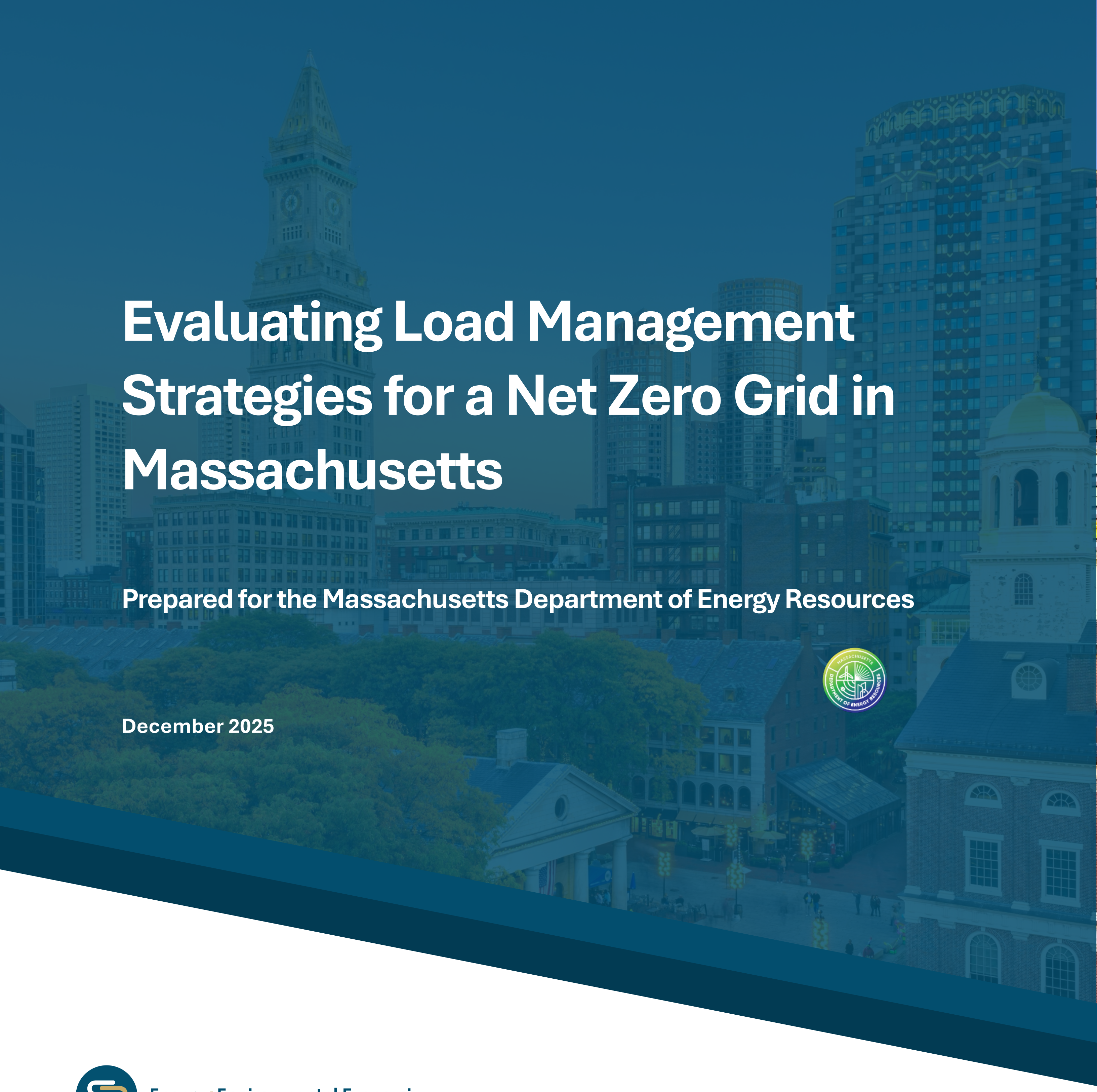

Evaluating Load Management Strategies for a Net Zero Grid in Massachusetts

Prepared for the Massachusetts Department of Energy Resources

December 2025

Energy+Environmental Economics

Authors and Acknowledgements

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Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. E3's analysis is utilized by the utilities, regulators, developers, and advocates that are writing the script for the emerging clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

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With support from:

Applied Economics Clinic Based in Massachusetts, the Applied Economics Clinic (AEC) is a mission-based non-profit consulting group that offers expert services in the areas of energy, environment, consumer protection, and equity from seasoned professionals while providing on-the-job training to the next generation of technical experts.

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For this study, AEC supported E3 by leading the development of resiliency and equity impacts and managing the advisory group and stakeholder sessions.

Acknowledgements

This study was sponsored by the Massachusetts Department of Energy Resources, who provided valuable guidance, input and certain assumptions for the analysis. The specific assumptions provided by DOER are noted within the report body.

MA DOER Study Partners: Charles Dawson, Aurora Edington, and Jerrylyn Huckabee.

Stakeholder Advisory Group:

This study received helpful feedback from an expert advisory group comprised of individuals from state agencies, electric utilities, consumer advocates, environmental advocacy organizations, and industry. The study authors are grateful to the members of this group for their thoughtful feedback and participation throughout the study. We note that members of the Advisory Group were not asked to endorse final results, and all report conclusions remain our own.

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Executive Summary

Motivation

To address the risks posed by climate change, Massachusetts is pursuing a path to Net Zero emissions, as directed in the Global Warming Solutions Act of 2008. Meeting this target will require significant electrification of buildings and transportation, potentially more than doubling statewide electricity demand, as explored in the Climate and Clean Energy Plan (CECP) studies.[1] At the same time, the Commonwealth may need over 50 GW of new renewable generation to fully decarbonize the power sector, depending on how much load growth takes place in the Commonwealth and how effectively the region can manage that load growth. These dramatic changes to both electric supply and demand create new challenges and opportunities, requiring careful planning to ensure that growing electric load can be integrated into the grid affordably and reliably.

Load management, employed by shifting, shaping, or reducing electric loads, will be an important strategy to achieve this aim. Specifically, by helping align the timing of electricity demand with clean energy supply, for example by using behind-the-meter (BTM) energy storage or leveraging electric vehicle (EV) charging as flexible demand, Massachusetts can reduce electric system costs and increase utilization of renewable generation. Load management can also help limit demand during peak periods, reducing the need for new infrastructure investments in generation, transmission, and distribution capacity.

Study Objectives

On behalf of the Massachusetts Department of Energy Resources (DOER), E3 prepared this assessment of Massachusetts's load management potential in futures aligned with deep decarbonization and the Commonwealth's CECP goals. With direction and input from DOER, this study had three primary aims:

- Evaluate a **technical potential scenario** for load management in the Commonwealth in 2030, 2040, and 2050, under a clean energy technology adoption pathway consistent with CECP 2050, establishing the total load management potential in this future before accounting for costs and program participation.
- Conduct an economic analysis to estimate the **costs and benefits** of different load management strategies.
- Assess **feasible potential scenarios** for load management in the Commonwealth in 2030, 2040, and 2050, considering two scenarios with differing levels of load growth and load management assumptions.

[1] Massachusetts Clean Energy and Climate Plan for 2050 | Mass.gov

Approach

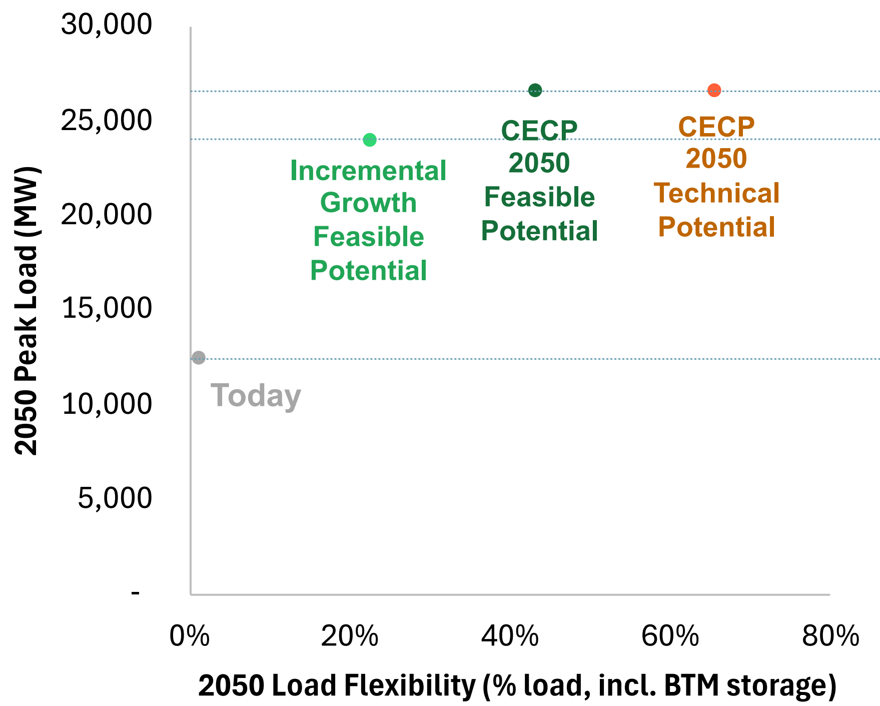
This study evaluates how load management strategies can reduce peak demand in 2030, 2040, and 2050. There are two types of measures included in this study – **passive** measures, which reflect high-efficiency devices and infrastructure improvements that reduce energy use year-round, and **active** measures, which shift and shed loads when the benefits of doing so are highest for the electric system.

To determine when to move loads, E3 identified high-value periods, termed "critical hours," in which the grid was most constrained, and the risk of loss-of-load is highest. In these hours, decreases in consumption yield the greatest avoided electric system costs, as described further in the Critical Hours Framework section. The most critical hours for moving load evolve over time. As electrification accelerates, Massachusetts is expected to transition to a winter-peaking grid, shifting critical hours from summer evenings in 2030 to winter evenings and mornings by 2050. In addition to the periods of critical hours changing by mid-century, the duration of grid-constrained periods is also likely to increase, with longer, potentially multi-day, stretches of sustained high demand and low renewable output.

E3 modeled two "feasible potential" scenarios, which differ in the adoption of electric vehicles and heat pumps, with the Incremental Growth scenario drawing from ISO New England's 2025 Capacity, Energy, Loads, and Transmission (CELT) forecasts, and the CECP 2050 Growth scenario adoption aligning with the CECP 2050 Phased scenario. The Incremental Growth scenario reflects a more conservative view of load management participation and enabling technology uptake, while the CECP 2050 Growth scenario assumes greater participation and load management technology adoption. The two scenarios show a range of peak reduction and avoided cost outcomes across the dimensions of load growth and flexibility, enabling electric system planners to better understand load management potential across different technology adoption futures.

ES Figure 1 shows the load growth and flexibility assumptions used in this study across scenarios.

ES Figure 1. Load Growth and Management across Scenarios



Notes: Load flexibility % value shown here reflects total load shifted or shed (including via BTM storage) in the top 200 critical system hours (roughly matching the top 200 net load hours), as a share of total net load in those hours, net of efficiency measures. Both CECP and Incremental Growth scenarios assume significant increase in EV and building loads by 2050. Peak load shown is for Massachusetts only, and is unmanaged, i.e., the peak loads shown do not include the impacts of load management measures.

This study uses weather-matched load and renewable profiles aligned with typical weather conditions, building up bottom-up gross and net loads by end use. To model load flexibility, this study leaned on measure-level flexibility estimates from various sources. For building sector measures, the Lawrence Berkeley National Laboratory's California Demand Response Potential Study, Phase 4 (May 2024), provided estimates of load shift and shed capabilities as a share of gross load across different time periods (e.g., 1-4 hours). For EV charging management measures, this study utilized unmanaged and managed load shapes developed for the Executive Office of Energy and Environmental Affairs (EEA) in support of the Electric Vehicle Infrastructure Coordinating Council (EVICC).

This analysis combined the load shape data with the 2024 Avoided Energy Supply Costs in New England (AESC), which provides hourly marginal electric system supply and delivery costs, and with several different cost data sources. The analysis reports individual measure cost-effectiveness under a total resource cost (TRC) perspective, comparing state-level avoided electric system costs and emissions to incurred capital costs and administrative utility program costs, and reporting aggregate net benefits for each scenario.

Key Findings

The analysis demonstrated the growing potential for load management in the Commonwealth, and established key findings related to its costs, benefits, and feasible potential under different future scenarios. These findings are summarized below.

Key Finding 1: Strategies to manage load may collectively deliver significant electric demand reductions in the Commonwealth. Passive load management, such as cold-climate heat pumps and building shell improvements, can avoid 2.7 to 3.7 GW by 2030 and 8 to 9.5 GW by 2050. Active load management, such as EV charging management, building load flexibility, and BTM storage, can further flatten peak demand by 300 to 800 MW by 2030 and 2.3 to 4.3 GW by 2050.

Passive load management, primarily building efficiency measures, can provide electric grid savings and emissions reductions year-round and reduce the overall load management need. The study found that building efficiency measures delivered significant energy and capacity savings while advancing the Commonwealth's building decarbonization goals. Cold-climate air source heat pumps, ground source heat pumps, and hybrid heat pumps utilizing existing non-electric gas backup, help limit peak demand growth from buildings relative to standard air source heat pumps. Building shell retrofits and high-performance new construction via opt-in municipal stretch building energy codes further reduce building thermal load.

Active measures reduce peak demand by targeting critical hours of high load or limited renewable generation through load shedding and shifting technologies across various end uses. Key measures include managed electric vehicle charging and vehicle-to-grid dispatch, which together account for roughly two-thirds of active peak reduction across feasible potential scenarios in 2050. BTM storage, space and water heating load shifting, and industrial demand response, which shift or reduce demand during targeted hours, account for the remaining third of active peak reduction in 2050 across feasible scenarios. For each measure, estimated peak reduction is based on technology adoption assumptions for each scenario, as well as the order in which they are dispatched, given that shifting technologies compete to move the same loads and are thus substitutable.

