bills in the form of increased rates. ISO New England's *2050 Transmission Study* illustrates this reality: each additional gigawatt of peak demand in 2050 leads to $1.5 billion in extra costs for transmission alone. To avoid the most substantial transmission costs, ISO-NE estimates that we must limit peak demand to 51 GW by 2050 (down from a forecast peak of nearly 60 GW).[8]

On the other hand, if Massachusetts can manage new loads so that they use more electricity during off-peak hours, it can increase the overall utilization of the grid and spread infrastructure costs over a larger demand base, ultimately lowering rates (shown in Figure 2).

Figure 2: Load management can reduce rates in the long term.



[8] ISO New England, 2050 Transmission Study at 16. Peak demand growth between 28 – 51 GW adds $0.75 billion/GW in transmission costs, doubling to $1.5 billion/GW after the 51 GW threshold.

To ensure the affordability of the electric grid, it is important to manage peak demand using *load management*: a set of policies and technologies that help reduce the need for electricity in peak hours or in constrained areas of the grid. Load management includes both established tools like energy efficiency and new technologies like demand flexibility and virtual power plants (VPPs). By permanently reducing energy needs throughout the year, temporarily shedding load, or shifting load to off-peak times, load management can reduce the long-term cost of meeting a range of grid needs, as shown in Table 2.

To stay below the 51 GW threshold, ISO-NE estimates that the region needs roughly 8.5 GW of peak load reduction, spread across all six New England States.[9] To understand the potential for load management to meet this challenge, DOER commissioned Energy and Environmental Economics (E3) and the Applied Economics Clinic (AEC) to conduct the *Technical Potential of Load Management Study (Technical Potential Study)*. This DOER report reviews the current state of load management in Massachusetts, highlights key results from the Technical Potential Study,[10] and provides policy recommendations for unlocking load management as a tool for supporting energy affordability as we transition to a modern, decarbonized electric grid.

1.1 What is load management?

Load management refers to a set of policies and technologies that help reduce the need for electricity in peak hours or in constrained areas of the grid, either by permanently reducing demand (e.g., using energy efficiency), shifting demand to off-peak times (e.g., delaying EV charging), or temporarily curtailing energy use during peak hours (e.g., turning a thermostat down a few degrees). These measures are called *shape*, *shift*, and *shed* load management, respectively. Shape measures like energy efficiency are *passive*; they reduce demand in all hours and don't need to be controlled. In contrast, shift and shed measures are *active*, meaning that they rely on a signal from the grid operator to know when to activate. As Table 2 illustrates, load management can support the electric grid in a range of different ways, including by reducing the need for expensive peaker power plants[11] and grid upgrades.

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[9] ISO New England, "2024 Economic Study: Additional Policy Scenario & Stakeholder Requested Scenario Sensitivities" at 18. Presented at the Planning Advisory Committee on July 23, 2025.
[10] More details on the technical potential study are provided in E3's accompanying report at https://www.mass.gov/doc/e3-technical-potential-of-load-management-study-report/download
[11] Peaker power plants are generators that typically only run during hours where demand is near or at its maximum level. Peaker plants are often fossil fueled and more expensive to run than other power plants.

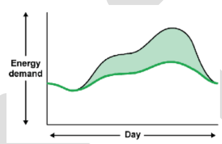
Examples of load management

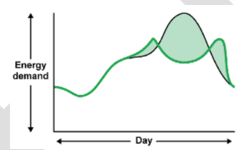
- **Energy efficiency** passively reduces demand for electricity in all hours.
- **Battery storage and EV management** shift demand to off-peak periods.
- **Smart thermostats** shed load during peak hours.

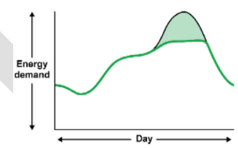
A **virtual power plant (VPP)** allows these measures to work together (potentially with other resources like rooftop solar) to maximize benefits to the grid.

Load management ***measures*** (technologies that reduce peak demand, like EVs) can respond to various ***incentives*** (e.g. utility programs or TOU rates).

Table 2: How load management supports different grid needs







		Shape[12]		*Shift*		*Shed*	
		Permanent reductions (e.g., energy efficiency)		Move load off-peak (e.g., battery storage)		Temporary reductions (e.g., curtailing load)	
Bulk System	***Energy*** *Using power at times when it is cheaper to produce.*	●		◐	Can shift daily in some cases (e.g. EVs)	○	Not suitable for frequent dispatch
Bulk System	***Capacity*** *Avoiding the need for dirty and expensive peaker plants.*	●	Reduces load at all times, including during peak	●	Annual peak reduction	●	Annual peak reduction
Bulk System	***Transmission*** *Avoiding or deferring infrastructure investment costs.*	●		●	Monthly peak reduction	●	Monthly peak reduction
Local	***Distribution*** *Avoiding or deferring infrastructure investment costs.*	●	Reduces load at all times, including peak load	◐	Can dispatch frequently in some cases	○	Not suitable for frequent dispatch
Building	***Resilience*** *Improving comfort and safety in extreme weather or power outages.*	●	Improves comfort & safety during outages	◐	Pre-cooling or pre-heating	○	Not applicable

[12] Shed, shift, and shape definitions and illustrations from U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants." September 2023.

The grid needs shown in Table 2 can occur at different times and require varying amounts of load reduction. As a result, no single load management tool can meet all needs, but a portfolio of diverse load management measures can combine to manage peak load. A *virtual power plant (VPP)* aggregates thousands of flexible distributed loads to act together to meet a diverse range of grid needs.

1.2 Current state of load management in Massachusetts

Massachusetts has a history of success in load management. In 2008, the Green Communities Act established the modern utility-administered energy efficiency framework in Massachusetts, Mass Save. Since then, Mass Save has grown into a nation-leading energy efficiency, load management, and decarbonization program, offering incentives for measures such as insulation, weatherization, and efficient appliances. In addition to passive energy efficiency, Mass Save includes active demand response through the ConnectedSolutions program, which allows commercial & industrial (C&I) customers, and residential customers with home batteries or smart thermostats, to shift and shed load in response to grid signals.

While Massachusetts has successful passive energy efficiency programs, the current landscape for active demand flexibility is more limited, particularly for residential customers. Figure 3 shows how, while C&I customers receive technology-neutral incentives to shift load (in the form of TOU rates, demand charges, and technology-neutral demand response), residential customers can currently only participate in load shifting programs if they have a home battery or smart thermostat. Figure 4 shows the current enrolled capacity in active demand response programs.

Figure 3: An overview of the current state of load management in Massachusetts

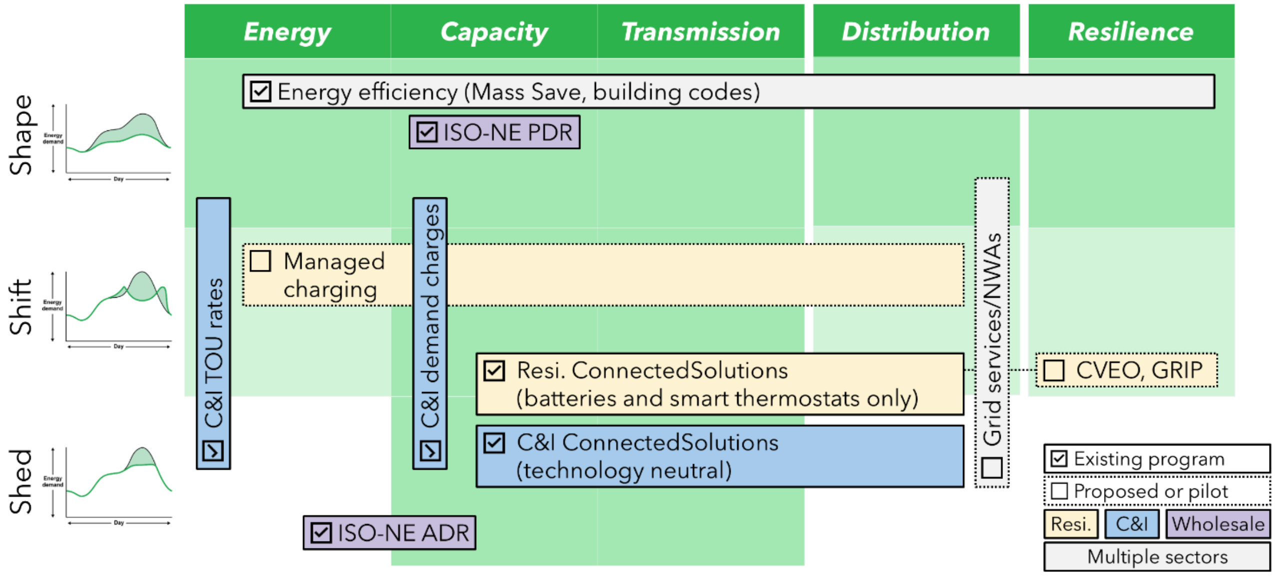
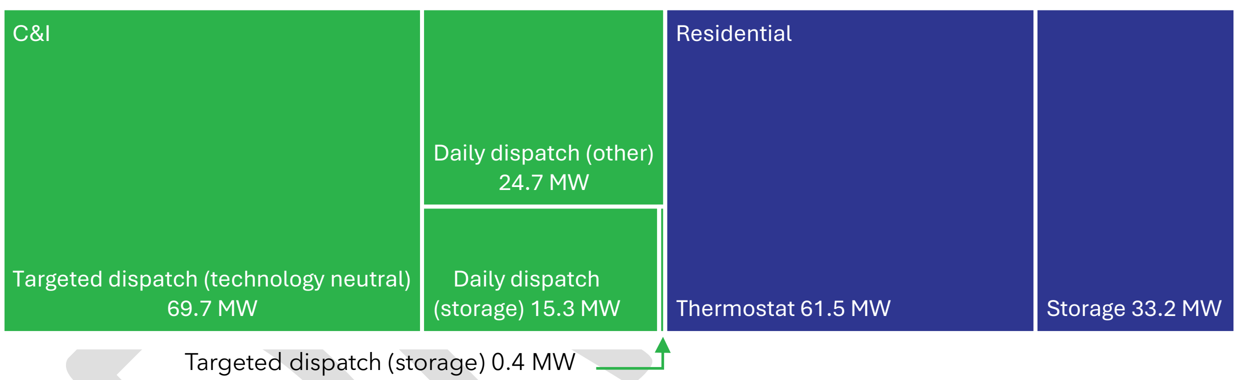


Figure 4: 2024 enrolled capacity in ConnectedSolutions, by sector and technology[13]



Sections 1.2.1 through 1.2.3 summarize the current landscape for load management at the residential, commercial & industrial, and wholesale levels. Appendix A provides more detailed information on these load management programs.

1.2.1 Residential customers

While residential customers have easy access to nation-leading energy efficiency programs through Mass Save, their access to active load management programs is more limited.[14] This limitation is largely due to the lack of smart meters statewide.[15]

[13] ConnectedSolutions Stakeholder Meeting – Fall 2024
[14] This discussion focuses on customers of Eversource, National Grid, and Unitil. Municipal utility customers may not be able to participate in Mass Save, but these utilities may offer other programs.
[15] Unitil and many municipal light plants (MLPs) have already deployed advanced metering infrastructure (AMI), but National Grid and Eversource are in the process of deploying AMI, with full deployment estimated by 2028 and 2029, respectively. See Interagency Rates Working Group, "Long-Term Ratemaking Recommendations" at 31.

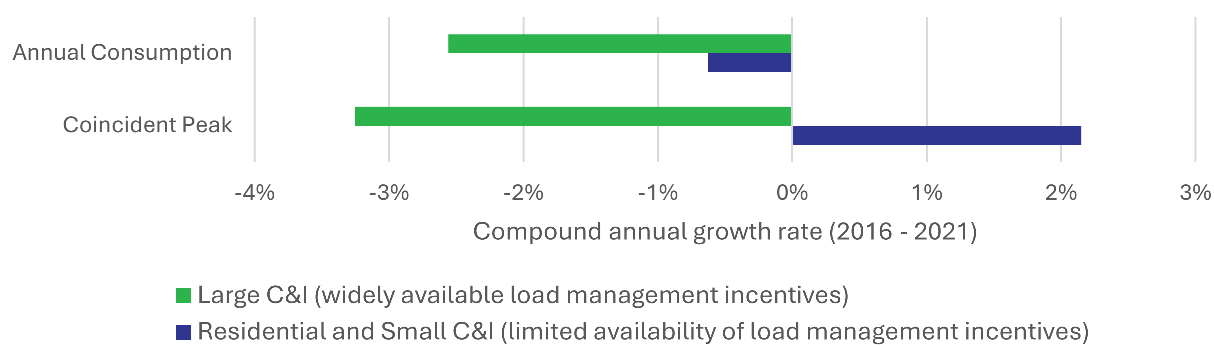
Smart meters are electric meters which can track electricity usage by appliance and on a sub-hourly basis, rather than simply tracking total usage at the end of a billing period. The Massachusetts electric utilities are currently deploying smart meters to all residential and small commercial customers in the state, with full deployment expected by 2028. Without smart meters, there is no way to credit customers for shifting their usage to reduce strain on the grid. As a result, residential customers cannot yet receive time-varying rates or participate in VPPs, so existing load management programs for residential customers are limited to energy efficiency (which reduces load at all times of day) and technology-specific programs for battery storage and smart thermostats (see Figure 3 and Appendix A: Table 5).

1.2.2 Commercial & industrial customers

Unlike smaller commercial customers, most large C&I customers in Massachusetts have smart meters.[16] Using these meters, Massachusetts utilities have already developed several technology-neutral, performance-based incentives for load management (see Figure 3 and Appendix A: Table 5).

Over the last ten years, these incentives have led to measurable reductions in peak load from large C&I customers. Figure 5 compares the change in annual energy consumption and coincident peak demand for customers with and without widely available load management incentives (large C&I customers vs. residential and small C&I customers, respectively). Between 2016 and 2021, both groups reduced overall energy consumption, but small residential and commercial customers *increased* their coincident peak demand. Over the same period, large C&I customers, who receive substantial incentives to manage peak demand, reduced their coincident peak load.

Figure 5: Large C&I customers have reduced peak load in response to load management incentives, relative to customers without access to those incentives.[17]



[16] "Large C&I" refers to customers on G2 and G3 rates, typically with >100 kW peak demand (threshold varies by utility). Small C&I customers face similar metering challenges to residential customers.
[17] Data from Eversource, National Grid, and Unitil rate cases (D.P.U. 22-22, 23-150, 23-80).

1.2.3 ISO-NE markets

ISO New England (ISO-NE) is the regional electric grid and wholesale market operator for the six New England states, including Massachusetts. Flexible loads can participate in ISO-NE wholesale markets to provide energy, reserves, and capacity, but currently only large customers participate because of metering and telemetry barriers.[18] Customers can participate in ISO-NE markets as Demand Response Resources (DRRs) either individually or as part of an aggregation. In either case, they must be able to provide interval metering data to participate in energy or capacity markets, and they must also provide real-time telemetry to participate in reserve markets.[19] Since residential and small C&I customers currently lack smart meters that can provide interval data, they cannot be part of DRRs. In addition, participating in ISO-NE markets involves fixed costs and potential risks (e.g., from failing to meet a capacity supply obligation) that discourage some customers.

Customers can currently participate in both ISO-NE markets and retail programs like ConnectedSolutions at the same time. However, because there is little coordination between retail programs and ISO-NE markets, there are issues around baseline erosion[20] and double compensation.[21] As smart meters become more widespread in Massachusetts and create the potential for wider demand response participation in ISO-NE markets, there will be a need for improved coordination between ISO-NE and retail programs.[22]

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[18] Sean Murphy and Cesca Miller, "Winter demand response value, potential, suitability to address winter energy shortfalls, and participation in ISO-NE wholesale markets." August 2025.

[19] ISO-NE 2222 Compliance Filing, May 9, 2023. https://www.iso-ne.com/static-assets/documents/2023/05/er22-983-further_order_no_2222_compliance.pdf

[20] Both ISO-NE and ConnectedSolutions measure demand reductions relative to a baseline determined by load on recent days and adjusted by the customer's demand immediately prior to the dispatch. If a customer reduces load multiple days in a row as part of ConnectedSolutions, this will reduce their baseline load for calculating ISO-NE payments. Similarly, if a customer reduces their load in response to a dispatch signal from one program, that would make them unable to respond to a subsequent dispatch signal from the other (since the day-of adjustment to their baseline would include the earlier load reduction).

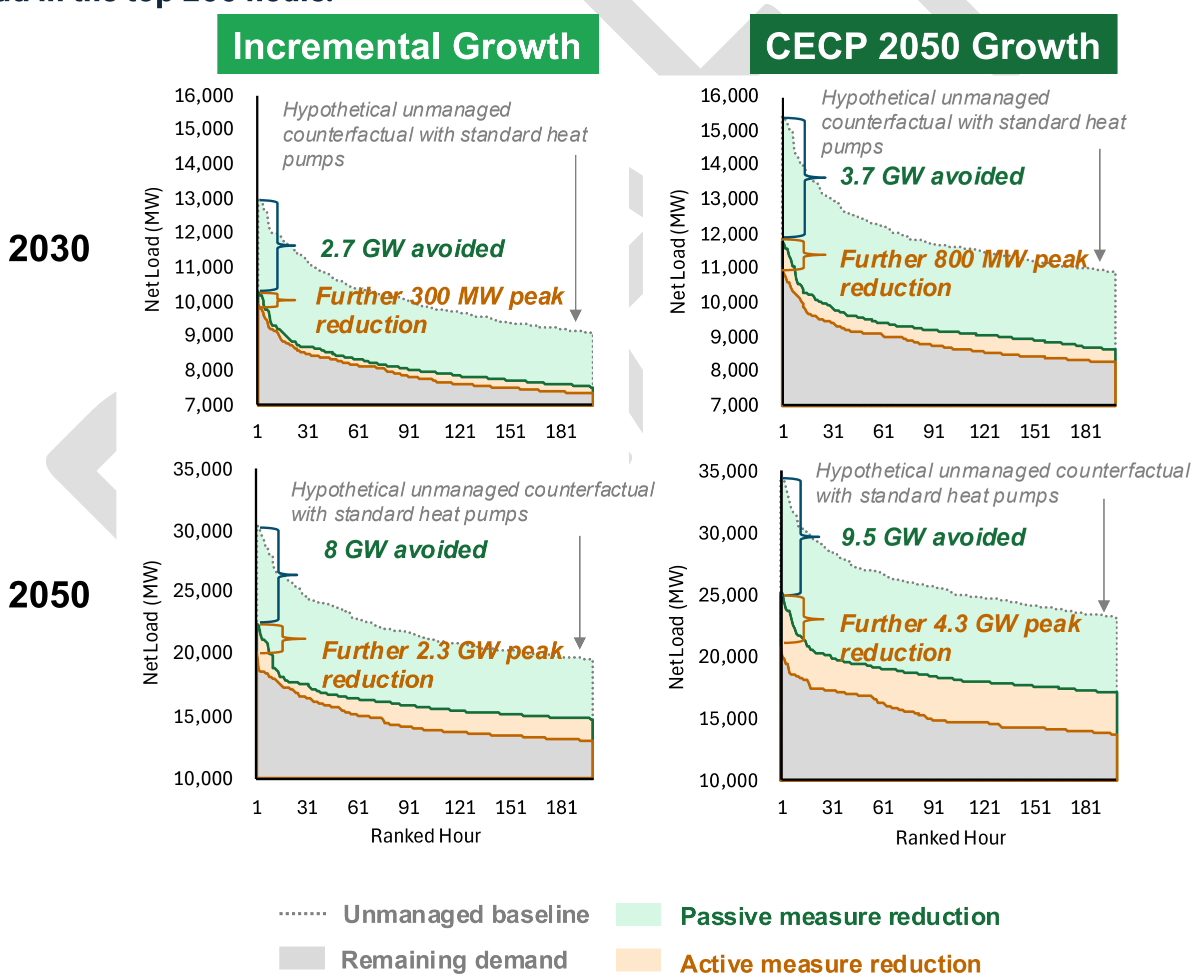
[21] Double compensation refers to cases where ConnectedSolutions and ISO-NE both dispatch a DRR to reduce load at the same time; the customer currently receives two payments for the same behavior.

[22] Sean Murphy and Cesca Miller, "Winter demand response value, potential, suitability to address winter energy shortfalls, and participation in ISO-NE wholesale markets." August 2025.

2 Key Findings from the Technical Potential Study

To quantify the potential for load management to reduce peak loads and save money for ratepayers, DOER commissioned Energy and Environmental Economics (E3) and the Applied Economics Clinic (AEC) to conduct the *Technical Potential of Load Management Study*. This study quantifies the feasible potential for load management in 2030, 2040, and 2050, and estimates the costs and benefits of different load management measures. For each year, the study includes two scenarios ("Incremental Growth" and "CECP 2050 Growth") that consider low and high rates of load growth and participation in load management programs. Figure 6 shows managed and unmanaged net load in the top 200 peak hours in 2030 and 2050 under both scenarios.

Figure 6: Effect of both passive and active load management on peak load, showing net load in the top 200 hours. [23]



[23] E3, "Evaluating Load Management Strategies for a Net-Zero Grid" at 10.

2.1 Energy efficiency is the foundation for load management

	2030	2050
	3.5 GW	9.5 GW

The Technical Potential Study considers four categories of passive energy efficiency measures: retrofits for existing buildings, energy codes for new buildings, cold-climate heat pumps, and GSHP. Since the inception of energy efficiency programs in Massachusetts, ISO-NE estimates that passive measures like these have reduced peak load by more than 1 GW,[24] and the Technical Potential Study estimates that there is nearly 9.5 GW of total feasible potential by 2050.[25] Figure 6 shows how passive measures work first to reduce peak load, serving as the foundation for active measures to provide further reductions.

Massachusetts has already made substantial progress in supporting passive energy efficiency. Almost all heat pumps sold in the state today are cold-climate heat pumps (although GSHPs are still nascent),[26] over 90% of the state's population lives in municipalities that have adopted either the stretch or specialized energy codes,[27] and Mass Save conducts over 100,000 home energy assessments for existing buildings each year.[28]

2.2 EV managed charging is a high-potential, no-regrets strategy, and V2X unlocks substantial additional potential

	2030	2050
	0.3 GW	6.5 GW

The Technical Potential Study identifies EVs as the single biggest source of load flexibility in each study year, providing 0.3 and 6.5 GW of peak load reduction capacity in 2030 and 2050, respectively. This potential includes both managed charging (V1G), where EVs shift charging to off-peak hours, and vehicle-to-everything (V2X), where EVs discharge back to the home or grid. EV adoption is already

[24] ISO-NE, "2024 EE Forecast Report." May 17, 2024.
[25] The study identifies 3.7/7.7/9.5 GW of total passive load management potential in 2030/2040/2050. This includes the effect of past policies supporting cold-climate heat pumps and existing building retrofits that are already reflected in utility and ISO-NE forecasts.
[26] Heat Pump Market Effects Indicators Update PY2023/2024 Final Report. Only cold-climate heat pumps are eligible for Mass Save incentives.
[27] Massachusetts Building Energy Code Adoption by Municipality
[28] Mass Save program data.

underway in Massachusetts, and managed charging is an extremely low-cost way to reduce the impact of EVs on the grid. V2X requires additional up-front customer investment (in the form of a bidirectional charger) but more than doubles the peak load reduction from each vehicle; as a result, the study shows that this investment is cost-effective for customers today.

Today, there are few opportunities for customers with EVs to participate in either managed charging or V2X.[29] In order to put this potential to work lowering costs for consumers, Massachusetts must rapidly scale its EV load management programs.

2.3 There is untapped potential for flexibility from heating and residential appliances

0.3 GW	1.1 GW
2030	2050

The Technical Potential Study shows that there is substantial cost-effective load reduction potential from cooling, space and water heating, and residential appliances: up to 0.3 and 1.1 GW of peak load reduction in 2030 and 2050, respectively.[30] Massachusetts could access this potential by giving residential and small commercial customers access to load management programs like TOU rates and ConnectedSolutions, which customers could use to save money by either manually shifting their behavior (with no up-front costs) or through automation.[31]

Today, residential customers with central AC can participate in ConnectedSolutions, but other appliances (heating systems, window AC, clothes dryers, etc.) are not currently eligible due to a lack of connectivity and cost-effectiveness in the current summer-peaking grid. Rather than expanding existing programs on a piece-by-piece basis as new device types become cost effective, technology-neutral incentives that pay for performance could enable broad access while ensuring cost-effectiveness.

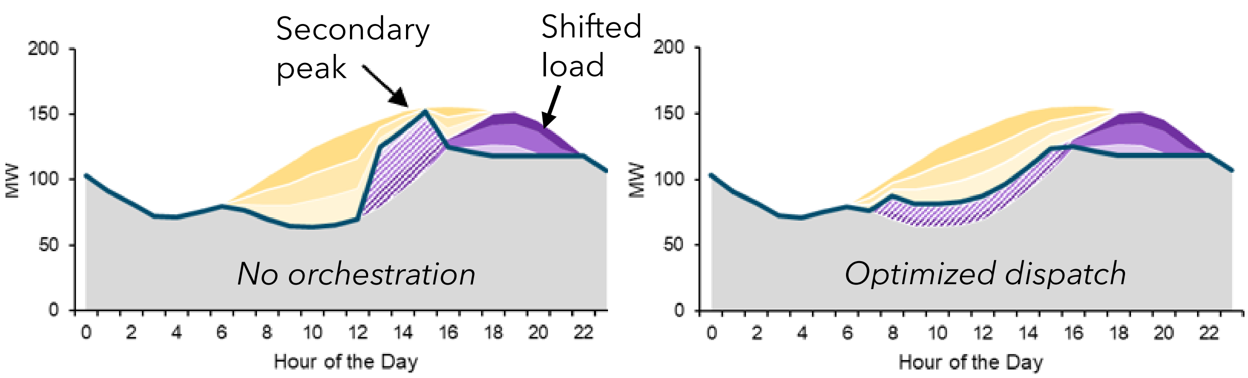
[29] Of the three investor-owned utilities, only National Grid offers a managed charging program, which is currently in the pilot stage.
[30] Total feasible potential (CECP scenario) of residential HVAC, water heating, and appliances. 2030 model summer peak load reduction; 2040 and 2050 model winter peak load reduction.
[31] The technical potential study assumes worst-case costs for appliance load management based on the current cost premium for smart appliances, but smart appliances are not a prerequisite to residential load management. In fact, limiting load management to only smart appliances can create additional barriers for renters and low-income customers to access these programs.