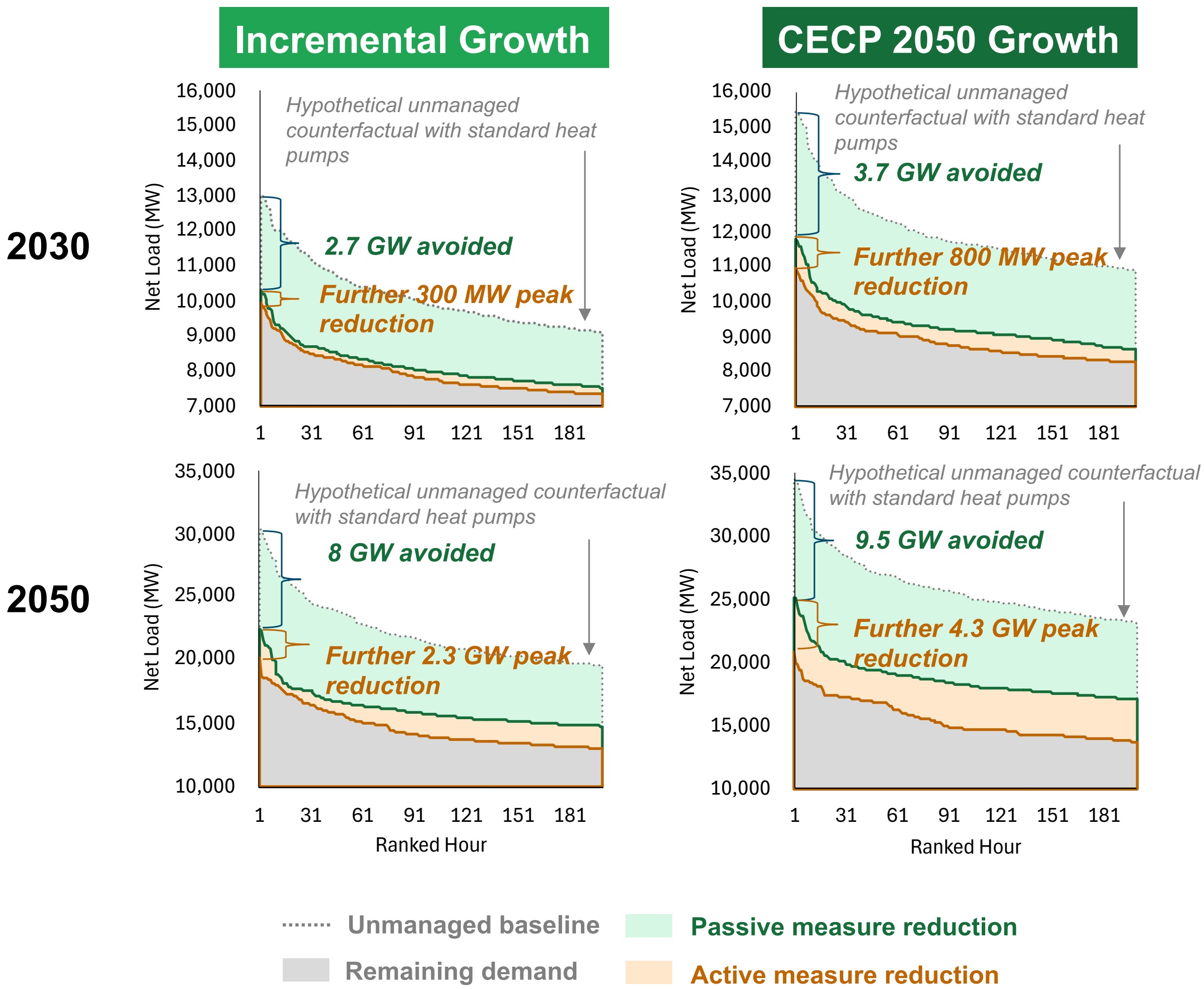
More broadly, as measures are dispatched and net peak demand flattens, additional load shifting yields diminishing returns, requiring longer dispatch periods for equivalent reductions. Future more detailed study of the dependability and effective load carrying capability of these demand-side strategies is needed to assess their contributions to resource adequacy.

ES Figure 2 shows the net peak reduction achieved by load management measures across scenarios that vary peak demand growth and flexibility. In the Incremental Growth scenario, which leans on ISO-NE[2] electrification trajectories and more limited flexibility assumptions, passive measures avoid 2.7 GW of peak demand by 2030, and 8 GW by 2050, relative to futures using standard air source heat pumps without any further building shell improvements. These peak load reductions translate to 21% and 26% of counterfactual peak demand net of renewable generation in 2030 and 2050 respectively. Active load management achieves 300 MW of net peak reduction by 2030, and 2.3 GW by 2050, translating to 3% to 10% of remaining net peak demand respectively. In this scenario,

[2] ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) 2025

active and passive load management together can reduce gross peak demand by 20% in 2030 and 30% in 2050.

ES Figure 2. Aggregate Load Reduction in Critical Hours across Modeled Scenarios



The CECP Growth scenario, aligned with electrification adoption from the CECP 2050 Phased Scenario and higher flexibility participation, shows passive measures avoid 3.7 GW of peak demand by 2030, and 9.5 GW by 2050, relative to futures utilizing standard air source heat pumps without additional building shell improvements. This translates to 24% to 27% of net peak reduction by 2030 and 2050 respectively. Active measures flatten peak demand by 800 MW by 2030 and 4.3 GW by 2050, translating to 7% to 17% of net peak respectively. In this scenario, active and passive load management together can reduce gross peak demand by 24% in 2030 and 30% in 2050. In addition to shifting periods of EV charging (V1G), this scenario increases adoption of vehicle-to-grid (V2G) integration, or bidirectional charging, in which EVs discharge electricity back to the grid during peak periods. This capacity could provide significant additional grid support and energy balancing; however, V2G is still in an early commercial phase and requires bidirectional chargers, vehicle compatibility, and utility interfaces, and its deployment is likely to depend heavily on coordinated utility, ISO-NE, and state policy support.

Key Finding 2: Across feasible futures aligned with the Incremental and CECP 2050 Growth pathways, passive load management measures could avoid $4.0–$4.9B in annual electric system costs in 2050. Active measures could avoid $700M–$2.0B in 2050.[3] EV charging management, cold-climate heat pumps, and stretch codes for new construction provide the greatest net benefits from measures analyzed. When focusing only on measures that provide net benefits, total avoided electric grid costs reach $3.1-$4.8B in avoided costs in 2050, with $7-$9.1B in total resource cost net benefits.

Passive load management measures can deliver significant year-round energy and emissions savings, especially in the near-term where fossil generation is the marginal supply resource. Active load management strategies that target peak reduction during critical system hours can avoid electric generation capacity, transmission system, and distribution system costs.[4,5]

ES Figure 3 shows the relative lifetime TRC cost-effectiveness of passive and active measures installed in 2030. As shown in this figured, TRC cost-effectiveness includes different avoided electric system cost components, avoided emissions, incurred capital costs, and incurred utility administrative costs. Over the lifespan of these devices, the electric system transitions from summer peaking in the early 2030s to winter peaking by 2050, driven by widespread heating electrification as explored in the Critical Hours Framework section. Among passive measures, cold-climate heat pumps and stretch codes for new construction are cost-effective approaches to limit peak demand growth from building electrification. Among active measures, EV charging management is the most cost-effective measure examined. Grid-enabled hybrid heat pumps and V2G are also cost-effective strategies.[6] This study applied a Total Resource Cost (TRC) metric, comparing the lifetime benefits from load management, including avoided electric system costs and greenhouse gas emissions, to capital and operating costs. Over time, avoided costs tend to decrease, due to assumed decreasing electric capacity costs and decreasing avoided emissions due to the decrease in carbon intensity of grid electricity. Future generation capacity and emission costs are key inputs for determining measure cost-effectiveness in the future and are subject to uncertainty.

While some measures come with high upfront capital costs, total avoidable electric system costs in the scenarios modeled in this study are significant. Across the Incremental and CECP 2050 Growth pathways, passive load management measures could avoid $1.0–$1.3B in annual electric system costs in 2030, and $4.0–$4.9B in annual electric system costs in 2050, while active measures could avoid $20M–$60M in 2030, and $700M–$2.0B in 2050. Focusing on only those measures with net TRC benefits, i.e., benefits greater than costs, we find avoidable electric system costs on the order of

[3] Prior to considering program incentive costs.

[4] This study used the 2024 Avoided Energy Supply Costs in New England (AESC) as a data source for marginal electric system supply and delivery costs, and several different sources, described within, to estimate capital and operating costs for load management strategies.

[5] This study includes a simplified approach to estimating average distribution system avoided costs; a geographically disaggregated range of locational benefits of load management strategies was outside this study scope but is explored in the MassCEC Grid Services Study. Available at https://www.masscec.com/resources/grid-services-study.

[6] This study did not include avoidable gas distribution system costs from all-electric heating strategies. These costs are a topic of ongoing study (e.g., in the D.P.U. 20-80 docket) and could yield added costs savings for all-electric heating strategies relative to hybrid heat pumps with natural gas backup heating that require the continued operation and maintenance of the gas distribution system.

$650M to $950M in 2030, and $3.1B to $4.8B in 2050 across the Incremental Growth and CECP 2050 Growth scenarios respectively. After including capital costs (reduction) and emission reduction benefits (positive), net TRC benefits for these measures are $3.9B to $4.4B in 2030, and $7B to $9.1B in 2050.

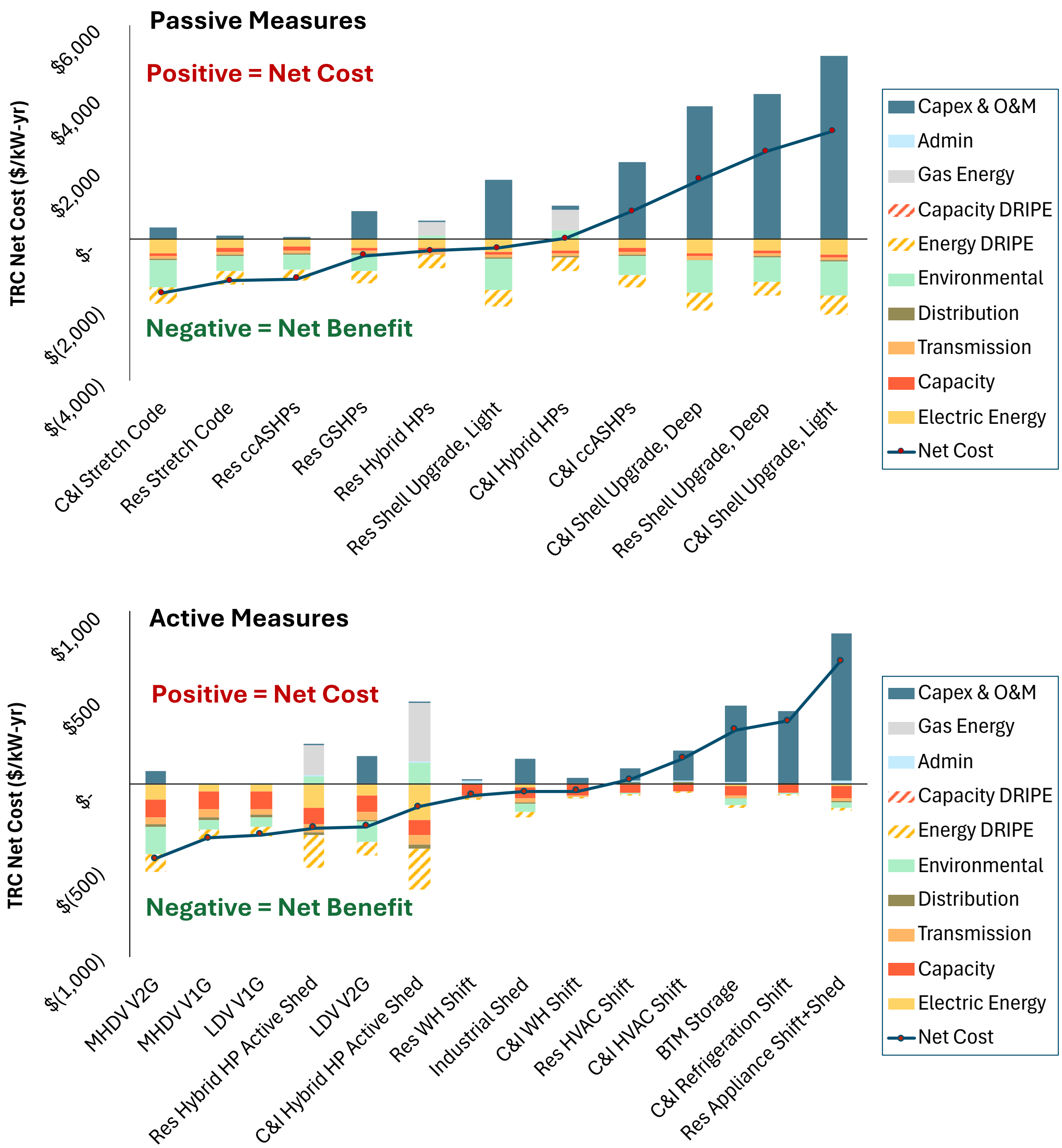
Most of the peak demand avoided by passive measures can be attributed to the efficiency gains of cold-climate heat pumps and stretch energy codes for new construction. These measures reflect existing policy and programs; Mass Save already requires cold-climate certification and building weatherization for air source heat pump rebates, and stretch and specialized energy codes for new construction have already been adopted by ~90% of the population of the Commonwealth.[7] While cold-climate heat pumps are already the default heat pump assumed in existing electric system planning, stretch codes were not modeled in the ESMPs. Thus, the additionality of peak reduction from passive measures in this study depends on the efficiency of technologies assumed in baseline load growth, which varies across state and utility load forecasts.

As mentioned above, load shifting technologies may compete to manage the same loads, particularly for smaller peaks that can be 'clipped.' For example, from a system planner's perspective, an electric vehicle's charging load in peak hours can be shifted directly by the vehicle owner, by a customer-sited battery storage system, or by a utility-scale battery storage system. Utility programs that remain technology-agnostic and encourage and incentivize the most cost-effective demand-side management strategies can ensure maximum societal and ratepayer benefits.

Another caveat is that significant changes in load often trigger changes in marginal grid resources and infrastructure costs. As part of future research, avoided cost estimates derived by applying a marginal cost framework to large load reductions should be evaluated through capacity expansion modeling to capture the complete impact on electric system costs.

[7] https://www.acecma.org/wp-content/uploads/energy-building-code-adoption-by-municipality-map-and-list.pdf

ES Figure 3. Levelized Lifetime Incremental Total Resource Cost of Measures, 2030



Notes: Levelized lifetime NPV incremental total resource costs, including upfront costs, avoided electric system costs, administrative costs, environmental benefits per kW critical hour (top 200 hours) load reduction, over device lifetime. Note that in 2030, the system is summer peaking. DRIPE = demand reduction induced price effect. LDV = light duty vehicles. MHDV = medium and heavy duty vehicles. Res = residential. C&I = commercial and industrial. GSHPs = ground source heat pumps. ccASHPs = cold-climate air source heat pumps. HPs = heat pumps. WH = water heating. HVAC = heating, ventilation, and air conditioning.

Key Finding 3: Load management has the potential to create equity and resiliency impacts that improve outcomes for disadvantaged communities, when paired with careful program design.

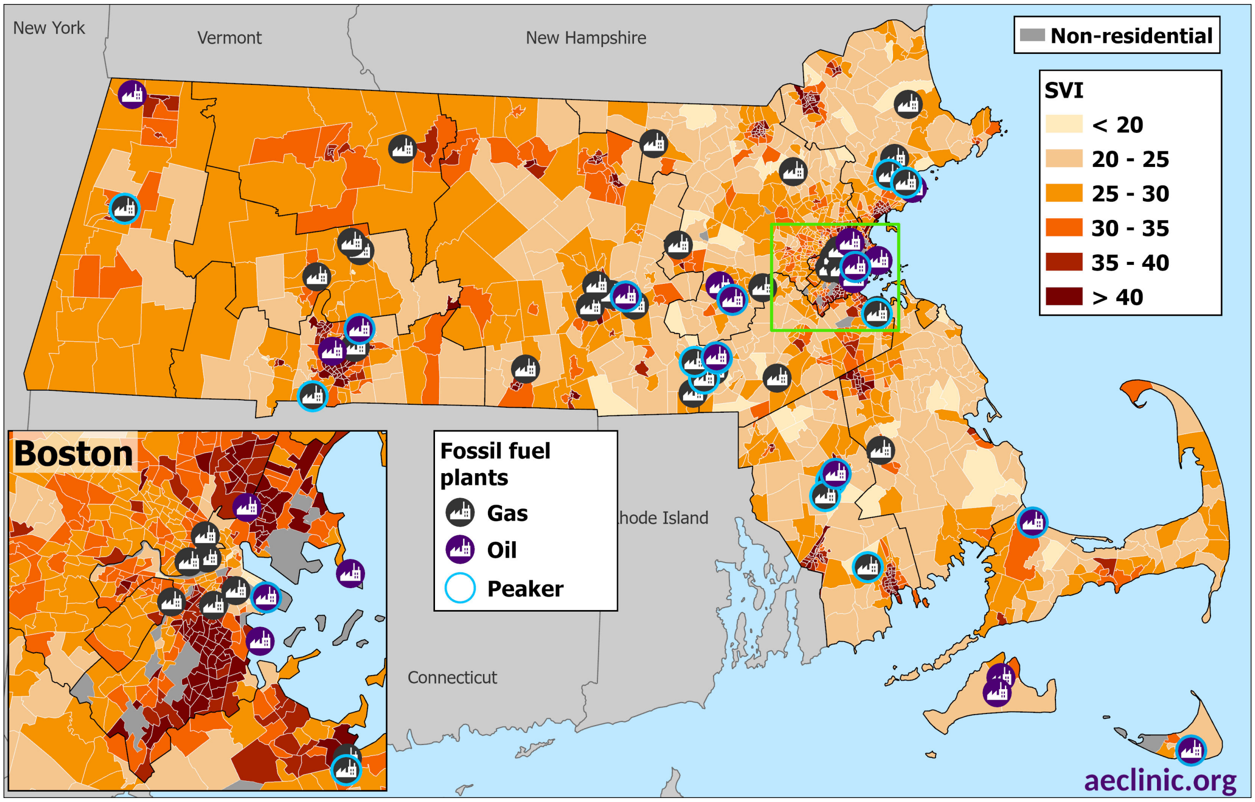
Load management could provide equity and resiliency benefits, including avoided outages, enhanced building-level resilience, reduced environmental pollution, increased job creation, and reduced energy burden. Disadvantaged communities that face outsized challenges in these respects can benefit from programs that consider and prioritize equity in their design and implementation.

ES Figure 4 shows a map of the social vulnerability index (SVI) of different communities in Massachusetts. As explored in the Social Vulnerability Index Analysis section, AEC developed this metric to measure communities' relative socioeconomic vulnerability. The SVI combines values from ten measures of vulnerability, including measures of socioeconomic vulnerability and housing vulnerability (see Table 7).[8] A higher SVI score indicates multiple, overlapping vulnerabilities. For example, communities that have a high share of low-income households, Black, Indigenous Peoples, and People of Color (BIPOC) households, households with limited English language proficiency, renter households, and energy-burdened households. Disadvantaged households also face particularly steep barriers to adopting both electrification and load management resources due to factors such as high upfront cost barriers and limited agency in rental housing units. For example, these customers may lack access to affordable upfront financing for household BTM energy storage systems or may live in neighborhoods with limited EV-charging availability. SVI analysis can help to identify communities that have disproportionate socioeconomic burdens and challenges to adopting load management technologies, and thus better enable targeted approaches in program design to ensure that these communities are able to see positive economic benefits (e.g., lower electricity bills) and resiliency impacts (e.g., reduced outages) from load management programs.

An important consideration in load management program design will be avoiding regressive cost shifts, i.e., raising bills for non-adopting customers that may have lower incomes and a more limited ability to shift load. This could arise in circumstances with disproportionate uptake of load management incentives among higher-income households and rate and program design that is misaligned with utility costs. If rate and program designs involve program costs and reduced utility collection that exceed utilities' avoided costs from load management, non-participating ratepayers must then make up the difference and face higher bills. Default, opt-out, time-varying rates, could also lead to a shift in cost recovery to lower-income households with limited ability to adopt technologies to move loads. Thus, rate and program designs must ensure that ratepayer-backed incentives do not exceed avoided utility costs, that load management participation is accessible across income groups, and consider protections for vulnerable customers when transitioning to a class-wide rate design. In addition to these considerations, estimating resiliency and equity costs and benefits and incorporating them into rate and program design would support more equitable outcomes.

[8] For each census tract in Massachusetts, population shares for the ten vulnerable groups are converted into component indices, each ranging from 0 to 100/10 (or 10) in value. A higher score indicates a greater degree of vulnerability. The SVI is the sum of these component indices and ranges from 4 to 64.

ES Figure 4. Massachusetts 2025 Social Vulnerability Index



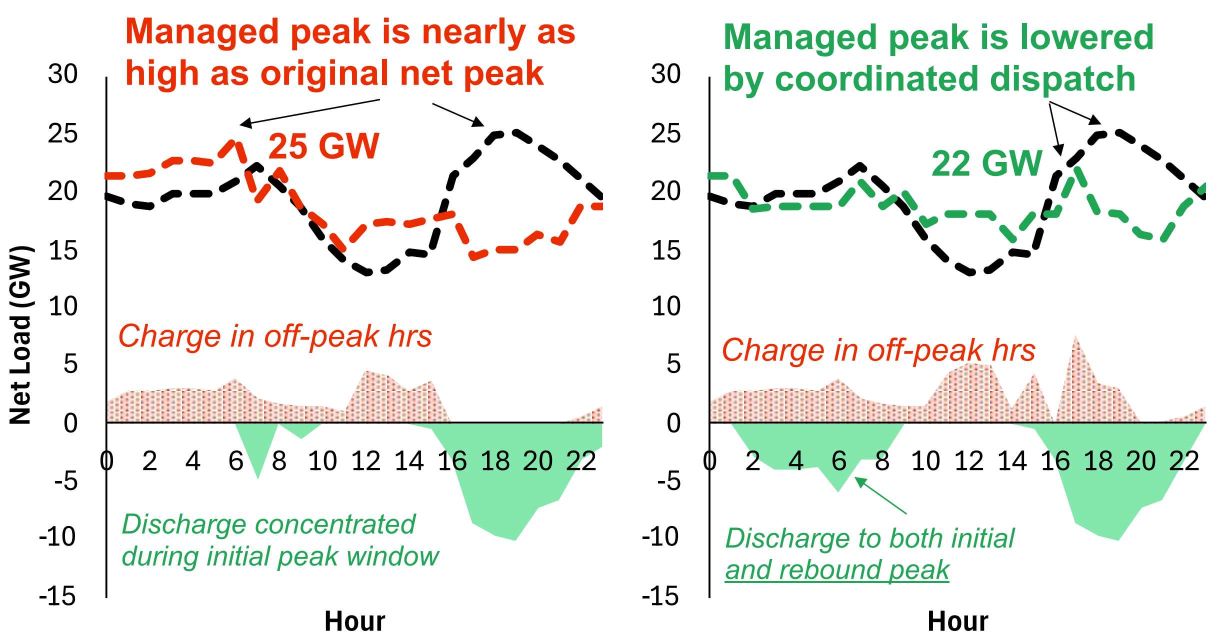
Notes: Non-residential census tracts are defined as those with fewer than 500 households. These tracts are not included in the SVI calculation.

Key Finding 4: Clear price signals that reflect real-time electric system costs, through market participation and/or rates and programs, can maximize benefits across the different components of the electric system.

Price signals that do not reflect real-time electric system costs run the risk of non-optimal customer dispatch. Misaligned price signals and dispatch can lead to inadequate compensation for bulk and local grid services provided or could even lead to a period of higher system costs if rebound peak demand from load shifting exceeds initial peak demand as shown in ES Figure 5. In the example shown for the peak day of 2050 from the CECP Growth Scenario, orchestration across load shifting measures could yield a ~3 GW reduction in net peak demand relative to uncoordinated dispatch of V2G and BTM storage. With initial utility load management programs already available to residential and commercial customers, increasing AMI deployment, and the expected transition to time-varying rates (TVR), price signals to shift and shed loads will need to be coordinated to ensure demand-side management is aligned with dynamic system benefits.

Virtual power plants (VPPs) and distributed energy resources management systems (DERMS) can help aggregate and orchestrate measure dispatch, i.e., coordinate the dispatch of different strategies to maximize benefits across bulk and local system avoidable costs. Orchestration and aggregation can create dispatchable and diverse load shift and shed portfolios across multiple customers, increasing resource reliability and enabling the integration of load management into utility planning. VPPs and DERMs can be encouraged by establishing clear market participation rules and ensuring cost-reflective price signals, which ISO-NE is aiming to do in the next three years, to comply with Federal Energy Regulatory Commission (FERC) Order 2222.[9] Ensuring that third-party and utility aggregation see gains from growing their portfolios also establishes a clear incentive for these operators to reduce barriers to load management participation for individual customers, thus helping accelerate uptake of demand side management.

ES Figure 5. Example of Uncoordinated Load Flexibility Creating Rebound Peak Demand (left) and Coordinated Demand (right), January 5, 2050



Key Finding 5: Scaling up load management in the Commonwealth will entail transforming electric retail rates, deploying participant- and utility-side hardware and software to enable flexibility, and increasing visibility into electric distribution system planning.

Scaling up load management in the Commonwealth to achieve the levels of peak reduction described in this study will entail overcoming several barriers to participation today. The accompanying DOER Recommendations Report[10] discusses these barriers and solutions. Key barriers identified in this study include the following:

- **Upfront costs.** High-performance measures such as ground-source heat pumps and deep building shell retrofits have significant upfront costs, limiting customer cost-effectiveness relative to lower-efficiency alternatives. High upfront costs are also a challenge for some

[9] Order from 2020, updated in 2021, directing regional grid operators to better enabled distributed energy resources to participate in electricity markets. ISO-NE implementation timeline available at https://www.iso-ne.com/static-assets/documents/100025/order2222_timeline.pdf.
[10] Available at https://www.mass.gov/doc/doer-peak-potential-report-and-policy-recommendations/download.

active measures, such as BTM storage, smart household devices, and thermal energy storage for commercial customers.
- **Technology-readiness**. Inadequate technology-readiness with metering infrastructure, device interoperability, and utility DERMS has also limited the deployment of active load management to date, although there are ongoing efforts to modernize and improve these technologies.
- **Market participation, rate design, and other compensation.** Transitioning to cost-reflective retail rates, enabling aggregated distributed energy resource (DER) participation in wholesale markets, and carefully considering the interactions of rates and programs will be essential to ensuring that customers see the right price signals to manage loads. This will entail utilities improving visibility into avoidable system costs across supply and delivery and ensuring that load management strategies are compensated for grid services provided.

Areas for Further Study

This study explored the cost-effectiveness and potential for load management in selected scenarios, aligned with CECP and more moderate electrification levels, in 2030, 2040, and 2050. While it provides useful insights into the potential for load management to support a more cost-effective energy transition, there are several areas where further research would help inform grid planning and policy priorities. These include:

Further Research Needs

To better understand how load management can fit into electric system planning, important areas of further research include:

- **Reliability of load management portfolios and performance of load management, especially under different weather conditions:** Integrating load management into long-term electric planning will require a deeper understanding of the reliability of load management strategies, especially during weather conditions that contribute to grid stress. Aggregation can help increase load management reliability by diversifying across different measures, but there are limited examples of this at scale to date. In Massachusetts, pre-heating measures and EV charging management would likely see reduced participation and reliability during extreme cold snaps, due to real-time space heating needs and reduced battery performance and slower charging in cold conditions. Thus, a critical next research step is evaluating the resource adequacy contribution of load management strategies, both individually and as portfolios, under extreme cold conditions.
- **Impacts of rates and program design on load management potential:** Further study is needed on how to design rates, programs, and wholesale market participation so that load management and other DERs receive appropriate price signals that reflect different electric system costs.
- **Evaluating geospatial bulk system and distribution system value:** Research should focus on identifying how periods of locational system value align with bulk system value at different levels of renewable build out and assumptions about supply side avoided costs. The MassCEC

Grid Services Study[11] explores some of these questions, including compensation structures for DERs that help avoid and defer distribution system investments. A key data need here is additional availability of substation or feeder-level system hosting capacity and constraints, to enable analysis of the benefits provided by DERs across time and locations.

- **System-level modeling of impacts at scale:** Robust capacity expansion modeling is needed to better capture the large-scale impacts of load management strategies. Such modeling would reflect how these strategies influence the entire portfolio build-out and potential avoided costs as load management adoption scales up.

[11] https://www.masscec.com/resources/grid-services-study

Introduction and Approach

The Massachusetts electric grid is expected to change dramatically over the coming decades, given the need to absorb building and transportation electrification demand while making investments to reduce reliance on fossil fuels, integrate renewable energy, and modernize and expand grid infrastructure. Widespread electrification will also change the shape and timing of electricity demand, including an expected shift to a winter peak by the mid-2030s.

Meeting these evolving grid needs will involve significant new investments in the electric grid. Electric utilities are currently rolling out advanced metering infrastructure (AMI) across the state, which will enable widespread load flexibility and create new opportunities for customers to participate in more price-responsive opportunities to shift and reduce demand. Reliably meeting this new demand will also require substantial investment in generation capacity, transmission infrastructure, and distribution infrastructure. Load management can help align electricity demand with available supply and reduce load during the most grid constrained and expensive hours.

Study Objectives

E3 prepared this assessment on behalf of the Massachusetts Department of Energy Resources (DOER). With their direction and input, this study focused on three primary aims:

- Evaluate a **technical potential scenario** for load management in the Commonwealth in 2030, 2040, and 2050, under a pathway consistent with Net Zero.
- Conduct an economic analysis to estimate the **costs and benefits** of using load management.
- Assess **feasible potential scenarios** for load management in the Commonwealth, informed by measure cost-effectiveness, technology maturity, and customer participation barriers, considering two potential pathways with differing levels of electrification and associated load management.

This study has two primary products: 1) this report, summarizing methods, key findings, and barriers to load management today, and 2) a detailed spreadsheet model that provided the underlying analysis, which was provided to DOER to further iterate and adapt as needed in the future.

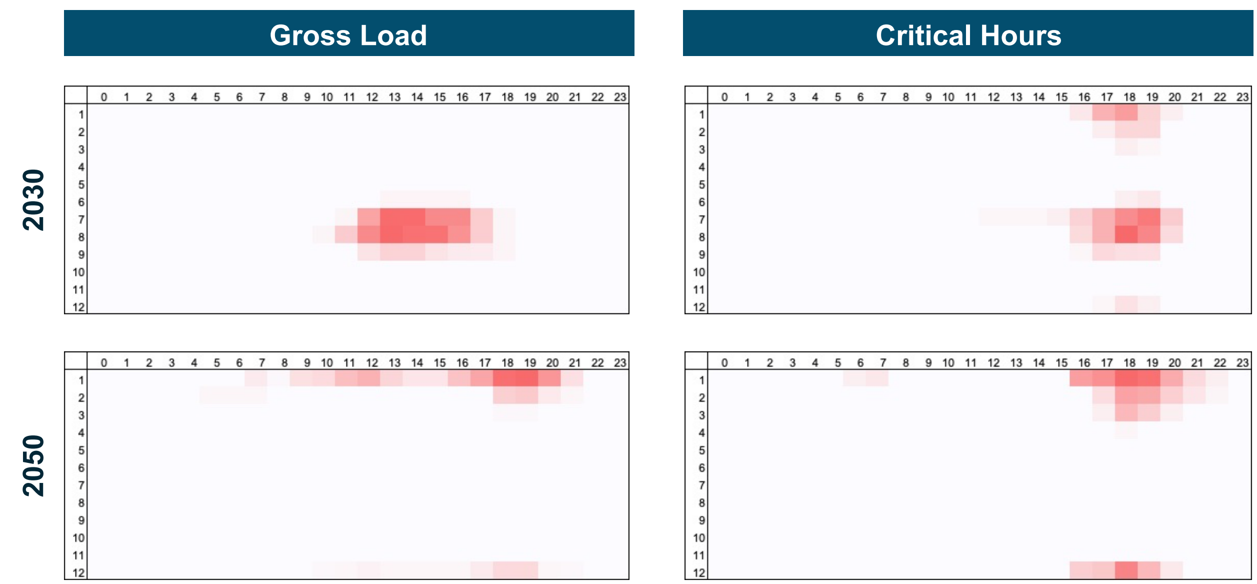
Load Management Modeling Approach

Critical Hours Framework

A key aim of load management is to reduce future generation capacity needs. Traditionally, both system planning and load management have focused on gross load, with capacity shortfalls most likely during the highest demand hours. However, as renewable energy is deployed, gross load is shifting the periods of greatest system stress out of the hours with significant renewable generation. To reflect this change, the load management potential analysis deploys active dispatch-limited load management strategies based on estimated critical hours, which identifies the specific periods when the system is most vulnerable to shortfalls. Critical hours closely align with net peak periods, i.e., periods with high demand net of all renewable generation, covering a broader set of hours compared to using the highest net peak hours alone. This is due to the critical hours framework also including periods during which small increases in demand or decreases in supply could result in unserved energy demand.[12]

A key implication of this approach is that the timing of greatest load management need evolves. As shown in Figure 6, the top 200 critical hours in 2030 that drive peak-driven generation capacity costs are in the summer evenings. In 2050, heating electrification drives a change in critical hours to winter evenings and mornings. This means that load management strategies will need to be able to dispatch to different periods of the year over time to provide the greatest system benefits. By contrast, the top 200 gross load hours extend earlier in the afternoon in summer 2030 and have a wider band of high load hours in winter 2050. Note that these 200 hours are expected to align more closely with transmission and local distribution system infrastructure needs. Peak-driven distribution system investment needs vary significantly across time and space due to heterogeneous customer profiles of those served, which is not captured in the state-wide aggregate gross load profiles shown here.