2.4 Aggregation and optimization will help maximize benefits

The Technical Potential Study estimates that the future grid will include large amounts of active demand response: 0.3–0.8 GW in 2030 and 2.3–4.3 GW in 2050.[32] Massachusetts needs to aggressively pursue this potential benefit through more coordinated policies. At this scale, demand flexibility can deliver large benefits to ratepayers but can have a substantial impact on both the bulk power system and the distribution grid. The study highlights how demand flexibility can create secondary peaks that could stress transmission and distribution networks if utilities or aggregators do not carefully dispatch flexible loads.[33] The study shows that optimal dispatch of flexible resources could reduce the size of transmission-level secondary peaks by nearly 3 GW (the study did not quantify the size of secondary peaks at the distribution level).[34]

As demand flexibility scales in Massachusetts, there will be an increased need for aggregation and optimized dispatch of these resources. Aggregators and other technology providers can help customers and utilities implement these advanced dispatch programs, maximizing the benefits of load management.

Figure 7: Benefits of orchestration to maximize the benefits of demand flexibility



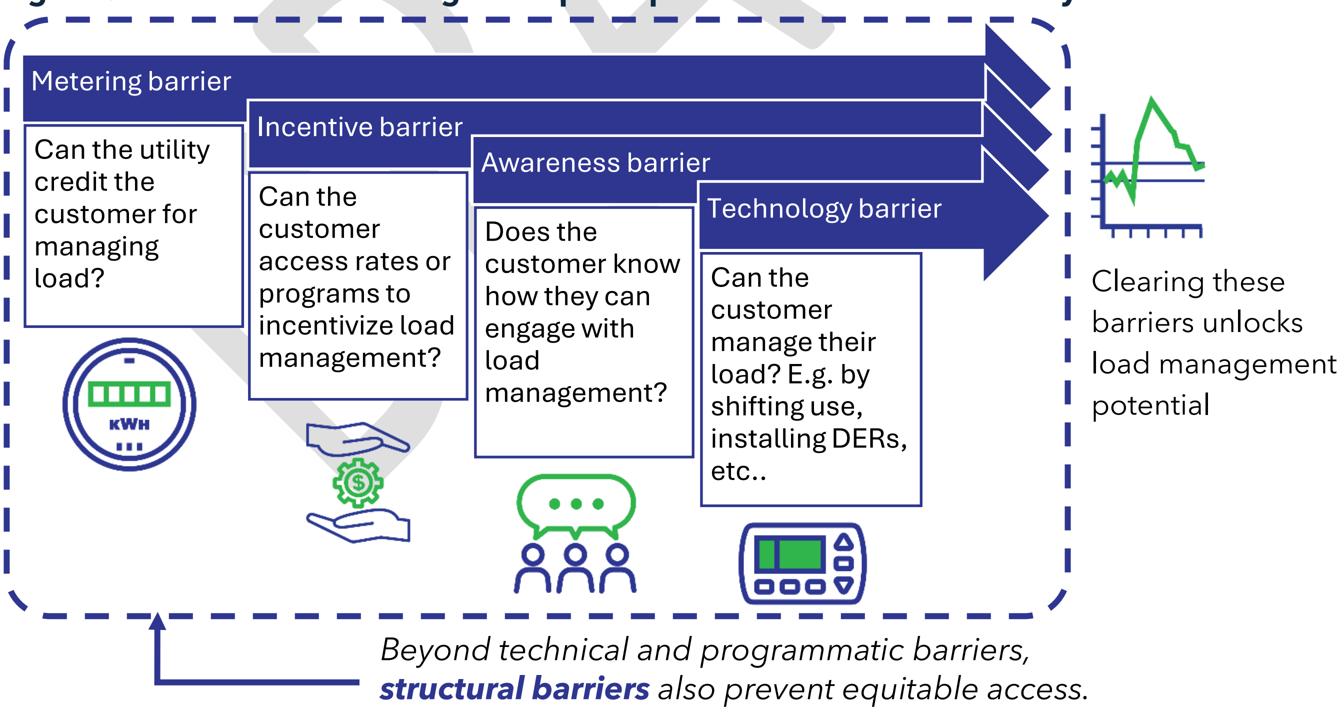
[32] The range shows the two feasible potential scenarios.
[33] For example, a secondary peak may occur if all EVs in a neighborhood start charging at the start of an off-peak charging window, the resulting surge could overload the local distribution circuit.
[34] E3, "Evaluating Load Management Strategies for a Net-Zero Grid" at 33.

3 Present Challenges for Load Management

What prevents Massachusetts from realizing the full potential of load management? Much of the untapped potential is in the residential sector, but high barriers to entry currently limit the ability of residential customers to participate in load management.[35]

To access most load management options today, residential customers must clear several hurdles. First, a customer must have a meter or other technology that can measure and credit any change in their electrical demand. Usually, advanced metering infrastructure (AMI or "smart meters") fills this role, but programs may also use meters embedded in equipment like battery inverters, appliances, and EV charging equipment. This barrier largely depends on utilities' progress in deploying investments in smart meters and distributed energy management systems (DERMS), which are underway but won't be completed until 2028. Once a customer has a meter, they must then have access to rates or programs that incentivize load management, and they must be aware of these programs. Only after clearing these three barriers (metering, incentives, and awareness) will customers consider buying equipment to enable flexibility, but they may still face challenges from high up-front costs of technologies like smart thermostats and storage.

Figure 8: Barriers to load management participation in Massachusetts today.



[35] In contrast to the residential sector, the C&I sector has a robust load management ecosystem that combines rates, demand response programs, and third-party aggregators.

In addition to these explicit challenges, structural barriers prevent customers from equitably accessing load management programs. For example, low-income customers may struggle to finance DERs like storage, renters depend on landlords to install energy efficiency or flexible appliances, and health conditions may prevent some customers from shifting their heating and cooling demand use.

Within the existing technological constraints, Massachusetts has managed peak system load with narrowly targeted incentives. For example, residential customers with batteries can participate in demand response through ConnectedSolutions using their battery's built-in meter to measure performance. These programs have already reduced peak load (as shown in Figure 4),[36] but several challenges remain.

First, today's active load management programs for residential customers are narrowly focused. Customers must buy specific equipment before participating, and programs cannot expand to new device types until they prove cost-effectiveness.[37] These limitations lock many customers out of load management; for example, central AC can participate in demand response today, but window units (common among renters) cannot. Rather than expanding eligibility on a device-by-device basis, technology-neutral programs using smart meters can help expand access.

Second, residential customers are limited to a small set of utility-run load management programs, although some utilities plan to pilot new incentives such as behavioral demand response and whole-home demand response in the current Energy Efficiency Three-Year Plan.[38] Currently, there is no way for aggregators or municipalities to reduce costs by bringing innovative load management programs (like residential VPPs) to market. In contrast, large C&I customers have much more freedom, including the ability to work with third-party aggregators to reduce costs.

Finally, existing programs are designed and evaluated in silos, with minimal ability to assess how they work together to support the grid. For example, smart thermostat and battery programs fall under the three-year energy efficiency plans, while EV programs are handled through a separate process. Many of these programs are also separately funded, typically through separate charges on customer bills. There is currently no venue for evaluating interactions between programs or whether the overall portfolio of load management is adequately meeting Massachusetts' needs.[39]

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[36] 2023 Statewide Electric Energy Efficiency Data Tables
[37] During the preparation for each three-year energy efficiency term.
[38] 2025-2027 Energy Efficiency Three-Year Plan at 144, 322.
[39] For example, competition between measures may lead to diminishing marginal reliability value of peak load reductions, as discussed in E3's technical report.

4 A Vision for Load Management

To realize the benefits of load management – $950 million in annual avoided electric system costs by 2030 and $4.8 billion by 2050 – Massachusetts will need to evolve its approach to load management to more aggressively expand capacity and ensure that incentives are aligned to meet the Commonwealth's resource needs.

Today, the fundamental problem is that people lack options for managing their energy costs by reducing peak demand. These examples show the challenges that residents face, their current options, and a vision for helping these customers meet their needs through load management.

Example 1

	You've just bought an electric vehicle, and you're excited to stop paying for gas! What can you do to save money on charging?
Options Today	If you live somewhere with a utility-run managed charging program… And you bought an eligible EV… And you use your utility's app… Then you can save by charging off-peak. If not, you pay the full rate.
Vision for the Future	No matter where you live or what EV you drive, you can save money by charging during off-peak times. You can do this yourself, or your utility can help you, or you can work with a third party; up to you! You can also invest in a charger that allows your vehicle to power your home during power outages or earn money by discharging to the grid (through vehicle-to-grid and vehicle-to-everything programs).

Example 2

	You live in a town with a municipal aggregation, and your town's energy manager wants to encourage residents to shift their energy use to reduce the town's peak demand.
Options Today	Customers of investor-owned utilities can't reduce their bills by reducing peak demand.
Vision for the Future	If you and your neighbors reduce demand when the town sends out an alert, the price you pay for electricity supply can go down.

Example 3

	Your community is electrifying, and your utility has decided that it needs a new substation nearby to meet this new demand.
Options Today	There are few other options; the utility must build the substation to maintain safe and reliable electric service.
Vision for the Future	Your community adds a battery and deep energy retrofits to the local school, and adopts V2X for some municipal vehicles, reducing its load enough to avoid the need for a new substation. Bills go down and your community becomes more resilient.

In this vision, ***load management provides options for people to take control of their energy costs.*** How do we achieve this vision? The principles in Figure 9 can help guide the next stage of load management in Massachusetts, focusing on high-impact opportunities for load management.

Figure 9: Principles for empowering customers through load management.

Principle 1: Sustain Massachusetts' lead on energy efficiency
Principle 2: Scale EV load management as a no-regrets strategy
Principle 3: Pay customers for supporting the grid
Principle 4: Support innovation in customer-centric aggregation
Principle 5: Ensure equitable access and distribution of benefits
Principle 6: Align utility business models with load management

Principle 1: Sustain Massachusetts' lead on energy efficiency

While there is work to be done to enable active load management, Massachusetts leads the nation in **passive load management** through the Mass Save energy efficiency program and the stretch and specialized building energy codes. Over the past two decades, energy efficiency has saved Massachusetts an estimated 1 GW of peak demand,[40] and the Technical Potential Study shows that continued investment in energy efficiency can save a further 3.7 GW in 2030 and 9.5 GW in 2050.

> ***Passive load management*** *refers to measures like traditional energy efficiency and new building energy codes that provide coincident peak reductions by reducing energy demand in all hours (including peak hours). The technical potential model applies passive load reductions first, providing the foundation for active measures like demand response, which layer on to provide additional peak demand reductions.*

Peak demand in New England is currently driven by air conditioning, and the growth of electric space heating will shift the peak to winter months in the mid-2030s.[41] Continuing to invest in passive load management like energy efficiency can help reduce these peaks, save money for customers, and create more comfortable and healthier homes.[42] There are three ways for Massachusetts to double-down on energy efficiency, outlined here and examined in more detail in Section 5.

First, more than 90% of the state lives in communities that have adopted the stretch or specialized energy codes.[43] In these communities, load management goes hand in hand with building development, since new buildings are required to be highly efficient and will reduce future space heating demand. As a result, measures that support housing affordability can also provide load management benefits, such as Massachusetts' recent effort to fast-track environmental reviews for housing projects that meet the stretch energy code.[44]

Second, while the Technical Potential Study found that measures like deep energy retrofits were not economical on a statewide basis, these measures may be cost

[40] ISO-NE, "2024 CELT Report." May 17, 2024.
[41] Eversource, "2025–2029 Electric Sector Modernization Plan" at 14.
[42] Technical Potential of Load Management Study at 52–55.
[43] Massachusetts Building Energy Code Adoption by Municipality
[44] Press Release, "Governor Healey Unveils Nation-Leading Plan to Cut Environmental Regulations to Fast-Track Housing Development." September 9, 2025.

effective solutions to acute grid needs in specific locations (e.g., in a neighborhood with a constrained distribution grid or gas-electric transition needs).