Figure 6. Top 200 Hourly Peak Capacity Allocation Factors among Critical (Net Load) Hours and Gross Load Hours for Massachusetts Electric System in 2030 and 2050



Notes: Darker red cells denote higher peak capacity allocation factors (PCAF). PCAF values reflect average month-hour contributions to total net and gross load across top 200 hours.

Strategies Modeled

This study considered load management strategies that can reduce or shift load during critical electric system hours, with a focus on bulk system avoided costs (generation capacity, transmission

[12] These hours were obtained from previous E3 modeling of the New England grid using a Loss of Load Probability (LOLP) model, which simulated the New England grid thousands of times based on historical weather conditions and expected future renewable output aligned with those conditions. See [Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets, August 2025](), for more information on critical hours.

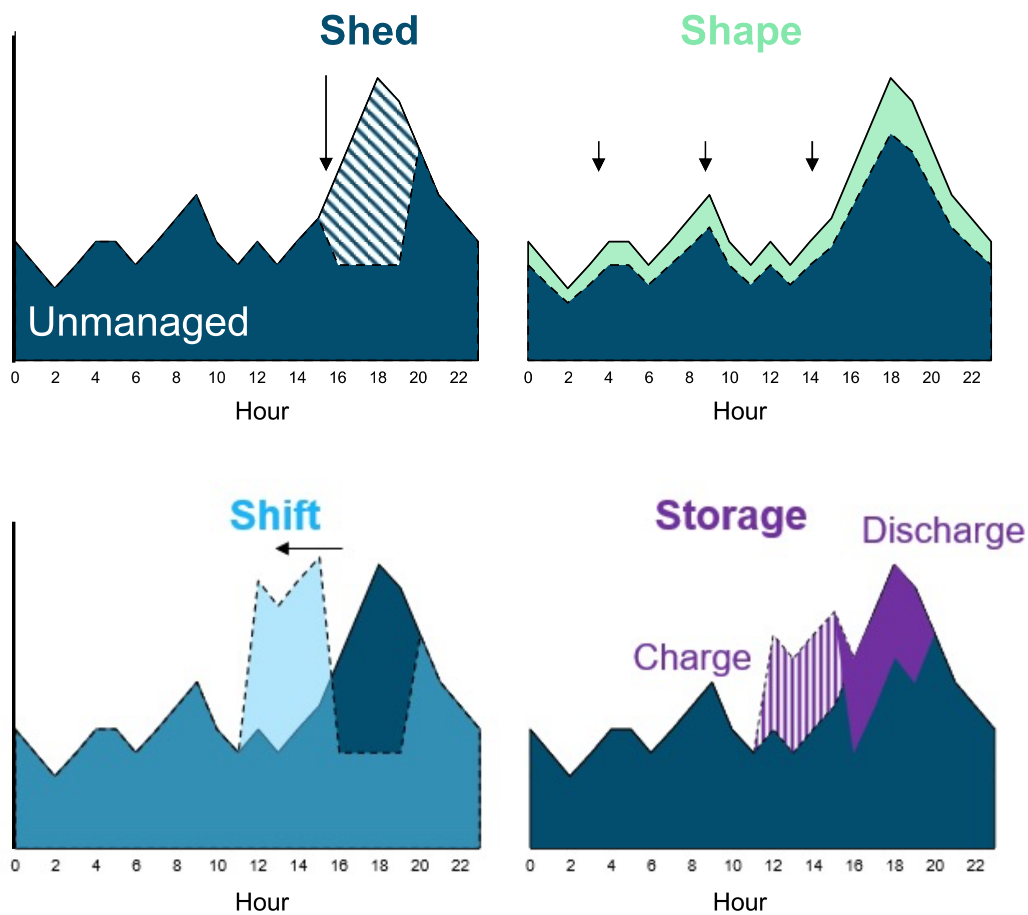
capacity, and energy).[13] For the assessment, load management strategies were organized into the following general categories, consistent with existing industry frameworks:

- **Shed:** Loads that can be curtailed during peak hours. These resources are typically those that can temporarily, on the scale of hours, reduce non-essential electric loads in response to signals from a grid operator. Examples of this include adjusting air conditioning set points to pausing non-critical commercial or industrial processes.
- **Shape:** Reshaped loads through energy efficiency. The efficiency resources modeled in this study provide sustained reductions across the course of the year compared to less efficient baselines. Examples of this include ground source heat pumps and building shell improvements, relative to lower-efficiency standard air source heat pumps. Behavioral change is also considered a "shape" load management measure but was not included in this study.
- **Shift:** Shifted loads, often referred to as load flexibility, reflecting resource loads that can be moved across hours, typically out of net peak hours, without significantly impacting end users. Examples of flexibility strategies include pre-heating and cooling or managed EV charging that moves charging to hours when electricity supply is high and/or other demand is low.
- **Storage:** Like other shifting strategies, storage helps to align supply with demand, shifting supply from hours with excess energy to discharge during challenging hours. This study considered the role of behind-the-meter (BTM) storage as a load management strategy.

An illustration of these different strategies is shown in Figure 7 below.

[13] A distribution-level assessment was beyond the scope of this assessment but is recommended and discussed in the study conclusion as an important area of further research. See https://www.masscec.com/resources/grid-services-study for more detail on locational distribution system benefit valuation.

Figure 7. Illustration of Load Management Strategies



This study evaluated a broad set of technologies for load management, reported in Table 1, with the specific capabilities and assumptions related to their potential described further below, as these vary by scenario. The list of technologies was informed by discussion with the Stakeholder Advisory Group, as well as prior studies such as the Lawrence Berkeley National Laboratory's 2024 California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050. The list below includes both active and passive strategies. Active strategies include measures that shift or shed loads during critical system hours, while passive strategies include efficient electric heating and building shell improvement measures that provide higher thermal performance throughout the year.

Table 1. Load Management Strategies Considered

Category	Load Strategy	Description
Shape	High-Efficiency and Hybrid Heat Pumps	High-efficiency heating measures can passively reduce heating and cooling load in many hours of the year. This includes ground source heat pumps (GSHPs) and cold-climate air source heat pumps (ccASHPs). These HVAC measures in this study are compared to a baseline with standard air source heat pumps, no shell retrofits, and base code for new construction.[14]
Shape	Retrofit Shell Upgrades	Deep shell retrofits and light shell retrofits reduce heating and cooling load through improved insulation in walls and attics, air sealing, and window improvements.
Shape	Stretch Codes	Specialized and stretch building codes for new construction and major renovation, already adopted by municipalities reflecting nearly 90% of the population of the Commonwealth, ensure reduced thermal load in new construction and major renovations across residential and commercial buildings relative to the base energy code.
Shape + Shed	Hybrid Heat Pumps	Hybrid heat pumps can reduce heating and cooling load by switching to existing non-electric heating systems during cold hours of low heat pump efficiency or high electric system need (i.e., critical system hours). This study includes a passive hybrid heat pump measure, which uses a temperature-dependent partial switchover to backup, as well as an active hybrid measure, with temperature-based switchover and 100% switchover to backup during the top 200 critical hours of the year.[15] Hybrid heat pump measures are not limited to a maximum number of consecutive shed hours.

[14] Most heat pumps installed in Massachusetts are cold-climate heat pumps. This study presents a comparison of cold-climate heat pumps to lower-efficiency standard air source heat pumps to underscore the risks of large electric peak demand growth from heating electrification using inadequately efficient heat pumps.

[15] Hybrid heat pump owners today primarily shift to non-electric backup heating systems based on outdoor air temperature, given reduced efficiency and sometimes higher heating costs of heat pumps at cold temperatures. The “active shed” measure modeled here would build on baseline temperature-driven customer switchover to additionally switch over to backup heating based on electric system needs, modeled here as the top 200 critical electric system hours.

Shed	Industrial Shed	Industrial shed is based on the current ConnectedSolutions Daily Dispatch industrial demand response framework. For this study, this measure is modeled as a generic, technology-agnostic demand response call for industrial customers. There are 90 3-hour calls assumed to occur in the top critical hours per year. For enrolled industrial buildings participating in the event, the demand curtailment realization rate is 80.5%. During each event, the participating load capacity is reduced by 80.5%.
Shift	EV Charging	Electric vehicle charging can be managed in V1G to reduce demand in high load hours. In V2G, electric vehicles can act as storage and dispatch to the grid in high load hours, reducing grid net load. Scenarios defined in this report use a mixture of unmanaged charging, managed V1G charging, and V2G charging.
Shift	Heating, Ventilation, and Air Conditioning (HVAC) Shift	Heat pumps, electric resistance heating, and air conditioning can be used in conjunction with smart thermostats to shift heating load to different hours of the day. Residential and commercial and industrial (C&I) buildings can be pre-heated and pre-cooled to reduce load in critical grid hours. These strategies are dispatched to respond to the top 200 critical hours of the year. The percentage of load reduction varies by technology and season and is described further in Table 3. HVAC shift is limited to consecutive critical hour streaks of 4 hours or less. The load that is reduced during the critical hour window is added uniformly to the window (of the same duration) prior to the critical hour event.
Shift	Water Heater Shift	Electric water heaters can shift water heating load to different hours of the day. Residential and C&I buildings can preheat water to reduce load in critical grid hours. These strategies are dispatched to respond to the top 200 critical hours of the year. Water heater shift is limited to consecutive critical hour streaks of 4 hours or less. The load that is reduced during the critical hour window is added uniformly to a window of the same duration prior to the critical hour event. The share of electric water heaters across electric resistance and heat pump technologies is determined by the CECP Phased scenario.

Shift	Appliance Shed + Shift	Appliance load can be either shed or shifted into other hours of the day, depending on the end use. Shifted appliance load includes dishwashers, washers, dryers, and pool pumps. Spas, plug loads, pool heaters, ovens, well pumps, and fans are assumed for shed loads. These loads are reduced or shifted by end-use specific demand response factors during the top 200 critical hours. Appliances are limited to shed or shift in response to consecutive critical hour streaks of 8 hours or less.
Storage	BTM Storage	BTM storage can charge and discharge flexibly to reduce strain on the grid. In this analysis, the available storage capacity can be dispatched in two different ways. 1. Storage dispatched <u>concurrently</u> with other load management strategies to reduce unmanaged net peak, prioritizing critical hour load reduction. Storage charges during lowest load hours and discharges during net peak hours. Concurrent management of all strategies creates the risk of a new modeled secondary peak. This approach is used in the benefit-cost analysis section of this study, to show the marginal cost-effectiveness of each unit of installed storage. 2. Storage dispatched <u>after</u> other load management strategies to reduce managed net peak. Storage charges in the new lowest load hours and discharges in the new highest load hours. Storage discharge may not occur in critical hours if other load management strategies have already reduced net peak in those hours. This approach is used to show the potential aggregate peak reduction achievable by each scenario's portfolio of strategies, allowing for greater peak flattening due to reduced rebound peaks.

Additional Key Considerations and Assumptions

Trade-offs between Load Management and Storage: As noted above, grid-scale or behind-the-meter storage plays a similar role in balancing supply and demand. Demand shifting strategies move demand to hours of lower cost or cleaner supply, while storage charges during times of excess renewable generation and discharges during the most expensive or grid constrained hours. Because storage and load management strategies often target the same net peak, these technologies are somewhat "substitutable" and may directly compete to flatten the same net peak demand. For the purposes of this study, the analysis assessed the ability of load management strategies and BTM storage to be deployed *before* grid-scale storage in building the technical and feasible potential scenarios. Projecting the likely mix of grid-scale storage and load management strategies to most cost effectively meet the state's future needs was outside the scope of this study. In reality, this will depend on a range of future conditions, including costs, market and program designs, interconnection barriers, and other enabling factors.

Saturation Effects and Measure Substitutability: When similar resources are added to a system with standard profiles, there is a well-researched “saturation” effect which occurs as load shifting measures flatten out peak demand during that time. If load management resources are added without coordination, or if they operate similarly in their ability to reduce load, the incremental benefit of each additional unit of peak demand flattening is decreased, as incremental resources are needed to provide dispatch for extended periods.

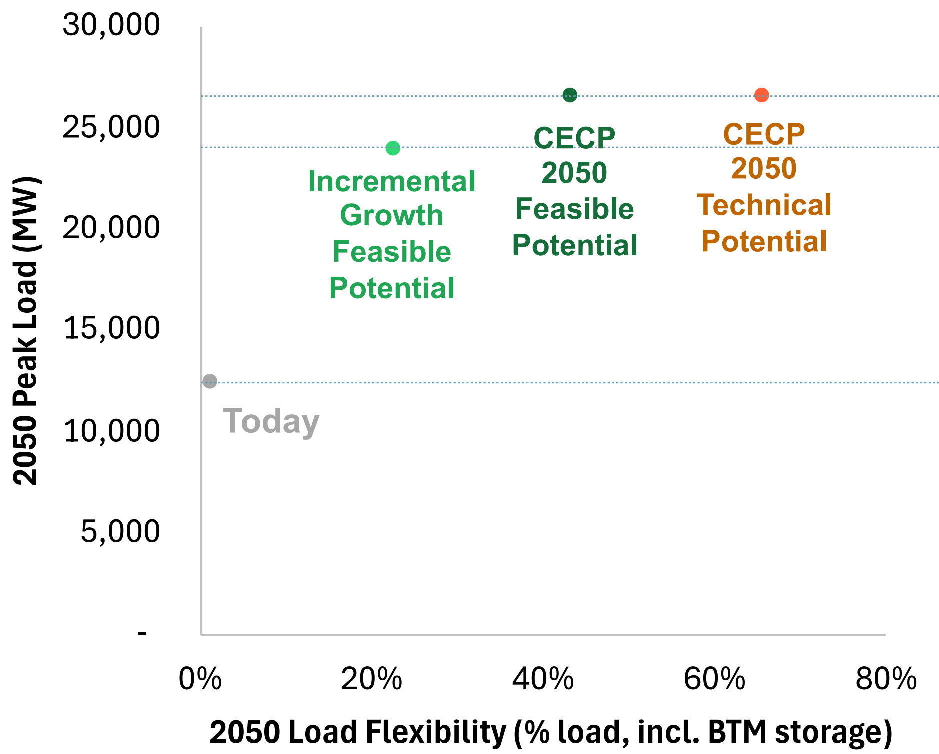
Mechanisms to Enable Load Management: There are several mechanisms, including different rate and program structures, that the Commonwealth could potentially use to enable or procure load management. These different mechanisms are not modeled explicitly, as this study focuses on evaluating the fundamental resource technology potential and the characteristics of different technologies to help manage load. While these different mechanisms are not modeled explicitly, E3 recommends future follow up work to explore enabling mechanism options, and test what will resonate with the communities, businesses, utilities, policymakers, and system planners.