Finally, while Mass Save includes targeted efforts to reach renters, low-income residents, and small businesses, there is still work to be done to ensure that all energy-burdened users can access the benefits of passive load management. Principle 4 below examines this issue in depth along with other equity implications.

Principle 2: Scale EV load management as a no-regrets strategy

EV load management includes both managed charging and vehicle-to-everything (V2X). Using these two technologies, the Technical Potential Study shows that Massachusetts can achieve 300 MW of highly cost-effective peak load reduction by 2030, scaling to 6.5 GW by 2050.

Managed charging is a proven, mature strategy that can deliver both near- and long-term savings at very low incremental cost. In the short term, Massachusetts utilities should implement and scale managed charging programs[45] and take steps to minimize friction and maximize enrollment (e.g., through default or point-of-rebate enrollment). Many municipal utilities in Massachusetts have already implemented these programs, demonstrating that utilities both with and without smart meters and TOU rates have been able to benefit from managed charging.[46] DOER can also explore opportunities to work with equipment manufacturers to help ensure that managed charging works out of the box for EVs sold in Massachusetts.

V2X has also been proven at facilities throughout the United States, particularly for medium- and heavy-duty EVs. The study shows that V2X can provide cost-effective load reductions, but policy change is needed to support interconnection, incentives, and reliable operation of EV discharge.

For both managed charging and V2X, utilities and aggregators will need to actively manage EV loads to maximize benefits and minimize impacts on the distribution system. Without active managed charging, off-peak price signals can cause large numbers of EVs to begin charging at the same time, potentially overloading local distribution infrastructure. Similarly, EV discharge through V2X can cause reverse

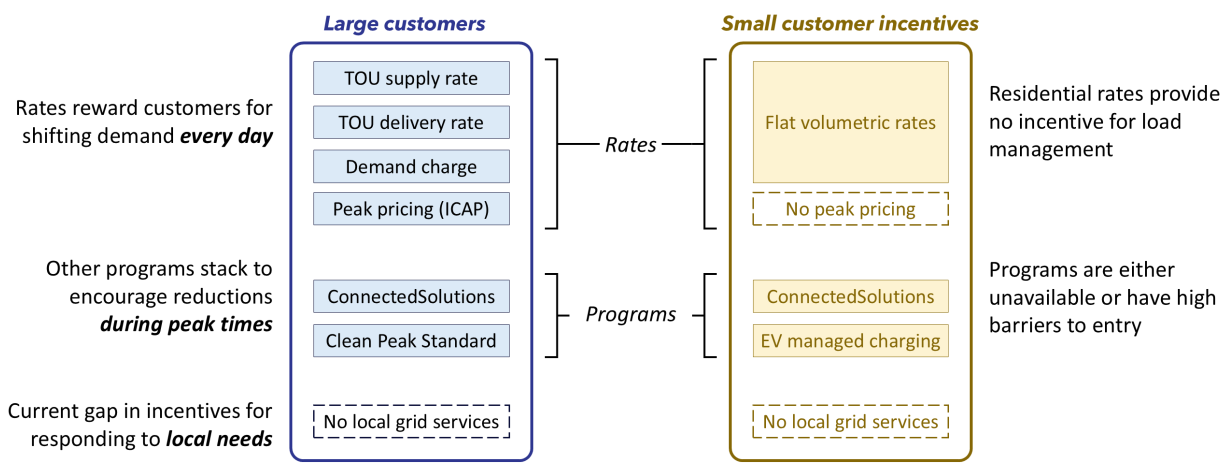
[45] As of September 2025, only National Grid has a pilot managed charging program, which is currently not enrolling new customers. National Grid, Eversource, and Unitil have all requested regulatory approval to begin full-scale managed charging programs. D.P.U. 24-196 Exhibit NG-EV-MTM-1 at 23. D.P.U. 24-195 Exh. ES-EV-MTM-1 at 33; D.P.U. 24-197 Exh. FGE-CCTP-1 at 14.
[46] See NextZero offerings from Massachusetts Municipal Wholesale Electric Company (MMWEC).

power flow[47] in some cases, requiring coordination with the distribution utility to maintain reliability. All three Massachusetts electric distribution utilities are advancing their capacity to manage distributed energy resources as part of their grid-modernization efforts,[48] and active EV load management is a high-impact opportunity to put those investments to work.

Principle 3: Pay customers for supporting the grid

Today, if a residential or small commercial customer wants to manage their load, there are only a few ways they can do so. These customers have no general-purpose load management incentives like TOU rates and are limited to programs that require installing expensive equipment like batteries. In contrast, large commercial and industrial customers can not only access a wider range of incentives (including TOU rates) but also work with a third-party energy manager or aggregator to help navigate them.

Figure 10: Contrast between load management incentives for large and small customers. Small customers include residential and small C&I customers.



While residential and C&I customers differ in many ways, there are three lessons from the success of existing C&I load management incentives. First, these incentives are *technology neutral* and *paid based on performance*. Customers can adopt new technology like batteries or building automation if they wish, but they can also manually adjust their energy usage and access the same cost savings. These programs pay customers based on the benefits they provide by reducing peak load.

[47] Reverse power flow occurs when power flows from customers to the grid. Large amounts of reverse power flow can cause challenges for the distribution grid and require upgrades or reconfiguration.
[48] See D.P.U. 24-10-A/24-11-A/24-12-A at 161.

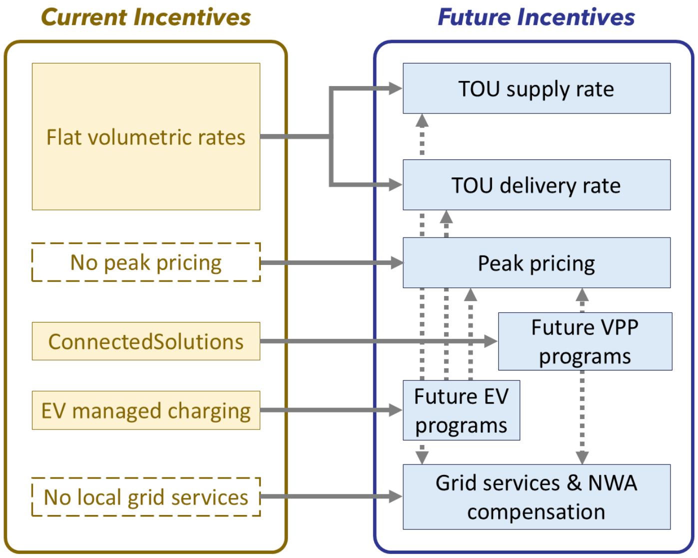
Second, these incentives are *layered* to address multiple grid needs. For example, TOU rates help customers use energy when it is cheapest, while peak pricing and ConnectedSolutions reduce the need for expensive peaker plants.[49] Customers can stack different incentives based on their capability and willingness to shift load.

Finally, these incentives are *open access,* meaning that customers can choose to participate on their own, work with their utility, or work with a third-party energy manager or aggregator. This flexibility supports innovation, as aggregators may be able to offer products that utilities cannot (e.g., combining retail incentives with participation in ISO-NE markets). There is also up-front support for customers who want to install new equipment or automation to take advantage of these incentives; for example, Mass Save provides incentives for C&I customers who install building energy management systems for demand response.[50]

Figure 11 shows how existing residential programs can evolve to incorporate these best practices. Broadening access to these incentives will help load management scale, and linking compensation to performance will ensure that load management delivers cost-effective savings for ratepayers. Section 5.1 provides a roadmap for making these changes in the existing regulatory framework. In addition to TOU rates and peak pricing (as the Interagency Rates Working Group explores in its report[51]), grid services compensation provides an important piece of the future value stack. Grid services programs pay flexible loads and other DERs for deferring or avoiding traditional infrastructure investments. In the recent Electric Sector Modernization Plans, the Department of Public Utilities (DPU) approved a Grid Services Compensation Fund and accompanying MassCEC Grid Services Compensation Study[52] as important first steps towards adding a grid services layer to the incentive stack.

[49] Participating in multiple programs is typically allowed, although some programs limit double compensation.
[50] 2025-2027 Energy Efficiency Three-Year Plan at 137.
[51] MA Interagency Rates Working Group, "Long-Term Ratemaking Recommendations." March 2025.
[52] Energy and Environmental Economics, "DER-iving Local Value: Distribution Grid Services in the Commonwealth of Massachusetts." September 2025.

Figure 11: Evolving residential load management incentives



Implementation Pathway

- *DPU investigation into TOU rates.*
- *ConnectedSolutions pilot of **whole-home incentives** in '25-'27, enrolled devices may provide **grid services** under future grid services programs.*
- *EV programs evolve once TOU rates are widely available and explore **active management** to reduce distribution-level impact.*
- *NWA compensation pilots in '25-'29 ESMP term*

Principle 4: Support innovation in customer-centric aggregation

Although utility-run programs have helped get load management off the ground in Massachusetts, they are currently limited to a few products and value streams. For example, peak load reductions from ConnectedSolutions currently benefit all customers through reduced capacity charges in the short term[53] and reduced delivery costs in the long term. However, there are currently no offerings that bundle load management with decreased supply rates (e.g. via municipal aggregations). If municipalities or aggregators have innovative ideas for new supply-side load management offerings to save customers money, there is currently no way to bring those to market for customers of investor-owned utilities.

As load management programs evolve, utilities can transition from their current role as sole providers of load management to a new role as facilitators of a load management ecosystem. Customers could then choose whether to participate directly in the utility program or through a third party like their municipal aggregation. Aggregations could help customers navigate incentives and develop new automation tools; for example, bundling smart thermostats with ConnectedSolutions and wholesale capacity savings. Combining multiple customers into an aggregation or VPP can also improve reliability and provide a new hedging tool for supply contracts.

[53] In the short term, peak load reductions shift capacity costs between customers based on relative load during peak hours. In the long term, peak reductions reduce the amount of capacity procured through ISO-NE capacity markets, reducing costs.

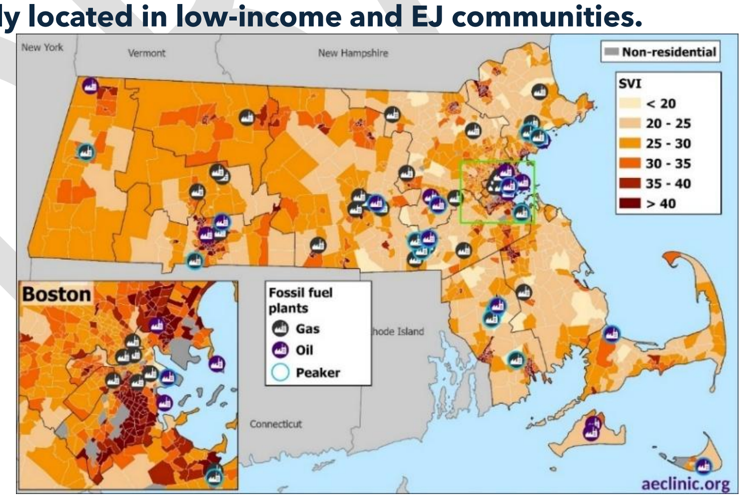
Enabling more experimentation and innovation in load management has important equity considerations. While there are important consumer protection concerns when increasing the role of third parties like aggregators, there are also benefits from empowering communities – through municipal aggregations – to adopt load management programs based on local needs and concerns.

Practically, unlocking further innovation will require giving customers price signals for load management (as shown in Figure 11), tying compensation to performance to avoid cost shifts, ensuring that municipalities have access to technical support to develop these offerings, and paying careful attention to consumer protection.

Principle 5: Ensure equitable access and distribution of benefits

The Technical Potential Study found that there is an opportunity for $4.8 billion in annual avoided electric system costs by 2050 through load management. Historically, homeowners and high-income customers have been most able to access energy efficiency and DERs like solar and storage, while renters and low- and moderate-income (LMI) customers have faced barriers.[54] At the same time, the impacts of peak load (such as high electricity rates and emissions from peaking power plants) fall disproportionately on disadvantaged communities (as shown in Figure 12). As Massachusetts works to scale load management, it is important that all ratepayers share equitably in the benefits.

Figure 12: AEC's social vulnerability index (SVI) shows how peaking power plants are disproportionately located in low-income and EJ communities.



The Technical Potential Study outlines important equity and EJ considerations for load management. Stakeholders provided substantial feedback both in this study and in

[54] 2025-2027 Energy Efficiency Three-Year Plan at 27.

MassCEC's Grid Services Valuation Study.[55] Feedback from these stakeholders highlights important principles for ensuring equitable access to and benefits from load management:

1. Meaningfully engage EJ stakeholders in program design.
2. Ensure equitable structure and procedural access for LMI customers & renters.
3. Support DER ownership and wealth creation in EJ communities.

Moving forward, Massachusetts can sustain existing efforts to improve access, scale promising new initiatives, and continue engaging affected communities in program design and decision making (particularly for new programs or policies that directly affect those communities). Municipal aggregations can also serve as platforms for community-informed load management program design.

Existing efforts include Mass Save's ongoing efforts to reach renters and LMI households with passive energy efficiency measures. This includes a record $1.8 billion in equity investments planned for the current 2025-2027 energy efficiency term,[56] with funding to address barriers to weatherization like mold and asbestos, support for deep energy retrofits, and incentives for program administrators to reach a target number of renters and LMI customers.[57] Moving forward, Massachusetts electric utilities can monitor and evaluate these programs to ensure they are successfully reaching LMI households and modify them if needed in the next efficiency plan term.

Promising new initiatives include efforts to support broad access to DERs, such as the Generac Grid Services project to help up to 2,000 LMI households buy behind-the-meter batteries,[58] the Cape Light Compact's CVEO offering that pairs solar, storage, energy efficiency, and electrification for low- and moderate-income customers,[59] and National Grid's income-eligible VPP offering in its ESMP.[60] Future efforts can explore sustainable funding models to expand such efforts to scale beyond the pilot stage; for example, through the inclusive utility investment model in the Healey-Driscoll Administration's proposed Energy Affordability, Independence & Innovation Act.[61]

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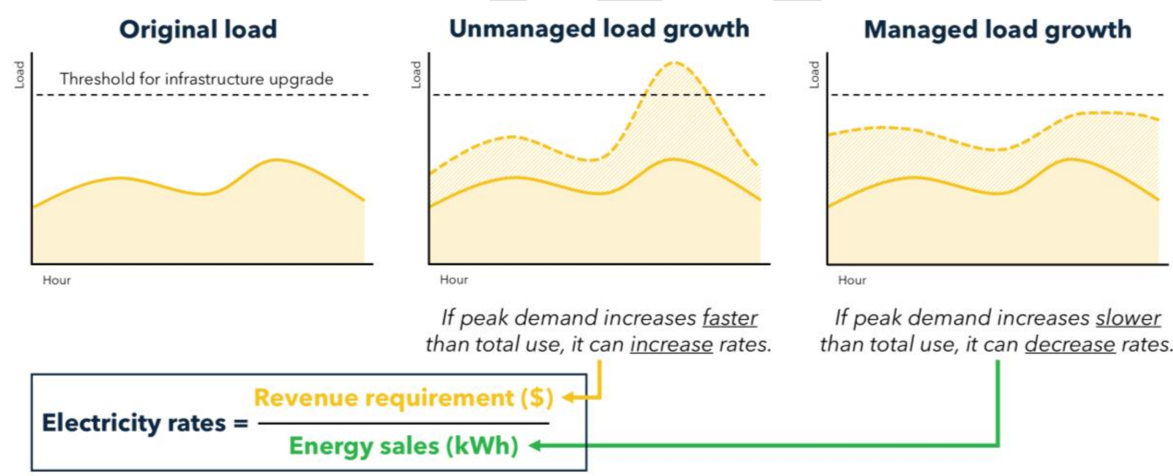
[55] Energy and Environmental Economics, "DER-iving Local Value: Distribution Grid Services in the Commonwealth of Massachusetts." September 2025.
[56] D.P.U. 24-140 – D.P.U. 24-149 2025-2027 Three Year Plan April 30, 2025 Compliance Filing at 5.
[57] 2025-2027 Energy Efficiency Three-Year Plan at 27.
[58] See Generac Grid Services, "Generac Grid Services selected for $50M DOE grant in Massachusetts." October 2023.
[59] Olivia Tym, "Solar+Storage+Electrification: A Clean Energy Equity Model For Massachusetts." Clean Energy Group. March 24, 2025.
[60] D.P.U. 24-11 National Grid Future Grid Plan at 342.
[61] Section 52 of the proposed bill.

Principle 6: Align utility incentives with affordable load growth

Electrification and economic growth will increase demand on the electric grid, but load growth does not necessarily need to lead to increases in customer bills. Responsibly managing new load is a core strategy for policy makers and utilities to control future rate increases.

Figure 13 illustrates the effect of long-term load growth and load management on electricity rates. The cost of utility infrastructure is largely driven by peak demand: when peak demand increases, the utility must invest in equipment like substations and power lines. These costs increase the utility's *revenue requirement*, the amount of money it must recover through rates. In turn, utilities set rates by dividing the revenue requirement by the total amount of electricity sold. If peak demand increases faster than average demand, the utility must charge a higher rate to cover the cost of increased infrastructure. In contrast, if peak demand grows more slowly than average demand (e.g. if load shifts out of peak hours), the utility can spread its costs over a greater denominator of total energy sales, lowering rates.

Figure 13: Load management can reduce rates in the long term.



The ratio between average and peak demand is called the *load factor*,[62] and it is key to understanding how load growth will affect energy affordability in Massachusetts. Under the existing regulatory framework, utilities have few incentives to improve their load factor. Regulators must fill this gap, and Section 5.2 recommends reforms to align utility incentives with load management.

[62] Load factor equals average demand divided by peak demand, and it can be computed at different levels (e.g. a building, feeder, substation, or region). A load factor of 100% indicates that the system has constant load; real systems will have a lower load factor (e.g., 54% for all of ISO-NE in 2024).

5 Recommendations

This section lays out recommendations for maximizing the potential for load management to reduce costs for ratepayers. These recommendations, summarized in Table 3, span policy, regulatory, legislative, and technology domains and implement the core strategic principles from Section 4. As shown in

Figure 14, Massachusetts has a credible path towards implementing these recommendations by 2030, starting with changes that can be implemented today.

Table 3: Summary of recommendations

Principle 1: Sustain Massachusetts' lead on energy efficiency by continuing to invest in building energy retrofits and efficient new construction.
New Buildings: support expansion of stretch and specialized codes. Accelerate the construction of efficient new buildings. **Existing Buildings:** continue to invest in retrofits for existing buildings and explore opportunities for deep energy retrofits in grid-constrained regions. **Large Buildings:** diagnose bottlenecks in load management adoption for large buildings using energy reporting data. **Ground-source heat pumps (GSHP):** evaluate opportunities for up-front incentives and workforce development to support GSHP deployment, especially in constrained regions of the grid.
Principle 2: Scale EV load management as a no-regrets strategy for reducing peak load. Invest in active managed charging and V2X to maximize benefits and minimize grid impacts.
Managed charging: scale up residential EV managed charging programs. Develop managed charging programs for commercial customers. **V2X:** develop interconnection policies, interoperability standards, and incentives. **Active EV management:** use active managed charging and grid-aware V2X dispatch to maximize benefits and minimize negative grid impacts.
Principle 3: Pay customers for supporting the grid with easy-to-use, low-friction incentives like TOU rates and technology-neutral demand response.
Electric rates: develop a default seasonal TOU rate for residential and small commercial customers. **Peak pricing:** explore technology-neutral incentives like critical peak pricing, whole-home demand response, and other advanced rate designs.

Principle 4: Support innovation in customer-centric aggregation, particularly through municipal aggregations, to develop new load management technologies and products.

Residential VPPs: scale technology-neutral demand response pilots in the 2025–2027 energy efficiency plan to full-scale programs in future years.

VPP-ready equipment: Investigate standards or market development policies to support adoption of flexible appliances.

Customer-centric innovation: support technology and business model innovation to reduce supply costs for customers (e.g., bundling load management with municipal aggregation supply contracts).

Retail/wholesale coordination: Increase coordination of retail demand response with wholesale markets, explore options to participate in ISO-NE markets.

Principle 5: Ensure equitable access and distribution of benefits by minimizing cost shift from load management programs, reducing barriers to access and DER ownership for renters and low-income customers, and focused outreach.

Avoid cost shift: avoid shifting costs to non-participants by calculating compensation for load management based on benefits provided to the grid.

Address barriers to participation: develop technology-neutral incentives where customers can participate without expensive equipment like smart appliances. Engage communities with outreach to educate customers on load management options and receive feedback on program design.

Support DER ownership: investigate up-front incentives to support measures like home energy retrofits and storage that reduce energy burden, provide health and resiliency benefits, and help households build wealth.

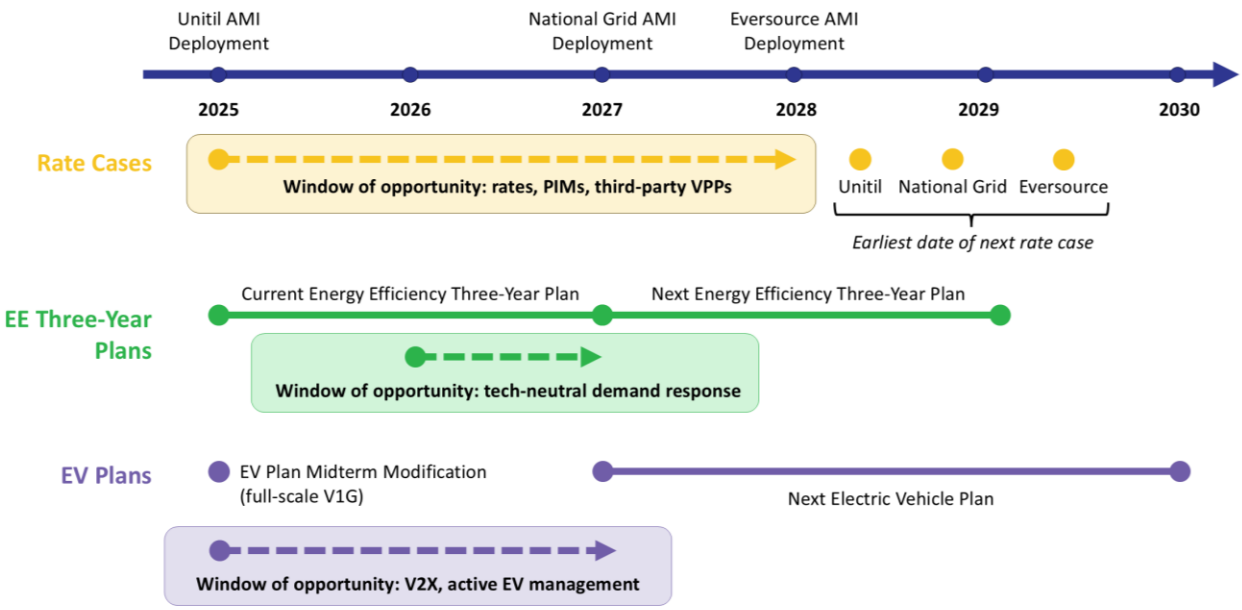
Principle 6: Align utility business models with load management through appropriate incentive mechanisms and regulatory frameworks.

Incentive mechanisms: investigate utility incentive mechanisms that balance electrification with managed load growth (e.g. system utilization incentives).

Integrated planning: improve the use of load management in utility planning (e.g. through integrated distribution system planning).

Regulatory sandbox: provide a constructive regulatory environment for utilities to experiment with new load management tools.

Figure 14: Opportunities for implementing recommendations (other recommendations do not depend on set regulatory timelines).



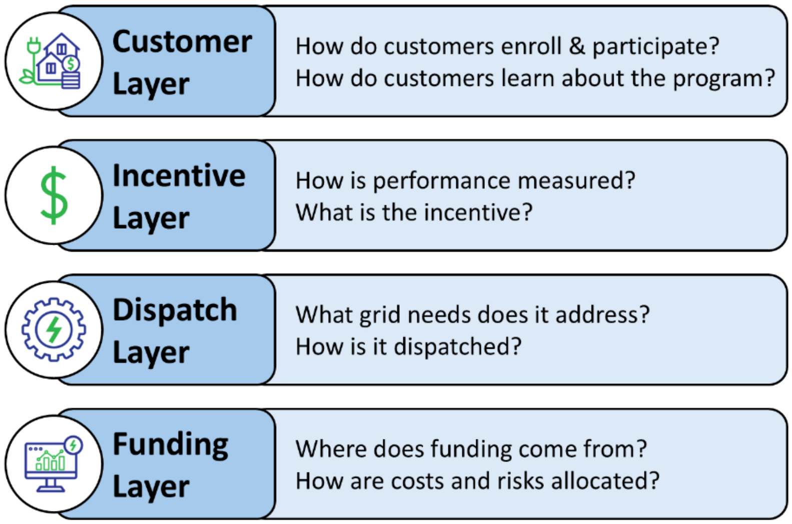
5.1 Policy & programmatic changes

This section provides a framework for program design principles and recommendations to support Massachusetts' progress towards increased load management.

5.1.1 Program design principles

Unlocking the benefits of load management will require program designs that minimize friction, reduce costs, and maximize benefits to ratepayers. Figure 15 illustrates the four design layers of a typical load management program.

Figure 15: Anatomy of a load management program.



Different programs will naturally have different answers to the questions in each design layer; however, there are best practices that hold across programs. These best practices aim to enable broad participation, tie compensation to net benefits, and consolidate funding for load management programs.