Scenario Design

The E3 team, with input and guidance from DOER, designed three distinct scenarios to evaluate the potential for load management.

+ **Technical Potential under CECP 2050 Growth Scenario:** This scenario estimates the maximum amount of load management that could be achieved in a future consistent with the technology adoption portfolios in the Clean Energy and Climate Plan (CECP) 2050 Phased Scenario pathway. The CECP Phased Scenario gradually increases building heat pump adoption before accelerating electrification across buildings, transportation, and other sectors to achieve economy-wide decarbonization by 2050. This scenario provides a view of the total technical potential for load management assuming full uptake of projected electrification technologies and full participation in load management.
+ **Feasible Potential under the CECP 2050 Growth Scenario:** Building on the same technology adoption assumptions as above, this scenario applies more limited assumptions about how much load management may be realized. It reflects an optimistic case in which supportive policies, accessible incentives, and enabling technology investments accelerate the uptake of smart devices and flexible loads. In this future, aggregation and optimization through virtual power plants (VPPs) and distributed energy resource management systems (DERMS) enable widespread shifting and shedding of load.
+ **Feasible Potential under the Incremental Growth Scenario**: This scenario reflects a more conservative trajectory aligned with recent trends, with electrification adoption advancing incrementally in line with improving economics and progress toward state decarbonization goals but not necessarily reaching full CECP compliance. Assumptions about load flexibility are also more limited, reflecting steady but slower uptake of smart devices and more constrained aggregation and optimization of distributed resources.

Figure 8. Load Management Scenario Design



Notes: Load flexibility percentage value shown here reflects total load shifted or shed (including via BTM storage) in the top 200 critical system hours (roughly matching the top 200 net load hours), as a share of total net load in those hours, net of efficiency measures. Both CECP and Incremental Growth scenarios assume significant increase in EV and building loads by 2050. Peak load shown is for Massachusetts only, and is unmanaged, i.e., the peak loads shown do not include the impacts of load management measures.

It is important to note that the state's CECP load forecast already incorporates some load management measures. For this study, to avoid double-counting but evaluate where load management is needed, the study team began with a forecast that excludes load management. The study considered different heating electrification adoption trajectories, with the Incremental Growth scenario EV and heat pump adoption based on ISO New England's 2025 Capacity, Energy, Loads, and Transmission (CELT) forecasts, and CECP 2050 Growth scenario adoption aligned with the CECP 2050 Phased Scenario. In addition to these adoption forecasts, the study leverages technology-specific load shapes to assess load management potential relative to unmanaged loads using the same adoption baseline.

A summary of the load management scenario design is reflected below. The detailed measure-by-measure assumptions are then described in Table 2 and Table 3 below.

Table 2. Passive Load Management Measure Assumptions

Measure	Description	CECP Growth Scenario Adoption		Incremental Growth Scenario Adoption	
		2030	**2050**	**2030**	**2050**
Residential ccASHP	High-efficiency heat pump, high capacity retention at low temps (relative to standard HP)	4% of households[16]	57% of households	3% of households	44% of households
Residential GSHP	Very high efficiency individual ground source heat pump (relative to standard HP).	2% of households	13% of households	1% of households	5% of households
Hybrid Heat Pump[17]	Heat pumps which can reduce electricity consumption and switch to gas backup in cold temperatures.	21% of households	16% of households	12% of households	11% of households
Basic Shell (Retrofit)	Air sealing and attic insulation improvements, ~20% heating load reduction.[18]	30% of existing buildings	65% of existing buildings	30% of existing buildings	65% of existing buildings
Deep Shell (Retrofit)	Whole-home retrofit including foundation and	3% of existing buildings	13% of existing buildings	0% of existing buildings	0% of existing buildings

[16] The % values shown above refer to % adoption among all households in Massachusetts.
[17] Decreasing adoption numbers shown reflect CECP Phased Scenario decreasing reliance on hybrid heat pumps and increasing reliance on ccASHPs and GSHPs.
[18] Consistent level of building heating demand reduction observed from Mass Save programs supporting similar measures.

	wall insulation improvements, ~35% heating load reduction.				
Opt-In Stretch / Specialized Building Code	Reduction in thermal load over base code new construction - 60% reduction for residential, 24% reduction for commercial	90% of new construction	90% of new construction	70% of new construction	70% of new construction

Table 3. Active Load Management Measure Assumptions

Measure	Modeled Load Flexibility Assumptions		
	Technical Potential in CECP 2050 Scenario	Feasible Potential in CECP 2050 Scenario	Feasible Potential in Incremental Growth Scenario
Residential Hybrid HPs (Grid-Enabled)	Adoption and participation: 100% of households with hybrid heat pumps from CECP 2050 Phased scenario Lower efficiency heat pump, switchover to gas backup at low temps as well as during critical electric system hours	Adoption: 100% of hybrid heat pumps. Participation: 100% of hybrid heat pump electric load responds to load management event in 2030, 100% in 2050. *Realization rate of 100%.*[19]	Adoption: 100% of hybrid heat pumps. Participation: 100% of hybrid heat pump electric load responds to load management event in 2030, 100% in 2050. *Realization rate of 100%.*
Industrial Process Loads	Participation: 100% of industrial electric load enrolled in Daily Dispatch Connected Solutions program. Shed measure modeled for existing Connected Solutions curtailment realization (80.5%).	Participation: *202 MW in 2030, 477 MW in 2050.* *Realization rate of 80.5%.*	Participation: *162 MW in 2030, 382 MW in 2050* *Realization rate of 80.5%.*

[19] "Realization rate" here refers to the expected customer response among those enrolled to participate in demand response programs.

HVAC Flexibility	Adoption and participation: 100% of households with electric space heating from CECP 2050 Phased scenario, across modeled time-horizon. Load is shifted evenly into the preceding hours. Assuming 1-to-4-hour event, 100% to 65% load shifted for cooling; 20% to 13% load shifted for heating.[20]	Adoption: 60% of households with smart thermostats in 2030, 90% in 2050. Participation: 30% of smart thermostats in 2030, 40% in 2050. *Realization rate of 55%.*	Adoption: 60% of households with smart thermostats 2030, 90% in 2050. Participation: 60% of smart thermostats in 2030, 80% in 2050. *Realization rate of 55%.*
Water Heater Flexibility	Adoption and participation: 100% of households with electric water heaters from CECP 2050 Phased scenario, across modeled time-horizon. Load is shifted evenly into the preceding hours. Assuming 1-to-4-hour event, 100% to 40% load shifted.	Adoption: 100% of homes with heat pump water heaters. Participation: 50% of water heater electric load responds to load management event in 2030, 90% in 2050. *Realization rate of 100%.*	Adoption: 100% of homes with heat pump water heaters. Participation: 20% of water heater electric load responds to load management event in 2030, 60% in 2050. *Realization rate of 100%.*
Residential Appliance Shed + Shift	Adoption and participation: 100% of appliance load. Dishwasher, washer, dryer, pool pump: 100% of load is shifted evenly to the preceding 8 hrs. Spa, plug load, pool heater, oven, well pump, fans: Load is shed by 32.5% during top 200 critical hours.	Adoption not modeled. Participation: 20% of appliance load responds to load management event in 2030, 40% in 2050. *Realization rate of 100%.*	Adoption not modeled. Participation: 10% of appliance load responds to load management event in 2030, 30% in 2050. *Realization rate of 100%.*
Commercial Refrigeration	Adoption and participation: 100% of commercial square footage with refrigeration energy demand.	Adoption not modeled. Participation: 20% of appliance load responds to load management event in 2030, 40% in 2050.	Adoption not modeled. Participation: 10% of appliance load responds to load management event in 2030, 30% in 2050.

[20] Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources Through 2050, May 2024

	100% of load is shifted evenly to the preceding 4 hours.	*Realization rate of 100%.*	*Realization rate of 100%.*
V1G (Managed Charging)	Adoption and participation: 100% of EV charging load. V1G shifts all charging out of daily peak period to low-cost period contingent on vehicle location.	EV Adoption: 18% of light-duty vehicles in 2030, 91% in 2050. Participation: 25% of electric vehicle charging load responds to load management event in 2030, 45% in 2050 (V2G described below). *Realization rate of 100%.*	EV Adoption: 7% of light-duty vehicles in 2030, 66% in 2050. Participation: 15% of electric vehicle charging load responds to load management event in 2030, 75% in 2050. *Realization rate of 100%.*
V2G (Vehicle-to-Grid)	Adoption and participation: 100% of EV charging load. V2G discharges during peak period and charges in low-cost period contingent on vehicle location.	Participation: 0% of electric vehicle charging load responds to load management event in 2030, 50% in 2050 for LDV and 90% in 2050 for MHDV. *Realization rate of 100%.*	Participation: No V2G uptake. *Realization rate of 100%.*
BTM Energy Storage	Adoption: *278 MW in 2030, 3 GW in 2050.* BTM residential and commercial 3-hour battery systems deployed to minimize net peak.	Adoption: *278 MW in 2030, 3 GW in 2050.* *Participation and realization rate: 100%.*	Adoption: *167 MW in 2030, 462 MW in 2050.* *Participation and realization rate: 100%.*

Benefit-Cost Analysis Methodology

To inform the assessment, E3 evaluated the cost effectiveness of different load management measures from a total resource cost (TRC) perspective, which identifies the total change in net costs/benefits to the region. This test compares total benefits of a program or measure to the total costs, from the perspective of the state, excluding any utility incentives or transfers, and includes avoided utility costs, technology capital costs, and avoided emissions.

This analysis is done on a *marginal* basis – reflecting the incremental impacts of avoiding electric demand through load management in a given hour, based on the marginal generator in each hour of a given year. Marginal costs could change significantly over time depending upon the pace and scale of electrification, the changing mix of resources used to provide energy, notably increased renewable penetration, and demand side interventions to manage new load.[21] Load management *at scale* will change marginal resources and thus aggregate avoided costs of new incremental load

[21] Future avoided costs are an important source of uncertainty in this study.

management. Future work could complement this analysis by evaluating the total impact of load management on the aggregate costs of the grid.

The analysis leverages information related to the costs of load management measures from a range of sources, as described in Table 4 below.

Table 4. Costs and Benefits Evaluated

Cost/Benefit Component	TRC	RIM	Description & Source
Avoided utility marginal costs	Benefit	Benefit	Electric energy, energy demand reduction induced price effects (DRIPE), capacity, capacity DRIPE, transmission and distribution, reliability, gas energy (AESC 2024 CF5)
Technology costs - upfront and operations and maintenance (O&M)	Cost		Upfront and O&M costs for each measure from various sources (MassCEC 2025, LBNL DR Phase 4 Appendix C, NREL ATB 2024, literature review) details in appendix
Avoided emissions	Benefit		Social cost of carbon with 1.5% discount rate multiplied by marginal emission rates (AESC 2024 CF5)
Administrative costs	Cost	Cost	Residential and C&I administrative costs for implementing programs, including program planning, admin, marketing, advertising (3 Year Energy Efficiency Plans)

Per-Measure Marginal Avoided Costs

For the avoided utility marginal costs described above, annual avoided $/kW-year costs from the AESC[22] were distributed across the top 200 net load or gross load hours, using a peak capacity allocation factor (PCAF) approach to translate these avoided costs to a $/kWh basis.[23] Generation capacity and capacity DRIPE used were distributed via PCAF across the top 200 hours of net peak demand, while transmission and distribution system costs were distributed via PCAF across the top 200 gross load hours. Hourly electric energy costs and energy DRIPE were available from AESC for 2030, 2040, and 2050.

[22] Counterfactual case 5, the “All-In DERs” scenario, to reflect marginal costs in a future with high penetration of distributed energy resources.

[23] The PCAF method allocated weights to each hour, determined by the share of each hour’s load contributions to the total critical hour load (net or gross) across top 200 hours.

Aggregate Avoided Costs

To calculate the aggregate annual avoided costs for each scenario, this analysis multiplied the hourly avoided cost vectors for different electric system costs in each year by the aggregate hourly demand reductions in each scenario and summed the results across all hours of the year. The analysis for portfolio-level upfront capital costs translated $/sqft and $/device cost inputs to $/kW-yr inputs by dividing total stock capital costs by measure critical hour peak reduction from the technical potential scenario. For the annual portfolio TRC costs estimated for the feasible potential scenario, this analysis compared benefits (annual avoided electric system costs and emissions) to costs (administrative costs and annualized capital costs) across measures that were TRC net-beneficial for each year of the analysis.

Results and Discussion

This section summarizes and discusses the results of the load management analysis, including the technical potential, the benefits and costs, and the feasible potential.

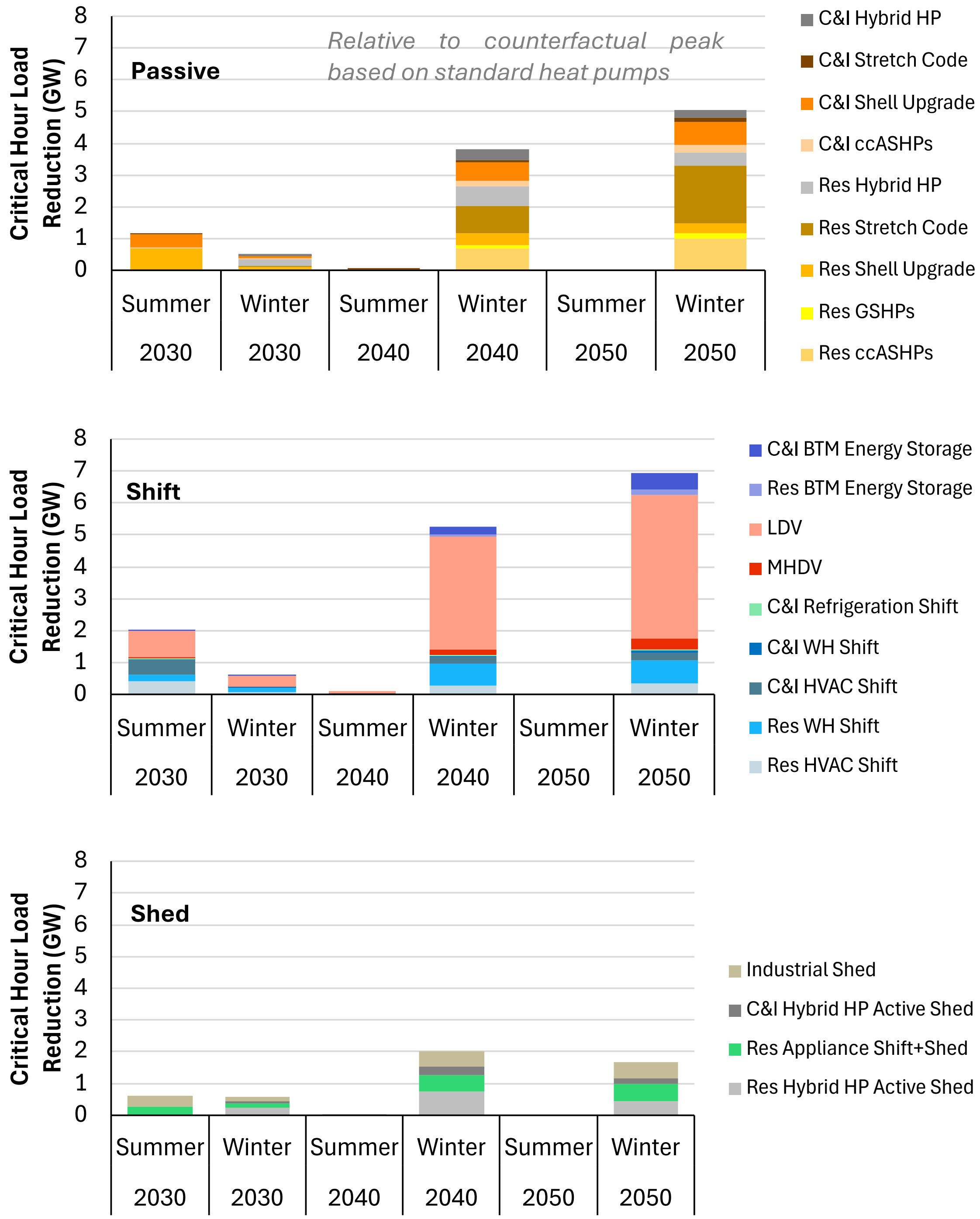
Technical Potential Results in the CECP 2050 Growth Scenario

To determine the technical potential of the measures included in this study, E3 assumed electric vehicle and heating load growth consistent with the CECP 2050 Phased scenario.