Customer Layer

- *Minimize friction:* use default or opt-out enrollment to minimize friction for enrollment and participation, paired with education and respect for customer autonomy. Tailored offerings for specific technologies can help improve customers' experience (e.g. EVs).
- *Meet customers where they are:* use trusted partners and channels to help customers understand options for participation (e.g. EV OEM apps to educate customers about managed charging). Help customers learn but also support customers who want load management to "just work."
- *Provide a technology-neutral "backstop" for broader participation:* while tailored offerings can reduce friction, customers should also be able to manage load without buying new equipment. For example, while a tailored offering for smart thermostats can reduce friction through automatic dispatch, pre-cooling, etc., customers who manually adjust their thermostat should also be able to participate via a technology-neutral offering.

Compensation Layer

- *Pay for performance:* Programs and rates should pay customers based on the value they provide for the grid, regardless of the technology used. Payments to participants should not exceed the value delivered; otherwise, costs may shift to non-participants. As a model, ConnectedSolutions' technology-neutral $/kW compensation for C&I customers is based on measured performance (as opposed to flat per-season payments).

Dispatch Layer

- *Adapt to changing grid needs:* grid needs are likely to change over time. Programs should be able to adapt to target emerging grid needs. For example, EV managed charging programs may initially target moving load out of system-wide peaks, but they may transition to targeting local constraints once time-varying rates are deployed.
- *Improve coordination with ISO-NE: w*hen retail load flexibility operates without coordination with ISO-NE, some of its benefit is diluted. Moreover, out-of-market flexibility can only access a limited set of wholesale revenue streams (primarily reduced installed capacity requirement costs). Program administrators and ISO-NE have already begun developing coordination and data sharing practices to improve visibility for retail programs like ConnectedSolutions. These efforts should continue and expand to other retail programs as needed (e.g. EV managed charging, critical peak pricing).

Funding Layer

- *Fund regional benefits through regional markets:* programs that deliver regional benefits should increasingly participate in wholesale markets to provide part of their budget. This would help improve wholesale/retail coordination, avoid issues with parallel dispatch and double compensation, and allow load management programs to scale by reducing reliance on policy charges on bills.
- *Fund local benefits through distribution utility spending:* programs that deliver local benefits (e.g. deferred spending on distribution infrastructure) should receive funding through core utility spending; for example, via a non-wires alternative framework.
- *Consolidate funding mechanisms and regulatory silos:* today, utilities and regulators design, evaluate, and fund load management programs in separate silos (e.g., EV programs in dedicated EV dockets, energy efficiency and active demand response programs in the three-year plans). This makes it challenging to develop a comprehensive portfolio of load management measures, and it results in multiple separate charges on customer bills. Developing strategic

load management plans in a single venue (e.g., as part of each utility's Electric Sector Modernization Plan) could help address this issue.

5.1.2 Energy efficiency and passive load management

Massachusetts leads the nation in passive load management, both for retrofits (through the Mass Save program) and efficient new construction (through the stretch and specialized energy codes). The Technical Potential Study highlights the impact of these measures: 3.7 GW and up to $1.3 billion in annual avoided electric system costs across all modeled passive measures by 2030, and 9.5 GW and $4.9 billion by 2050.[63]

Since the most recent stretch and specialized codes were introduced in 2023, these savings have yet to be fully reflected in load forecasts from Massachusetts utilities and ISO-NE. As Massachusetts residents and businesses build more buildings to these standards, long-term reductions in peak demand should shift these forecasts down, leading to decreased spending on network infrastructure and generation capacity.[64] Accelerating the construction of efficient new buildings will accelerate these grid benefits, in addition to supporting housing affordability goals.[65]

Massachusetts also has a mature market for building energy retrofits, with more than 500,000 homes and small businesses receiving weatherization through the Mass Save program since 2013.[66] These past efforts have already created substantial savings for ratepayers, reducing the peak by nearly 1 GW as of 2024.[67]

Both DOER's Technical Potential Study and the data included in the 2025-2027 Three-Year Energy Efficiency Plan[68] show that there is still an opportunity for further savings from energy efficiency. In addition to continuing to invest in energy efficiency through Mass Save, Massachusetts can explore other policies to accelerate the adoption of retrofits and other load management technologies, particularly in large buildings (where data from large building energy reporting[69] can help diagnose specific bottlenecks). In addition, while the Technical Potential Study identifies substantial cost-effective potential from ground source heat pumps (GSHP),

[63] These cost savings include all modeled passive measures, not just TRC cost-effective measures.
[64] Energy efficiency results in energy savings as soon as it is installed, but the effect on peak load forecasts is delayed, since those forecasts typically rely on a rolling window of recent years.
[65] Accelerating the construction of new housing can also accelerate the development of EV charging infrastructure under the specialized code.
[66] 2013–2023. "Massachusetts Clean Energy and Climate Metrics." Accessed August 8, 2025.
[67] ISO-NE, "2024 CELT Report." May 17, 2024.
[68] See the potential studies in Appendix N.1 – N.6 of the 2025–2027 Energy Efficiency Three-Year Plan.
[69] 225 CMR 27

expiration of federal tax credits for residential GSHP may require Massachusetts to re-evaluate up-front incentives for GSHP to support continued adoption.

Massachusetts can also explore using ground source heat pumps[70] and deep energy retrofits to address specific, acute grid needs. Deep retrofits, which go beyond the package of upgrades offered through Mass Save and often occur during major renovations, can yield thermal performance near that of new construction. While the Technical Potential Study indicates that deep retrofits are not cost effective on a statewide basis, they are a powerful tool for constrained regions of the grid.[71] For example, deep energy retrofits of multifamily buildings could free up space on a constrained circuit to avoid a utility upgrade as a neighborhood transitions from gas to electric heating. Deep energy retrofits may also have targeted benefits for resiliency; for example, upgrading municipal buildings like schools to reduce energy costs and double as cooling or warming shelters during extreme events.

5.1.3 Rate design and time-varying rates

Time-varying rates are the foundation for load management incentives, providing a price signal for customers to manage load every day, using energy when it is cheapest and reducing strain on transmission and distribution infrastructure. Larger C&I customers in Massachusetts already have access to time-varying rates (and demand charges) to encourage peak demand reductions, but residential customers currently have no such incentive.

The Technical Potential Study identifies 0.8 GW of flexible loads in 2030 that can respond to time-varying rates, increasing to 4.3 GW by 2050. Deploying these rates at scale, particularly for residential customers, will help Massachusetts realize $60 million in potential annual savings by 2030, scaling to $2 billion per year by 2050. [72]

The Massachusetts Interagency Rates Working Group (IRWG) investigated the benefits and tradeoffs of advanced rate designs for residential customers in its 2025 Long-Term Ratemaking Study.[73] The IRWG's recommendations include:

- Deploying a default seasonal TOU rate for residential delivery charges (transmission and distribution) and supply through basic service.

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[70] In addition to ground source heat pumps, networked geothermal systems can also provide highly efficient targeted load management.
[71] Technical Potential of Load Management Report at 43.
[72] These cost savings include all modeled active measures, not just TRC cost-effective measures. Many active load shifting measures can be deployed at zero cost (e.g. through behavioral changes rather than smart devices).
[73] MA Interagency Rates Working Group, "Long-Term Ratemaking Recommendations." March 2025.

- Enabling municipal aggregations and other suppliers to offer TOU supply products outside of basic service (with appropriate consumer protection reforms for competitive suppliers).
- Exploring opt-in residential critical peak pricing (CPP) and other advanced rate designs.

Taking these steps as soon as possible following the deployment of AMI by 2028 will help Massachusetts realize the potential of load management and support minimizing electricity costs. In addition to minimizing long-term costs, time-varying rates will also allow consumers to start saving money on "day one," since customers do not need to buy smart appliances or home automation systems to shift their demand and benefit from time-varying rates. As these rates become more widespread, a more mature market for home automation technology will likely develop in Massachusetts, and programs like Mass Save can help customers with the costs of adopting these technologies.[74]

5.1.4 Virtual power plants, aggregations, and active demand management

Demand response and VPP programs provide a powerful complement to TOU rates, providing a signal for customers to reduce load on extreme peak days. This allows customers to maximize their savings while minimizing disturbance, since peak hours are significant drivers of long-term grid infrastructure costs. Practically, peak-shaving programs fill a similar niche as rate designs like critical peak pricing, but they offer a distinct customer experience (i.e. incentive payments rather than penalties under critical peak pricing).[75]

Massachusetts' flagship demand response program is ConnectedSolutions, which aggregates more than 200 MW of flexible load and storage in a statewide virtual power plant. C&I customers already have a choice of two technology-neutral ConnectedSolutions offerings, allowing them to balance compensation with event frequency. These C&I offerings are cost-effective and broadly popular. Residential customers can currently participate in ConnectedSolutions only if they install a battery or a smart thermostat (with an eligible central AC system).[76]

The Technical Potential Study shows that there is a large amount of residential flexibility that is not currently eligible to participate in demand response. Expanding

[74] For example, customers can already buy discounted smart thermostats through Mass Save.
[75] Demand response may also be able to use existing infrastructure (e.g. the edge DERMS currently used for ConnectedSolutions), while CPP may require changes to utility billing systems.
[76] 2025-2027 Energy Efficiency Three-Year Plan at 143.

eligibility through whole-home, technology-neutral demand response programs can help access this potential. The Mass Save program administrators plan to explore AMI-enabled whole-home demand response and behavioral demand response in the 2025-2027 energy efficiency plan term.[77] Pairing technology-neutral incentives with well-designed education and messaging will help ensure that customers can save by reducing their load during peak hours.

Future technology-neutral incentives could also expand to include non-utility VPP offerings from third parties like municipal aggregations. These third parties may be able to bundle load management with reduced supply rates, experiment with new products and aggregation models, and help customers navigate incentives to reduce their energy bills. To support third-party aggregations and VPPs, the state will need to resolve open questions on data access, including data for ISO-NE load settlement, and consumer protections for customers receiving VPP-enabled supply rates.

As these programs scale, they will increasingly affect the bulk power system. As of 2025, energy efficiency program administrators are coordinating with ISO-NE on scheduled demand response events.[78] Once AMI is widely available, retail demand response programs can explore the feasibility of participating more fully in ISO-NE energy and capacity markets, increasing wholesale visibility and potentially accessing new sources of revenue.

5.1.5 EV managed charging & V2X

The Technical Potential Study identifies EVs as the single biggest source of load flexibility, providing 300 GW of capacity in 2030 and 6.5 GW in 2050. These results align with those in the Massachusetts Electric Vehicle Infrastructure Coordinating Council's (EVICC's) Second Assessment, which shows that increasing the use of managed charging can substantially reduce overloads on distribution equipment.[79]

Massachusetts' utilities are beginning to access this potential: National Grid has enrolled 6,000 vehicles in a residential managed charging program,[80] and all three utilities have requested permission to expand (in National Grid's case) or begin offering (for Eversource and Unitil) full-scale residential managed charging

[77] See 2025-2027 Energy Efficiency Three-Year Plan at 144 (whole-home demand response) and 322 (behavioral demand response).
[78] See NECPUC Retail Demand Response and Load Flexibility Working Group.
[79] MA Electric Vehicle Infrastructure Coordinating Council, "Second Assessment to the General Court." August 2025.
[80] D.P.U. 24-196 Exhibit NG-EV-MTM-1 at 23.

programs.[81] The Technical Potential Study shows that scaling EV managed charging for both residential and commercial customers is a no-regrets strategy that merits immediate deployment at scale. The study's scenario analysis shows that these measures remain cost-effective regardless of the pace of EV adoption: as soon as EVs arrive on the grid, there is benefit from managing their load. As the utilities scale these programs, the Technical Potential Study also highlights four areas for special attention.

First, while the utilities' offerings have focused mainly on residential customers so far, the Technical Potential Study finds that medium- and heavy-duty EVs have similar potential for peak load reduction as residential light-duty EVs. While C&I customers have incentives to manage load outside of a managed charging program, a dedicated EV offering for C&I customers may help improve participation rates (e.g., by enrolling customers when they receive incentives for installing EV charging equipment).