Figure 8 summarizes the total potential of each measure to reduce load (i.e., for passive and shed measures) or shift load from critical hours. The potential shown reflects a weighted average of peak load reduction across the top 200 critical hours and does not include increases in load outside of these hours. In the near term, the largest category of load management is from the deployment of managed vehicle charging, both in the near- and long-term. These estimates reflect the maximum share of load that can be reduced or shifted for each measure, as described in Table 2 and Table 3. The feasible potential estimates shown later reflect the range of technical potential that can be achieved, considering different participation rates across strategies.

Passive measures could play an important role in avoiding extreme peak demand increases from inefficient electric heating. Stretch codes for new construction are especially key for mitigating peak demand growth from the Commonwealth's expanding building stock, across residential and commercial buildings, relative to the base energy code for new construction. High-potential shift and shed measures include EV charging management, space and water heating load shifting, and hybrid heat pumps. The storage adoption trajectory shown here is determined by the adoption of BTM solar assumed in the CECP Phased Scenario, as well as by the total need for load reduction in critical hours and the loading order of measures assumed, as this study deploys non-storage measures first. With a cost-optimized dispatch approach and higher assumed installed capacity, the technical potential of BTM storage would appear significantly higher.

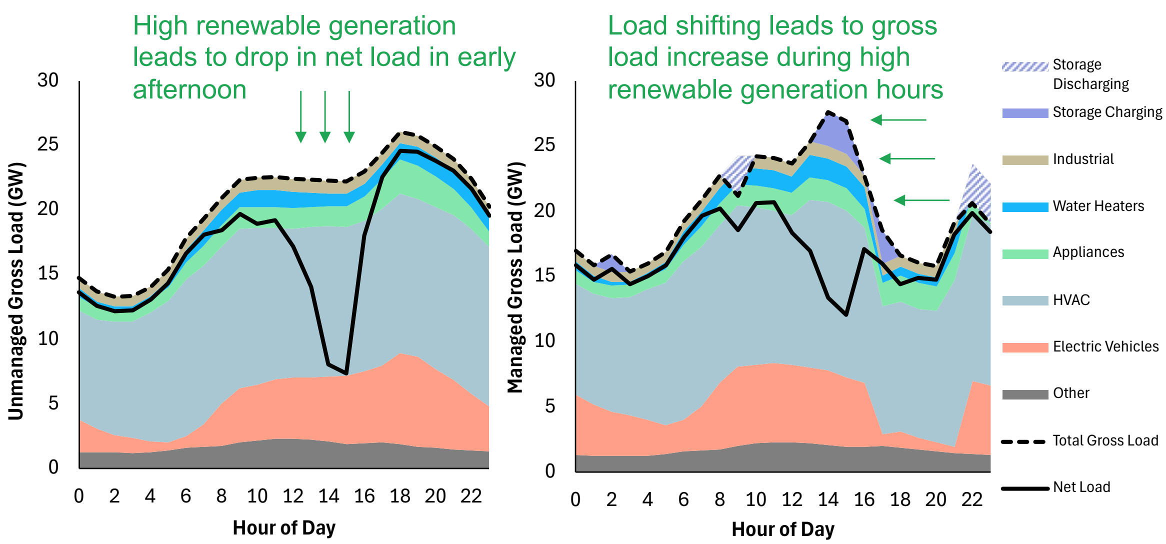
Figure 9. Aggregate Load Reduction in Critical Hours for Passive (top), Shift (middle), and Shed (bottom) Measures, Technical Potential Scenario



Notes: Weighted average of load reduction across top 200 of critical hours shown, where weights = contribution of each hour's load to total critical hour load across top 200 critical hours. Technical potential of deep shell retrofits and V2G measures are ~65% and ~275% higher than the light shell retrofit and V1G measures included above. BTM storage is deployed to original critical hours, but dispatch is limited by total cost-effective load reduction need post deployment of other measures; storage potential would be significantly higher if loading order was reversed.

While the figures above present the weighted average critical hour load reduction, Figure 10 shows gross loads across end uses from a peak day during winter 2050. This figure shows the large share of electric load from heating, ventilation, and air conditioning (HVAC) loads, reflecting space cooling demand in the summer and space heating demand in the winter. BTM storage dispatch offers the most flexibility with load shifting, although periods of sustained high net demand would present challenges due to the limited duration of battery energy storage. These conditions would create similar challenges for all short-duration shift measures. Similarly constrained over long spells of high net demand, space conditioning and water heating measures will otherwise be able to shift a sizeable amount of demand to earlier in the day via pre-cooling and pre-heating of homes. EV charging loads are highly flexible, although charging is constrained by where the vehicles are over the course of the day.[24]

Figure 10. Unmanaged (left) and Managed (right) Gross Loads on Peak Winter Day, 2050



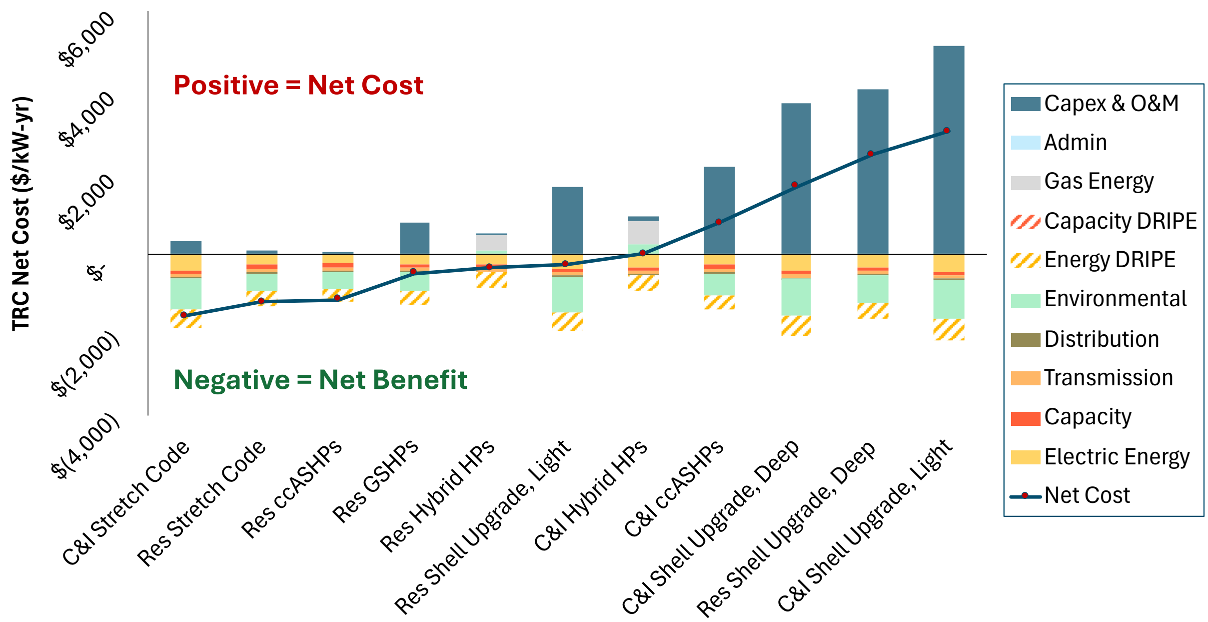
Benefit-Cost Analysis Results

The figures below show the TRC cost test results for the modeled measures. Figure 11 shows the levelized incremental lifetime net present value (NPV) TRC net costs per critical hour demand reduction. This cost metric is used across the benefit-cost analysis section to account for the lifetime avoided costs for an installed measure and to ensure that measures can be compared in an equivalent unit, i.e., net cost per unit critical hour load reduction, such that measures with greater critical hour reduction see lower net costs. This cost-effectiveness analysis seeks to present the comparative benefits and costs of measures to inform incentive design and policy strategy to bring down the costs of specific measures rather than screen out measures that appear expensive.

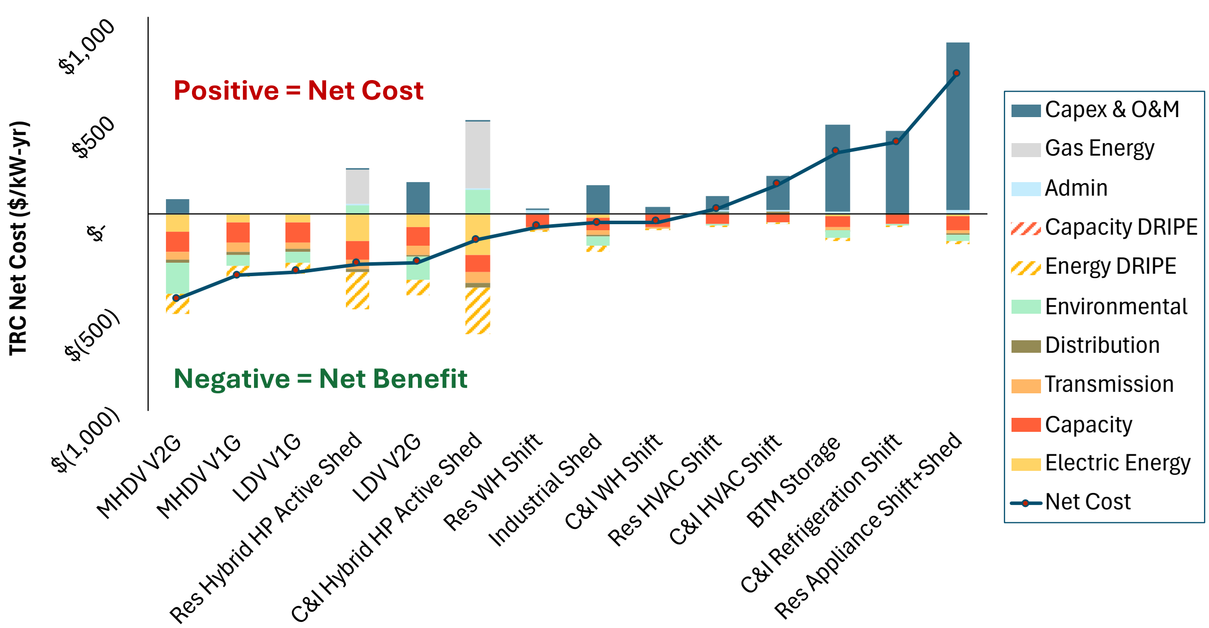
[24] See Technical Appendix for EV load shapes used in this study.

Figure 11. Levelized Lifetime Incremental Total Resource Cost Net Benefit, 2030

Passive Measures



Active Measures



Notes: Levelized lifetime NPV incremental total resource costs, including upfront costs, avoided electric system costs, administrative costs, environmental benefits per critical hour kW reduction. DRIPE = demand reduction induced price effect. Top 200 critical hours used to allocate generation capacity costs, while top 200 gross load hours used to assign transmission and distribution capacity costs. Hybrid heat pump measures include the cost of gas fuel but do not include the avoidable cost of gas infrastructure (avoidable gas infrastructure costs are highly uncertain but likely non-negligible).

Passive measure cost-effectiveness is dominated by annual energy and emission reduction benefits in addition to the peak reduction benefits that are the focal point of this study.[25] Of the passive measures, stretch codes for new construction and high-efficiency heat pumps such as ccASHPs and GSHPs are the most cost-effective compared to baseline building energy codes and standard lower-efficiency heat pumps respectively. These measures are already supported by existing programs in the Commonwealth and highlight the importance of continuing to pursue efficient electrification strategies. C&I electrification and building shell improvements emerge as more expensive and uncertain on an upfront cost basis. An advantage of these measures, also applicable for efficient electrification, is that they drive load reductions that are invisible to customers, i.e., no user intervention is required after installation, which helps reduce the load shift or shed needed from active measures.

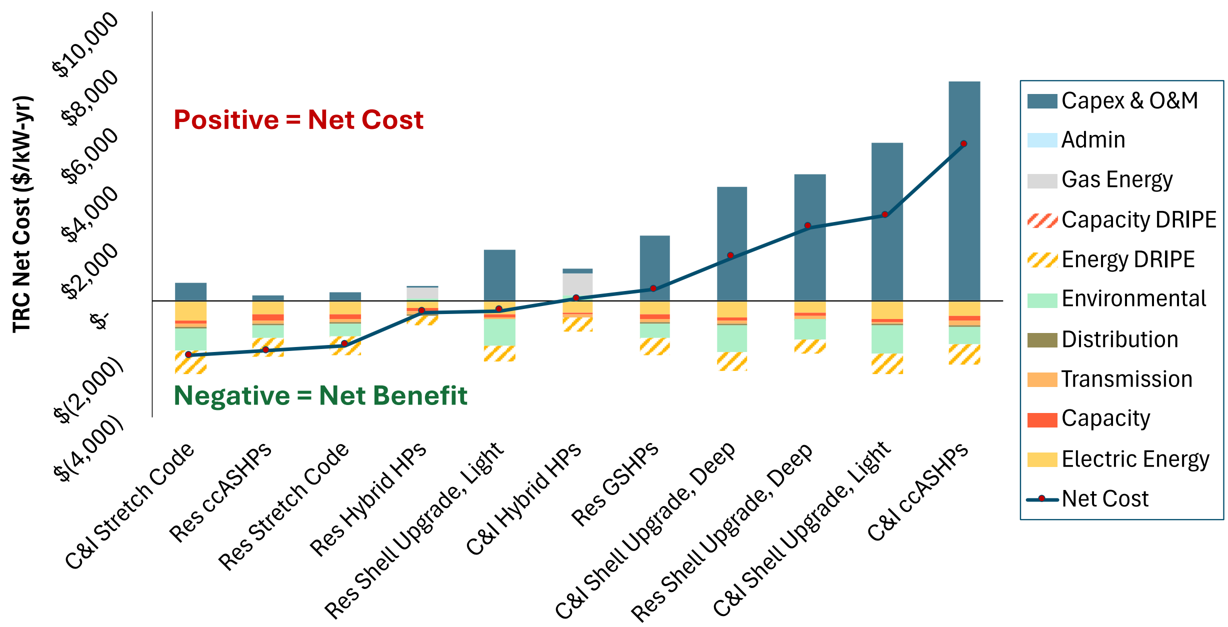
Active measures dispatch to critical hours with high generation capacity, transmission, and distribution costs, thus achieving a different composition of avoided costs than passive measures. Of the active measures, those with lower upfront cost barriers include V1G (which the model assumes has no incremental cost), grid-enabled hybrid heat pumps, water heating load shifting, and residential HVAC shifting. V2G also emerges as a net-benefit measure due to the magnitude of avoided electric system costs. Residential and C&I hybrid grid-enabled heat pump measures also face environmental impacts from gas use that offset their capacity, energy, and DRIPE benefits. The most expensive load shifting active measures are residential appliances and C&I refrigeration. The residential appliance costs shown here represent a conservative estimate; they include the incremental cost of a smart clothes washer and dryer, dishwasher, and refrigerator. These loads also could be shifted through customer behavior without needing grid-enabled devices. The conservative cost estimate reflects the greater resource potential that can be assumed with lower barriers to active management via device automation.