Second, both the EVICC's Second Assessment[82] and the Technical Potential Study highlight the value of increasing adoption of vehicle-to-everything (V2X), which provides nearly 150% greater peak reduction on a per-vehicle basis than V1G. To realize the benefits of V2X, Massachusetts utilities will need to:

a) Adopt standards for V2X-capable charger interoperability (to allow utilities to dispatch those assets),
b) Develop a timely process for interconnecting V2X facilities (including scheduled and flexible export limits to minimize interconnection costs), and
c) Develop a program to compensate customers for V2X export and manage V2X dispatch to maximize grid benefits.[83]

MassCEC is currently supporting V2X demonstration projects to explore these challenges in detail; results from these projects will help inform future V2X policies.[84]

Managed charging and V2X can substantially reduce system-level costs, but they can create issues at the distribution level if all EVs in a neighborhood start charging at the

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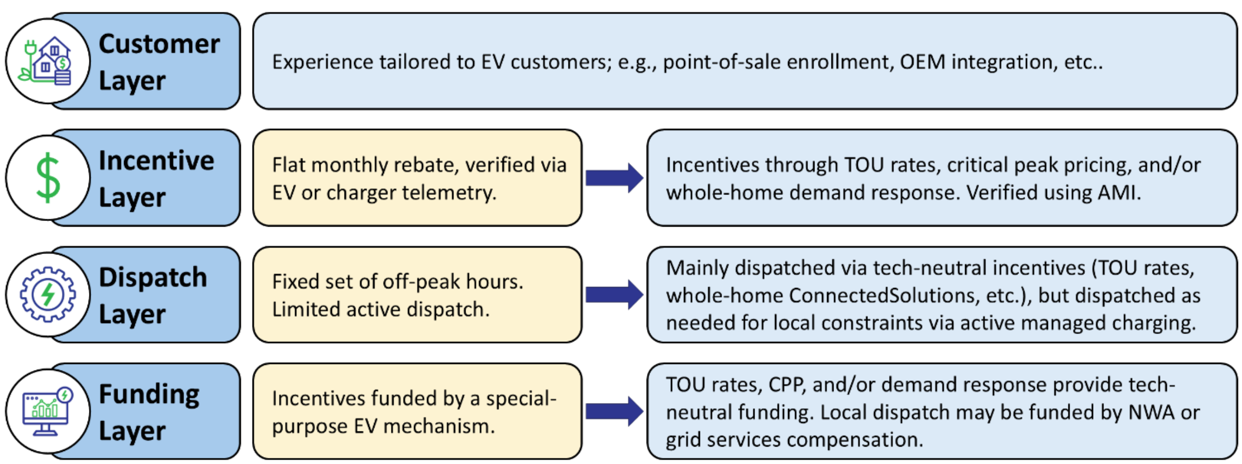
[81] D.P.U. 24-196 Exhibit NG-EV-MTM-1 at 23. D.P.U. 24-195 Exh. ES-EV-MTM-1 at 33; D.P.U. 24-197 Exh. FGE-CCTP-1 at 14.
[82] MA Electric Vehicle Infrastructure Coordinating Council, "Second Assessment to the General Court" at 105-6 and 158.
[83] ConnectedSolutions is designed for behind-the-meter storage that can primarily offset site load during ISO-NE peak events. Because most large-scale V2X facilities will have minimal site load outside of EV charging load, V2X discharge will primarily export to the grid. As a result, V2X facilities may require utility dispatch that respects local distribution grid needs as well as ISO-NE peak events, requiring a program design that is separate from ConnectedSolutions. See D.P.U. 24-195 IR AG-1-6(c).
[84] MassCEC, "Vehicle-to-Everything Demonstration Projects."

beginning of the off-peak window. If utilities do not carefully monitor and actively manage EV load, the cost of distribution infrastructure upgrades could eclipse the system-level savings on capacity and transmission. As the utilities scale their EV offerings, they should carefully monitor local peaks and deploy active managed charging to reduce impacts on the distribution system.

Finally, EV load management programs should evolve as customers gain access to TOU rates and other technology-neutral incentives. Customers with TOU rates will likely not require a separate incentive to shift EV charging. As a result, EV programs can evolve towards helping customers save through their TOU rate rather than providing an independent, separately funded incentive (as shown in Figure 16). EV programs may also evolve to place a larger emphasis on active managed charging to resolve distribution-level constraints and timer peaks, although alternative funding models such as non-wires alternative or grid-services compensation could help reduce the need for a separate funding mechanism.

Figure 16: Evolution of EV managed charging after the introduction of TOU rates.



5.1.6 Water heaters, space heating, and appliance flexibility

The Technical Potential Study highlights the potential of load flexibility from electric water heaters (100 MW by 2030 and 600 MW by 2050). Unlike AC and space heating, electric water heaters come with built-in thermal storage: once hot, a water tank can retain heat through peak hours.[85] As a result, water heaters can shift load without a noticeable change in performance. Moreover, the incremental cost of a demand-

[85] The Technical Potential Study considers electric water heaters with tanks, rather than tankless systems, using load profiles from the Massachusetts ResStock and ComStock models.

responsive water heater is quite low, making these measures low-hanging fruit for demand response. DOER has the authority under the 2024 Climate Act to develop standards for flexible appliances like water heaters, providing a pathway for realizing this potential.[86]

While space heating does not have the same built-in thermal storage as water heating, the Technical Potential Study shows that residential and commercial HVAC[87] flexibility has a cumulative feasible potential of 300 MW by 2050. This estimate accounts for the need to reduce the amount of flexibility in winter to maintain customer comfort and acceptance. As the New England grid transitions to a winter-peaking system in the mid-2030s, heating flexibility can be part of the flexibility portfolio, providing resource diversity that complements flexibility from EVs.

The study also highlights substantial potential from other appliances (200 MW by 2050), including clothes dryers, dishwashers, and refrigerators.[88] The study highlights that the incremental cost of "smart" appliances in these categories is currently too high for them to be cost-effective sources of flexibility, but this cost premium is likely to decrease over time. In the meantime, customers will likely be able to manage these loads *without* automation, so long as they can access appropriate technology-neutral incentives. For example, customers can manually delay running their dishwashers and clothes dryers to save under TOU rates.

5.1.7 Load management for renters, low-income customers, and EJ communities

Through the utility-administered Mass Save program, developed with input from the Energy Efficiency Advisory Committee, Massachusetts has already invested $1.1 billion in energy efficiency improvements for low-income households since 2013.[89] In the current 2025–2027 term, the program administrators plan to spend a further $1.8 billion on equity investments focused on weatherization and heat pump installation for renters and low- and moderate-income households. This represents a dramatic increase in investment in these constituencies.[90]

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[86] Chapter 239 § 32 of the Acts of 2024, *An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers*.
[87] Heating, ventilation, and air conditioning.
[88] On average, a clothes dryer has a peak demand of 2.5—4 kW, a dishwasher peaks at 0.3—1 kW, and a refrigerator peaks at 0.3—0.8 kW (when the compressor is running). See https://www.siliconvalleypower.com/residents/save-energy/appliance-energy-use-chart and https://www.energysage.com/electricity/house-watts/how-many-watts-does-a-refrigerator-use
[89] 2025-2027 Energy Efficiency Three-Year Plan at 3.
[90] D.P.U. 24-140 – D.P.U. 24-149 2025-2027 Three Year Plan April 30, 2025 Compliance Filing at 5.

While these investments will continue to help customers reduce their energy bills and improve health, safety, and comfort, feedback from these communities shows that there are still barriers to equitable access to load management. In both this study, MassCEC's Grid Services Valuation Study,[91] and the most recent Energy Efficiency Advisory Council recommendations for LMI customers and load management[92], stakeholders recommended changes to improve access and equity in load management.[93]

Meaningful engagement: Stakeholders raise concerns that there is a history of disadvantaged communities being left out of decisions that affect their local energy supply. Existing efforts like the Equity Working Group of the Energy Efficiency Advisory Council can help bring equity stakeholders into discussions of statewide program design. Maintaining this engagement will be important to ensure that feedback from EJ stakeholders can help inform the design of new load management programs moving forward. In addition, future efforts can explore ways to empower communities and municipalities to develop locally-designed load management offerings; for example, through municipal aggregations.

Equitable access: Currently, residential customers must install expensive equipment like smart thermostats and batteries before they can participate in demand response or virtual power plants. These technology requirements present a barrier to accessing load management, particularly for renters and LMI customers who cannot install flexible equipment in their homes. Transitioning towards technology-neutral incentives (e.g., time-varying rates and whole-home demand response) would allow any customer to manage their energy costs without an up-front investment. Pairing these programs with focused outreach, engagement, and education can help communities and ratepayers equitably access load management.

Support DER ownership: In addition to ensuring that customers can manage load without an expensive upfront investment, it is also important to support EJ communities in working towards ownership of DERs like storage and measures like deep energy retrofits to build wealth, reduce energy burden, and improve community and environmental health and wellbeing. Several programs in Massachusetts have begun exploring models to support DER ownership, including Generac's project to

[91] https://www.masscec.com/resources/grid-services-study
[92] Massachusetts' Energy Efficiency Advisory Council's Resolution and Priorities for the Development of the 2025-2027 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Investment Plan (March 2024)

support battery ownership for low- and moderate-income households,[94] Cape Light Compact's CVEO[95] offering that pairs solar, storage, energy efficiency, and electrification for low- and moderate-income customers,[96] National Grid's income-eligible VPP offering in its ESMP,[97] and the inclusive utility investment model in the Healey-Driscoll Administration's proposed Energy Affordability, Independence & Innovation Act.[98] As customers receive price signals from TOU rates, opportunities for DERs like storage to help households reduce costs and build wealth will increase.

5.2 Regulatory changes

While load management has the potential to substantially reduce electric sector costs, certain regulatory changes can better ensure that utility incentives are aligned with increased load management. While Massachusetts has relied on various forms of incentive-based regulation since 1994,[99] managing the emerging challenges of widespread electrification and load growth may require new approaches to utility regulation. This section discusses regulatory changes that can help align utility incentives with load management and encourage efficient use and expansion of distribution infrastructure.

5.2.1 Performance incentives mechanisms (PIMs)

Load management can reduce costs by making more efficient use of grid infrastructure. Regulatory tools like performance incentive mechanisms (PIMs) provide a financial incentive for utilities to adopt load management. Table 4 summarizes different types of PIMs related to load management.

Designing an effective load management PIM is challenging because the desire to reduce peak load can conflict with the goal of supporting electrification and economic development (both of which increase load). For example, a peak load reduction PIM may encourage energy efficiency but discourage electrification, although it is possible to design peak load reduction PIMs to consider only the effects of certain programs (as in the performance incentives for energy efficiency

[94] 2025-2027 Energy Efficiency Three-Year Plan at 83.
[95] Cape & Vineyard Electrification Offering.
[96] Olivia Tym, "Solar+Storage+Electrification: A Clean Energy Equity Model For Massachusetts." Clean Energy Group. March 24, 2025.
[97] D.P.U. 24-11 National Grid Future Grid Plan at 342.
[98] Section 52 of the proposed bill.
[99] MA Interagency Rates Working Group, "Long-Term Ratemaking Recommendations." March 2025.

programs[100] or the peak reduction scorecard metrics used by Eversource and Unitil[101]).

Table 4: Potential load management PIMs.

PIM	Pros and Cons
Peak load reduction Reward for reducing peak load below forecast levels.	*Pros:* • Peak reductions directly affect capacity costs. Cons: • Sensitive to peak load forecasts. • May conflict with electrification policies that encourage load growth.
Load factor Reward for improving utilization of grid infrastructure.	*Pros:* • Balances load growth with peak reductions. • Can put long-term downward pressure on rates (see Figure 13). *Cons:* • May have a reduced impact on generation capacity costs if based on non-coincident peak.
Non-wire alternative (NWA) Reward for deploying DERs and load management to defer or avoid investments.	*Pros:* • Incentive can be tied directly to net benefits. *Cons:* • Limited only to regions with NWA projects, rather than system wide.

In contrast, load factor PIMs, which encourage the utility to reduce the ratio between peak and average demand, are more compatible with load growth. By encouraging utilities to sell more electricity during off-peak times, a load factor PIM can encourage electrification (combined with load management to avoid increasing the peak). Load factor PIMs are commonly applied at the substation level,[102] which provides a proxy for how efficiently the system uses major infrastructure (generation, transmission, and

[100] D.P.U. 24-140 through D.P.U. 24-149 Statewide Plan, Exh. 1 at 73-76 and Appendix C: Statewide Data Tables, Exh. 4. The 2025-2027 Energy Efficiency Plan, as approved by the Department, allocates $190 million for performance incentives across all program administrators. Of this statewide total, 50% is allocated to benefits that include peak demand reduction (20% for the "standard" component allocated based on total non-equity benefits and 30% for the "value" component allocated based on net benefits). Because peak load reductions represent less than 10% of the total planned benefits, only a small fraction of the $190 million incentive pool is allocated to the EDCs for peak load reductions.
[101] E.g., D.P.U. 22-22 Order at 91 for Eversource.
[102] NY D.P.S. 20-01611 Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service. Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements.

major distribution assets). Both peak load reduction and load factor PIMs can include the entire system (i.e., the average of all substations) or just constrained regions.

NWA PIMs can complement system-level mechanisms by incentivizing the utility to pursue net-beneficial opportunities to defer or avoid infrastructure upgrades using DERs or load management. These PIMs are typically structured as benefit-sharing mechanisms in which the utility receives a portion of the assessed benefits from its NWA projects, which can help counteract utilities' bias for capital expenditure.

Other jurisdictions have explored all three of these incentives. For example, National Grid's New York affiliate included PIMs in its 2021 rate case covering peak reduction relative to New York Independent System Operator peak forecasts, load factor improvements in constrained regions, and benefit sharing from NWA projects.[103] In Massachusetts, Eversource and National Grid have scorecard metrics (which do not include a financial incentive) for peak demand reduction,[104] and National Grid plans to propose an NWA incentive mechanism following the Electric Sector Modernization Plan (ESMP) proceeding.[105]

Moving forward, Massachusetts can explore adopting load management PIMs, particularly for load factor and NWAs, as these are most complementary with the Commonwealth's electrification goals. Developing new PIMs will require action from the DPU and substantial engagement with utilities and other stakeholders, and the Massachusetts Electric Rates Task Force is exploring these issues as part of a comprehensive discussion of utility regulation and ratemaking in Massachusetts.[106]

5.2.2 Other regulatory changes

In addition to load management PIMs and time-varying rates, three other potential regulatory changes have important implications for load management.

First, utilities currently receive a rate of return on capital investments ("capex"), while operational expenses ("opex") are typically passed through to customers without earning a return. This creates a disincentive for utilities to integrate NWAs and load management into their planning process, since NWAs can replace certain large capital expenses with programs that require operational expenses. Investigating regulatory models that allow certain operational expenses to earn a return (e.g.

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[103] NY D.P.S. 20-01611 Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service. Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements.
[104] MA Interagency Rates Working Group, "Long-Term Ratemaking Recommendations" at 52 (2025).
[105] D.P.U. 24-11 Exhibit NG-1 at 30.
[106] https://www.mass.gov/info-details/massachusetts-electric-rate-task-force

through "capex-opex equalization" mechanisms) may help encourage investment in NWAs and load management.

Second, there is a connection between load management and revenue decoupling. Revenue decoupling is a regulatory mechanism that guarantees each utility will receive its required and approved level of revenue, regardless of the amount of electricity it sells in a year. The DPU initially adopted full revenue decoupling mechanisms in 2008 to incentivize utilities to support energy efficiency.[107] While decoupling was appropriate in a period of flat or declining load growth, in 2022 the DPU found that the adoption of strategic electrification as a core goal of the energy efficiency plans "obviates the need for the continued use of revenue decoupling."[108] To date, no investor-owned distribution utility has proposed removing its decoupling mechanism, but doing so may provide an added incentive for load management, since utilities could then increase their revenue by supplying more electricity during off-peak hours (especially if recoupling were paired with a load management PIM).

Third, utilities fund many load management programs using special purpose reconciling mechanisms (e.g., the electric vehicle charge), and regulators evaluate these programs in separate proceedings. Moving forward, Massachusetts can explore developing an integrated distribution system planning (IDSP) framework to consolidate grid planning and cost recovery. Integrating load management more fully into utility planning, through a process like IDSP, can help ensure that ratepayers receive the full benefit from load management and energy efficiency efforts.

5.3 Legislative recommendations

In March 2025, the Healey-Driscoll Administration filed a proposal for an Energy Affordability, Independence & Innovation Act (EAII),[109] which includes several load management provisions that align with the strategic principles in this report. For example:

- *Aligning load management with grid needs:* Section 29 of the EAII would require Massachusetts utilities to develop comprehensive load management plans to maximize benefits to ratepayers.
- *Consolidating costs and aligning utility incentives:* Section 30 of the EAII would require the DPU to, among other things, consolidate planning and cost recovery proceedings and investigate new incentive mechanisms.

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[107] MA Interagency Rates Working Group, "Long-Term Ratemaking Recommendations" at 43 (2025).
[108] D.P.U. 21-120 through 21-129-A, Order at 227 (2022).
[109] See the Governor's filing letter and bill text for An Act relative to energy affordability, independence, and innovation.

- *Reducing up-front barriers to adopting DERs:* Section 52 of the EAII would require Massachusetts utilities to offer "pay as you save" on-bill financing of energy projects, including DERs and demand response equipment.

In addition to these provisions, which focus on demand-side flexibility and load management, the proposed legislation also includes provisions for supply-side flexibility through flexible interconnection (FI),[110] which allows DERs to dynamically adjust their behavior to minimize their impact on the grid and the need for new infrastructure.

Together, these proposals remove barriers to scaling load management and ensure that the savings from load management translate to reduced bills for Massachusetts ratepayers.

5.4 Technology recommendations

Most of the potential for load flexibility is available using existing, proven technologies, although not all these technologies are widely deployed yet in Massachusetts. However, there are areas where new technologies can help customers manage flexible loads, reducing friction and improving participation, or reduce the cost of efficient appliances. There are also areas where utility investments can enable more load flexibility. This section discusses these issues and provides recommendations to guide future technology development.

5.4.1 Customer technology

Customers do not need to adopt new technologies like smart appliances or energy management systems to benefit from future technology-neutral load management programs in Massachusetts. However, there are opportunities for technologies to complement load management programs and help customers manage flexible loads. For example, while customers can change their behavior in response to TOU rates, home automation technologies and smart appliances can help make this response easier. While Massachusetts should continue to support the adoption of technologies like automation for customer energy management,[111] it is important that these tools not become prerequisites to scaling load management through broadly accessible technology-neutral incentives like TOU rates. In fact, Massachusetts may need to provide these price signals before a robust market for energy management tools can develop, particularly among residential customers. As this market develops, policymakers and industry partners should look for opportunities to develop low-cost,

[110] *Ibid* § 159.
[111] For example, Mass Save provides discounts for ConnectedSolutions-eligible smart thermostats.

easy-to-use load management tools; for example, systems that make real-time data from smart meters available on customers' phones, allowing them to make load management decisions without installing smart equipment.

5.4.2 Utility technology & AMI

The current lack of smart meters for residential and small commercial customers in Massachusetts is the primary roadblock for scaling load management beyond passive energy efficiency. Without a smart meter (and supporting utility software), customers can neither receive credit for reducing their peak demand nor participate in aggregations like VPPs. With this constraint, load management programs cannot scale beyond narrow offerings with strict technology requirements (e.g. battery-only demand response).

Massachusetts utilities are in the process of deploying AMI, but these meters will not be fully available statewide until 2028 (although some distribution utilities will finish their deployment earlier). In the interim period before AMI is fully deployed, utilities, policymakers, and program administrators should focus on running pilots and evaluating future program design so that load management programs are ready to scale when meters are available.

As the utilities continue their AMI deployment, utility regulators can work to ensure that the software supporting these meters will be capable of enabling load management: for example, by settling load data in ISO-NE markets, providing near real-time data access for aggregators and suppliers, providing customers with visibility and control over their energy usage, and using DERMS to communicate with flexible devices. Utilities, policymakers, and aggregators should be prepared to "hit the ground running" with innovative load management offerings as soon as possible following the deployment of AMI.[112]

While waiting for full AMI deployment, Massachusetts should also aggressively pursue new load management in applications where a smart meter is *not* needed, most notably for EV managed charging.[113]

5.4.3 Regulatory sandboxes

Utilities and aggregators can deploy many forms of load management at low cost using existing, mature technologies. However, there may still be opportunities for

[112] For example, by proactively discussing issues around load settlement and data sharing, as D.P.U. has done through recent technical sessions in 21-80/81/82.
[113] In addition to EV managed charging, existing residential ConnectedSolutions offerings do not require a smart meter because they rely on either average performance (for central AC) or meters embedded in appliances (for storage).

advanced load management tools to help simplify the customer experience and improve the performance and reliability of load management. To support the development and adoption of advanced technologies, jurisdictions like Connecticut have experimented with "regulatory sandboxes", programs that provide funding and regulatory support for utilities to partner with third parties to deploy innovative grid solutions.[114] While several channels might support such pilots, sandbox programs are unique in providing a clear path to full-scale deployment for innovative grid solutions. Massachusetts can explore ways to pair and expand its existing grant programs for technology development (e.g. the suite of technology-to-market programs[115]) with a supportive regulatory framework for utility technology adoption.

5.4.4 Cost reductions

The Technical Potential Study highlights several areas where future reductions in cost could unlock substantial load management potential; for example, from smart appliances and behind-the-meter storage. The potential for new technologies to become cheaper and more cost-effective as market conditions change underscores the need for technology-neutral incentives that can adapt accordingly. By developing incentives to support load flexibility, Massachusetts and other states can support economies of scale to drive down future costs for technologies like storage and V2X.

There are also opportunities for focused technology development efforts at the state level to reduce the cost of ground source heat pumps (GSHP) and deep energy retrofits. Based on the cost-benefit model from the Technical Potential Study, reducing the net cost of deep energy retrofits by $5,000 per kW-year could make these measures cost-effective.[116] GSHP are already cost-effective based on the Technical Potential Study, but up-front costs remain a barrier to customers considering GSHP. In both areas, grant funding and workplace development efforts could help support market development and cost reductions at scale.

[114] Connecticut Innovative Energy Solutions program
[115] https://www.masscec.com/masscec-funding/technology-market
[116] This net cost reduction could come from either reduced material and installation costs for deep retrofits, or increased benefits in constrained areas of the electrical grid where retrofits can allow for distribution investment deferral.

6 Next Steps

DOER invites public comment on this report and its recommendations until February 9th, 2025. Please submit comments via email to Charles Dawson, Energy Innovator Fellow at DOER: charles.dawson@mass.gov. DOER welcomes general comments on the report and recommendations as well as specific comments on the following:

- Standards adopted or under consideration in other jurisdictions for flexible equipment, particularly for heat pumps, window AC units, and EVSE.
- Opportunities to reduce customer supply rates using load management, particularly for municipal aggregations.
- Best practices for customer education, outreach, and marketing for load management programs.
- Incentives or other models to support adoption of load management technologies, including energy efficiency and behind-the-meter storage, for low- and moderate-income customers.

Appendix A: Existing Load Management Programs

Table 5: Load management options for residential customers.[117]

Program	Eligibility	Description
Mass Save (Passive load management)	All ratepayers, with extra incentives for low- and moderate-income customers and renters.	Provides free home energy assessments, low- or no-cost air sealing and insulation, and rebates on efficient equipment.
Energy Codes (Passive load management)	Required for all new buildings and major renovations.	More than 90% of residents live in communities that have adopted the stretch or specialized codes, which substantially reduce the heating and cooling loads from new buildings.
ConnectedSolutions (Battery Storage)	Must have an approved storage system.	Provides a $275 / kW incentive for battery discharge during peak events. Customers can opt out of events, but this will decrease the incentive.
ConnectedSolutions (Smart Thermostats)	Must have an approved thermostat and central air conditioning.	Provides a flat $20 annual payment for participation. Customers can opt out without reducing their incentive. No metering or performance measurement, which increases the risk of shifting costs to non-participants.
EV Managed Charging	Must have an approved EV or charger. Only offered by National Grid as of 2025.	Provides a rebate for customers who charge during off-peak times, verified by either the EV or charger.

Table 6: Load management options for large C&I customers.[118]

Program	Eligibility	Description
Mass Save (Energy Efficiency)	All customers.	Provides incentives for rebates on efficiency measures for commercial buildings.
Energy Codes (Energy Efficiency)	Required for all new buildings and major renovations.	More than 90% of residents live in communities that have adopted the stretch or specialized codes, which substantially reduce the heating and cooling loads from new buildings.

[117] All incentive levels and program details as of Summer 2025.
[118] All incentive levels and program details as of Summer 2025. Large C&I customers can also participate in demand response under the Clean Peak Standard, but it represents a smaller incentive than ConnectedSolutions and demand charge management for most customers. Large C&I customers can also participate in ISO-NE markets, as discussed in Table 7.

ConnectedSolutions	All customers.	*Daily dispatch:* Provides a $200 / kW incentive for load reduction in up to 60 two- to three-hour events. *Targeted dispatch:* Provides a $30 / kW incentive for load reduction in up to eight three-hour events. Both options are technology-neutral and pay based on performance during peak periods.
Time-of-use Rates	G3 customers (and others with third-party supply).	Provides a discount for electricity consumed during off-peak hours.
Demand Charges	G2 and G3 customers.	Customers pay based on their peak demand. Some rates include an option to be charged based on coincident peak demand, and some differentiate between demand during on- and off-peak periods.

Table 7: Load management in ISO-NE markets.

Program	Eligibility	Description
Energy Markets	Active DRRs with interval metering.	All customers on supply contracts with wholesale pricing can reduce their load in response to day-ahead and real-time price signals. Customers that participate as DRRs can also bid into the ISO-NE energy market and be dispatched by the ISO. DRRs with a capacity supply obligation must offer energy bids.
Reserve Markets	Active DRRs with interval metering and real-time telemetry.	Energy and reserves are jointly optimized in the ISO-NE market, but DRRs are only eligible to provide reserves if they provide real-time telemetry to ISO-NE.
Capacity Markets	Active DRRs with interval metering, or passive demand reduction resources with appropriate verification.	Active DRRs can receive a capacity supply obligation as part of an active demand capacity resource. Passive load management (e.g. energy efficiency) can offer capacity as part of an on-peak or seasonal-peak capacity resource.