TRC costs change through 2040 and 2050, with a greater share of device years subject to a winter peaking system and changing capacity and energy costs. Critical hours in the winter translate to lower peak reduction benefits from space cooling compared to 2030 (relevant for high-efficiency heat pump measures) and greater lifetime benefits from grid-enabled hybrid heat pumps. This is because these measures avoid more critical hour load in winter-peaking years.

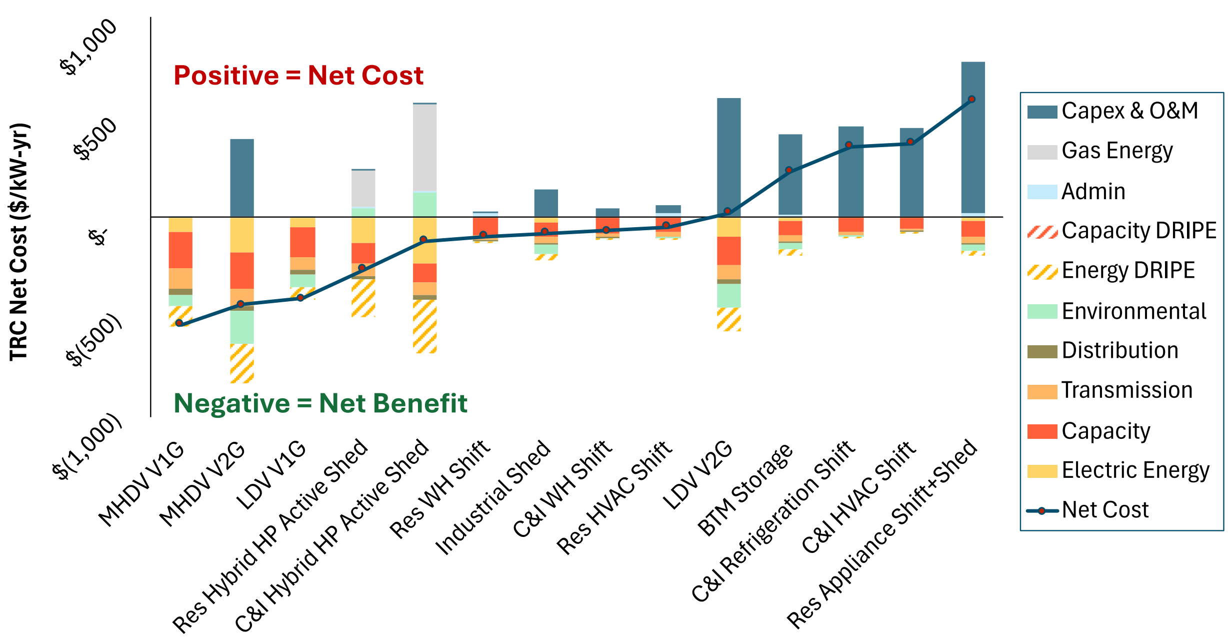
[25] Passive measure cost-effectiveness is typically shown on a $/kWh basis, as the primarily goal of energy efficiency is often energy savings. Normalizing the total avoided and incurred costs ($) by energy savings (kWh) rather than critical hour peak reduction (kW) would yield different relative cost-effectiveness across measures, decreasing the costs of passive measures relative to that of active measures. The overall “sign” of the measure yielding net benefits or net costs would remain the same across metrics.

Figure 12. Levelized Lifetime Incremental Total Resource Cost Net Benefit, 2050

Passive Measures



Active Measures



At an aggregate portfolio level, total feasible avoidable electric system costs through active measures in 2030 are on the order of $20M to $60M across scenarios. Savings rise in 2050 rise to $700M to $2B annually across Incremental and CECP 2050 Growth scenarios respectively. Passive measures would avoid an even larger amount of electric system costs due to their contributions to greater peak demand reduction. The annual avoided electric system costs modeled for passive measures range from $980M to $1.3B in 2030. In 2050, savings rise to $4.0B to $4.9B annually across scenarios. Focusing on only those measures with net TRC benefits, i.e., benefits greater than costs, we find avoidable electric system costs on the order of $650M to $950M in 2030, and $3.1B to $4.8B in 2050 across the Incremental Growth and CECP 2050 Growth scenarios respectively. After including capital costs and emission reduction benefits, net TRC benefits for these measures are $3.9B to $4.4B in 2030, and $7B to $9.1B in 2050. The methodology used to calculate aggregate costs can be found in the Aggregate Avoided Costs section of the methodology chapter.

Most of the passive measure avoided peak demand can be attributed to the efficiency gains of cold-climate heat pumps and stretch energy codes for new construction. These measures reflect existing policy and programs; the Commonwealth's existing ratepayer-funded energy efficiency program, Mass Save, already requires cold-climate certification and building weatherization for air source heat pump rebates. Roughly 90% of the population of the Commonwealth have already adopted stretch and specialized energy codes for new construction.[26] While cold-climate heat pumps are already the default heat pump assumed in existing electric system planning, the ESMPs did not model stretch codes. Thus, the additionality of peak reduction from passive measures shown in this study depends on the efficiency of technologies assumed in baseline load growth, which varies across different state and utility load forecasts.

This study does not analyze the non-participating ratepayer impacts of load management strategies. Further research can examine participant and non-participant costs under different rates and program designs to understand the balance of incentives needed to achieve favorable participant and ratepayer savings. Participant bill savings lead to reduced utility revenue collection from these customers, which would lead to increased costs for non-participants if program costs and reduced revenue collection exceed the avoided utility costs of service. These savings would change considerably with different rate and program designs. Appropriately reflecting the temporal variation and scale of utility marginal costs of service in rates would ensure that participants are appropriately incentivized and minimize cost shifts from participants to non-participating ratepayers, as explored in the Interagency Rates Working Group report on long-term rate design.[27] The risk of cost shifts to non-participating customers is high with incentive programs, especially those involving measures with high upfront costs or other adoption barriers faced disproportionately by disadvantaged communities. Careful, equity-centric program design can help avoid these issues by ensuring that disadvantaged communities participate in these programs and do not see cost shifts from misaligned utility costs and rate and program design.

[26] https://www.acecma.org/wp-content/uploads/energy-building-code-adoption-by-municipality-map-and-list.pdf

[27] Long-Term Ratemaking for a Decarbonizing Commonwealth, March 2025. Available at: https://www.mass.gov/doc/irwg-long-term-ratemaking-study/download

Feasible Potential Results

The feasible potential scenarios are informed both by existing and projected adoption rates of electrification and flexibility-enabling technologies, participation rates in load management programs, and realization rates from existing demand response programs. As described in the Scenario Design section, the Incremental Growth case features lower uptake of electrification consistent with the ISO-NE CELT 2025 report, and a lower level of adoption of active and passive measures. The CECP 2050 Growth case assumes a higher load growth, consistent with the CECP 2050 Phased scenario, and it assumes higher passive and active measure adoption.

While not explicitly modeled in this analysis, the higher share of active measure adoption explored in the CECP 2050 Growth case could be achieved through encouraging load management aggregators, such as third-party VPP operators, who, in turn, are then incentivized to increase customer participation. Ensuring that aggregators see benefits from scaling up load management can help bring innovative strategies to reducing customer barriers to participation.

Figure 13 presents load duration curves for each scenario in 2030 and 2050, showing the net peak reduction achieved by passive and active measures. The sorted net demand hours presented include the new peak hours that emerge from shift measures, especially in the CECP 2050 Growth case, where BTM storage and V2G capacity are high. These load duration curves can be used to estimate the absolute net peak reduction achieved by load management strategies.

Figure 13. Net Load Duration Curve in Critical Hours across Modeled Scenarios

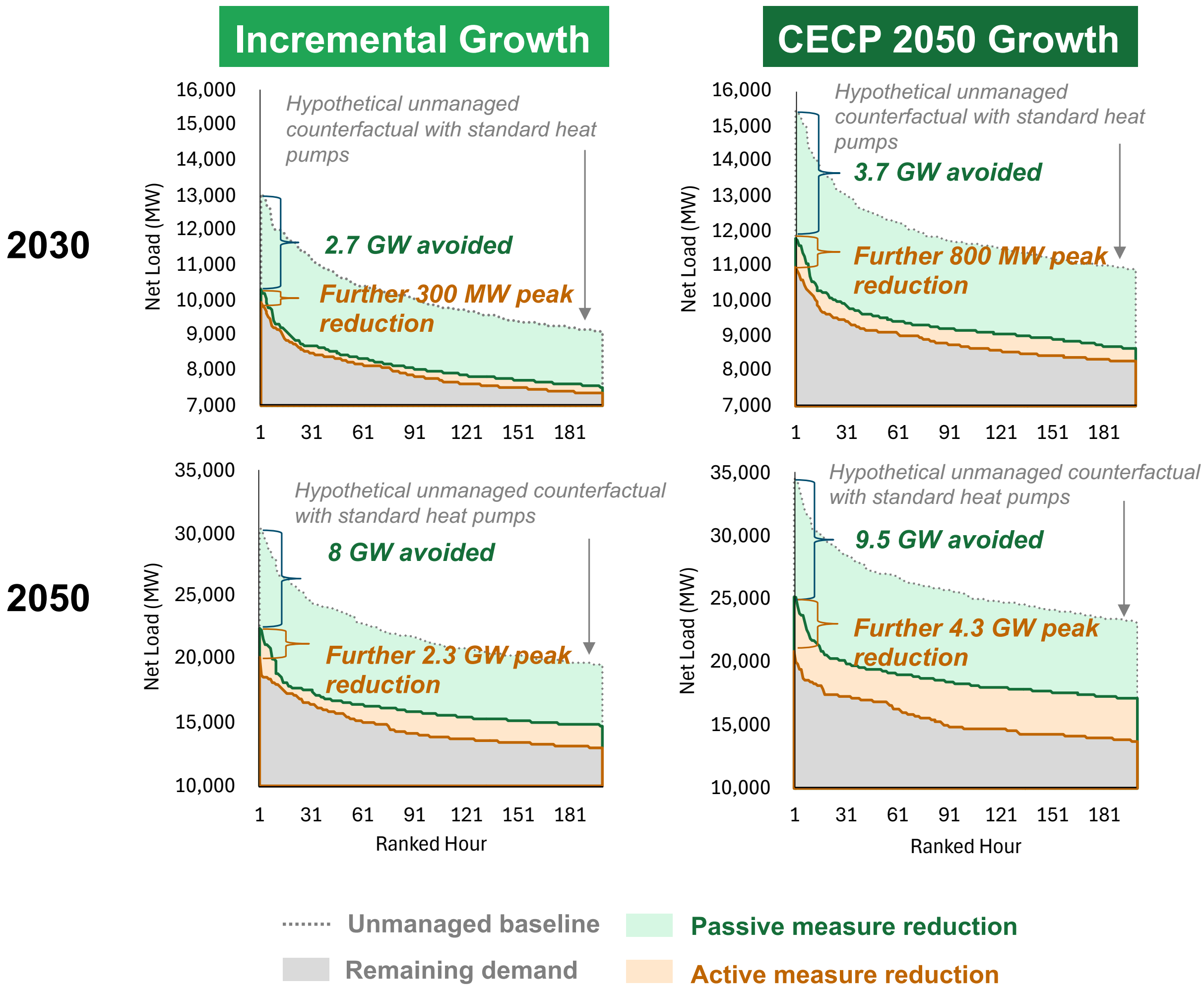


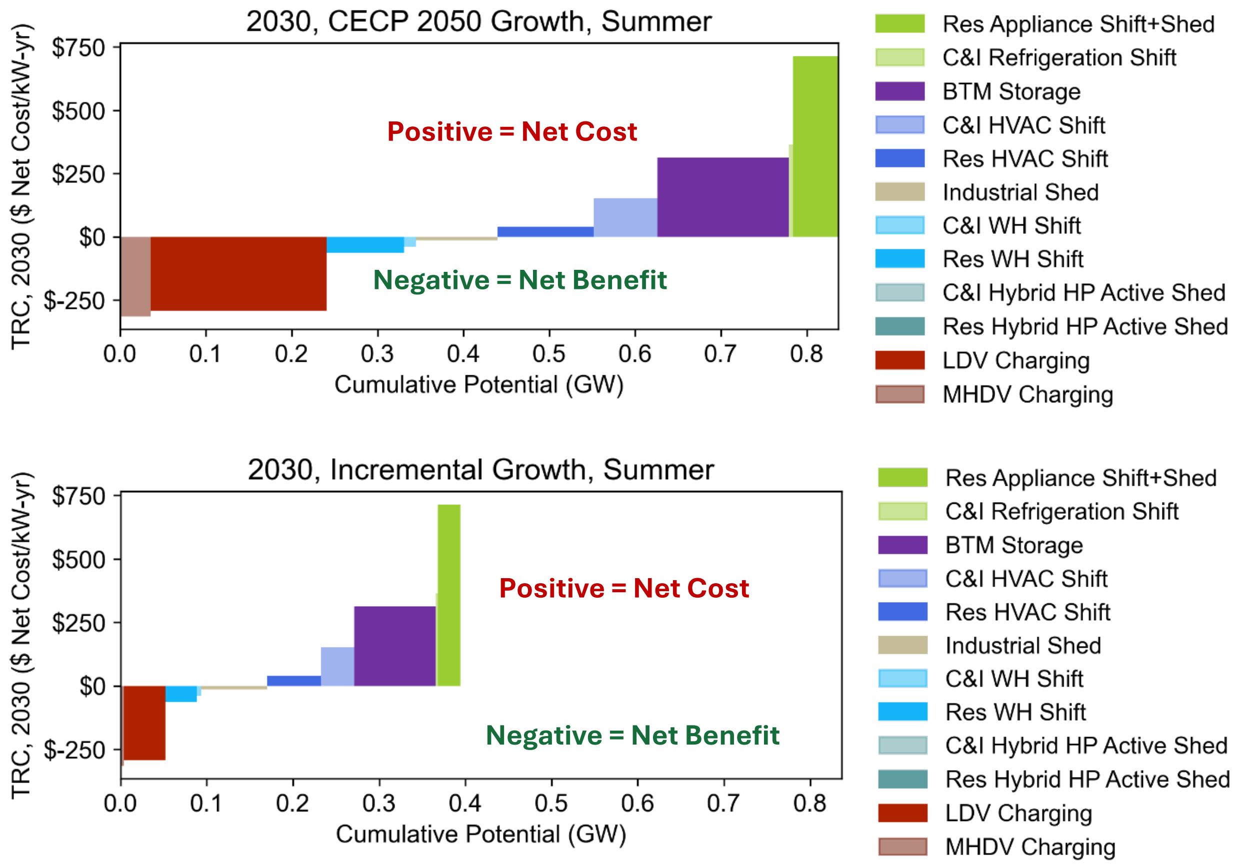
Figure 13 shows that passive load management avoids 2.7 to 3.7 GW of peak demand by 2030, and 8 to 9.5 GW by 2050. Active load management further flattens peak demand by 300 to 800 MW by 2030, and 2.3 to 4.3 GW by 2050. The coordination and aggregation of shift measures such as BTM storage and V2G helps achieve further flattening by dispatching to smooth net load over the course of the day. Without access to clear and consistent price signals that reflect real-time electric system costs, load shifting resources run the risk of creating rebound peaks that limit the avoidable cost potential of these measures.

In the Incremental Growth scenario, which leans on ISO-NE electrification trajectories and more limited flexibility assumptions, passive measures avoid 2.7 GW of peak demand by 2030, and 8 GW by 2050, relative to futures using standard air source heat pumps without any further building shell improvements. These peak load reductions translate to 21% and 26% of counterfactual peak demand net of renewable generation in 2030 and 2050 respectively. Active load management achieves 300 MW of net peak reduction by 2030, and 2.3 GW by 2050, translating to 3% to 10% of remaining net peak demand respectively. In this scenario, active and passive load management together can reduce gross peak demand by 20% in 2030 and 30% in 2050.

The CECP Growth scenario, aligned with electrification adoption from the CECP 2050 Phased Scenario and higher flexibility participation, shows passive measures avoid 3.7 GW of peak demand by 2030, and 9.5 GW by 2050, relative to futures utilizing standard air source heat pumps without additional building shell improvements. This translates to 24% to 27% of net peak reduction by 2030 and 2050 respectively. Active measures flatten peak demand by 800 MW by 2030 and 4.3 GW by 2050, translating to 7% to 17% of net peak respectively. In this scenario, active and passive load management together can reduce gross peak demand by 24% in 2030 and 30% in 2050. The V2G capacity modeled in this scenario could provide significant additional grid support and energy balancing; however, V2G is still in an early commercial phase and requires bidirectional chargers, vehicle compatibility, and utility interfaces, and its deployment is likely to depend heavily on coordinated utility, ISO-NE, and state policy support.

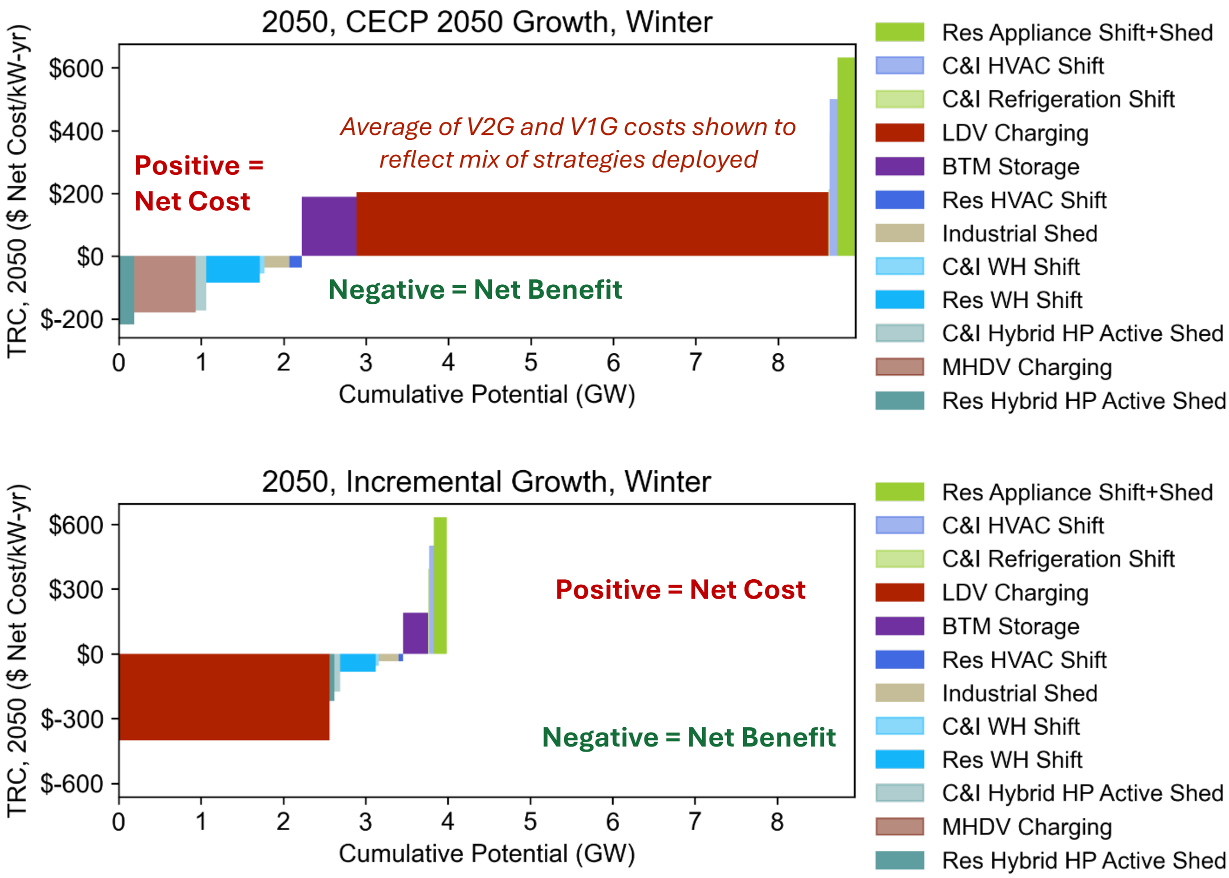
Figure 14 and Figure 15 illustrate active measure technical potential TRC net costs and load shifted out of critical hours under both feasible potential scenarios. These supply curves show only the load shifted out of peak hours; they do not include the effect of increased off-peak demand on the new net peak. Passive measures' supply curves are included in the appendix (Figure 23 and Figure 24).

Figure 14. Feasible Potential Scenario Net Costs and Load Reduction Potential, Summer 2030



In 2030, the 2050 CECP scenario achieves over 850 MW of critical hour load shifting or shedding, compared to 400 MW in the Incremental Growth scenario. EV charging has the strongest net TRC benefit and resource potential, presenting a clear opportunity in the near-term for policymakers and electric system planners to pursue. Water heating shifting presents net benefits and a small amount of resource potential, while industrial shed measures present larger resource potential at lower net benefits. HVAC load shifting is likely net cost given enabling smart thermostat costs but presents sizeable resource potential across residential and commercial cooling. BTM storage appears to be a net TRC cost strategy, given high capital costs of battery storage relative to the avoided bulk electric system costs.

Figure 15. Feasible Potential Scenario Net Costs and Load Reduction Potential, Winter 2050



By 2050, the CECP 2050 scenario exceeds 8.5 GW of load that can be shifted and shed out of critical hours. This achievement is primarily driven by an increase in load shifting potential by V2G, which has slightly lower net benefits than V1G but higher resource potential due to increasing cycling of EV batteries as storage resources. Active measure cost-effectiveness increases relative to 2030 due to higher avoided generation capacity costs, although avoided emissions and energy DRIPE reduce over time, both outcomes of the AESC 2024 costs used in this study. Water heating shift measures still score among the highest net benefits across measures and present a valuable opportunity to pursue across the modeled time horizon. Hybrid heat pumps that can actively shed load during critical hours become increasingly cost-effective as generation capacity, transmission, and distribution system costs are driven by winter heating peaks. However, this study did not include any avoidable gas distribution system costs that may be enabled by widespread all-electric heat pump adoption or reflect potential customer energy affordability challenges faced by gas customers in high customer departure futures – these issues are out of scope of this study and are actively explored in the D.P.U. Future of Gas 20-80 Docket.

Key Learnings from Feasible Potential and Benefit-Cost Analysis

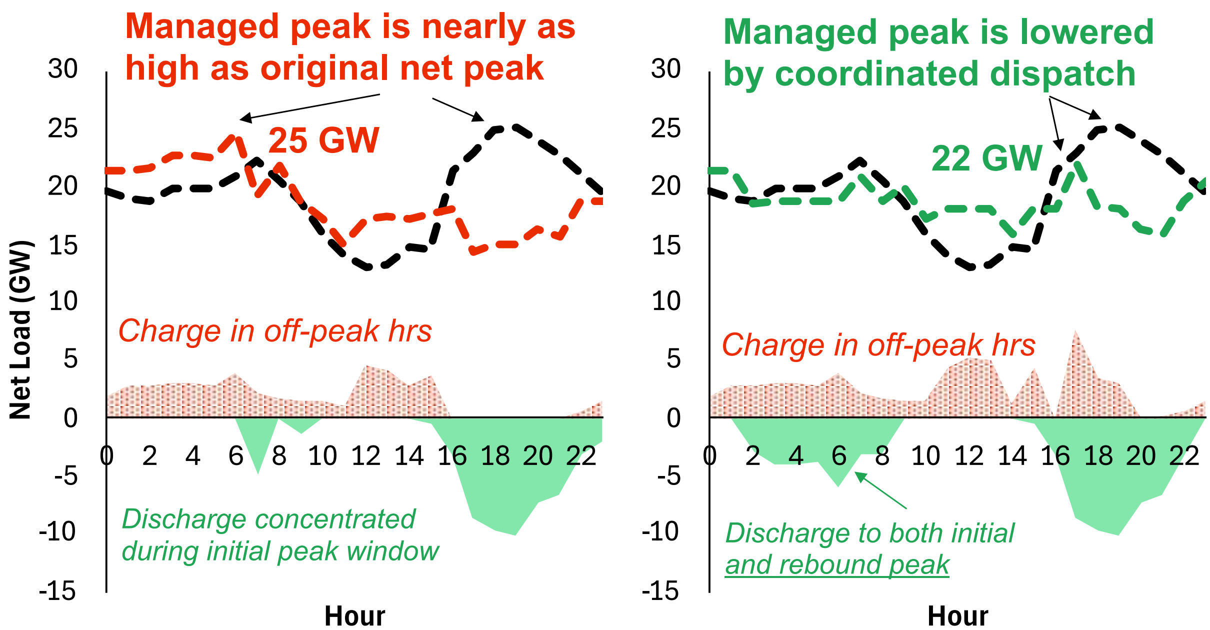
Examining a range of load growth and flexibility outcomes yields valuable insights into low-regrets strategies to pursue, regardless of broader clean technology adoption trends, as well as the enabling costs of pursuing high-potential strategies.

1. Managed EV charging is a low-cost, high-potential strategy across scenarios. The scenarios show that peak reduction achieved by V1G is a direct function of EV adoption; if the Commonwealth is to achieve the levels of electrification required to meet economy-wide climate goals, managing EV charging will be an important tool to mitigate peak demand growth.
    a. V2G entails higher enabling technology investment (such as installing bidirectional chargers), potentially at net TRC cost, relative to V1G's net TRC benefits. If V2G costs decrease as the technology matures and traverses the learning curve, load management potential would increase significantly (2.5-3x in the analysis shown).
2. Several energy efficiency measures such as stretch energy codes, hybrid heat pumps, and light building shell improvements remain a cost-effective approach to reduce peak demand.
    a. High-performance ground-source heat pumps, deep residential building shell improvements, and commercial building envelope improvements require significant technology investments that lead to net TRC costs. Decreasing the costs of these measures would yield expanded peak reduction potential.
3. Water heating flexibility can provide 500 to 700 MW of critical hour peak reduction by winter 2050. The Commonwealth can realize these gains by ensuring that all newly-installed heat pump water heaters are flexible by default.
4. Appliance load shifting and pre-heating could yield 300 to 500 MW of critical hour peak reduction by 2050. While the incremental technology costs of flexible devices can lead to net TRC costs, both behavioral changes that shift consumption out of peak hours and a move toward adoption of flexible devices by default would yield societal benefits.
5. BTM storage is a high-potential strategy with peak reduction dependent on the scale of adoption across homes and businesses. However, peak reduction benefits present a net TRC cost for the bulk grid, with higher enabling costs compared to EV charging management, building load flexibility, and front-of-the-meter storage. However, this analysis did not consider the resiliency benefits of BTM storage, or the range of potential distribution system benefits from avoiding local peak growth.

Need for Orchestration of Distributed Energy Resources

Figure 16 illustrates the importance of load management orchestration via clear, consistent price signals to customers that reflect time-varying electric system costs and ease-of-access to market participation, to maximize benefits to the grid. This figure demonstrates a peak winter day from 2050 in the CECP Growth scenario. In the chart on the left, active measures exclusively target periods of high net demand, which creates a new net peak that is nearly as high as the original peak. In the chart on the right, the management of resource charging and discharging of resources flattens net demand across the day through coordinated dispatch of V2G and BTM storage, thus avoiding 3 GW of net peak demand. This outcome highlights the benefits of load management aggregation and orchestration that can be accomplished through VPPs and DERMs.

Figure 16. Example of Load Management Orchestration, January 5, 2050



Resiliency and Equity Impacts of Load Management Resources[28]

Resiliency and equity impacts are often difficult to quantify and/or monetize for inclusion in conventional cost-effectiveness tests because they are not easily translated into dollars. For example, it is difficult to place a monetary value on benefits like "wellbeing" or "comfort," and some load management resources (like behind-the-meter battery storage) offer resiliency benefits on their own but may offer greater resiliency benefits when paired with other load management resources.[29] As a part of this study, AEC conducted an extensive literature review that identified eight resiliency and equity impacts that result from load management resource deployment (see Table 5 below) and synthesized key findings from the literature that value, quantify, and/or monetize the resiliency and equity benefits from load management. AEC's review found that the resiliency and equity benefits have significant value, even though monetized value estimates of these potential benefits are rare (see the Social Vulnerability Index Analysis section in the appendix for a summary table of quantified benefits available in the existing literature).

This study's cost-benefit analysis excludes the resiliency and equity impacts described here. However, it is important to note that this study is intended to estimate the total technical and feasible potential of load management resources across the entire Commonwealth (rather than assessing the costs and benefits associated with any specific load management program). Including resiliency and equity impacts is particularly difficult at the Commonwealth-wide level because these impacts vary significantly across the Commonwealth's communities. When utilities serving the

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[28] This section of the report was developed by E3 study partner and subcontractor, Applied Economics Clinic.

[29] Avseikova, K. N.d. "Making Room for Resilience: Reflections from the Grid Edge." Opinion Dynamics. Available at: https://opiniondynamics.com/making-room-for-resilience-reflections-from-the-grid-edge/.

Commonwealth propose adjustments to existing or new load management programs, it is important that resiliency and equity impacts be quantified and monetized as fully as possible and included in cost-benefit assessments.

Table 5. Resiliency and Equity Impacts of Load Management

Impact	Load management benefits	Link to MA vulnerable communities
Avoided power outages	Shift and shed of load to reduce demand peaks and flatten load curves	Loss of power is most harmful for some groups: elderly, disabled, low-income, those with serious health conditions, or those reliant on electronic medical devices. Low-income households and other vulnerable individuals are less likely to have backup power, transportation for evacuation, or funds for alternative housing
Enhanced building-level resilience	Management of load, energy access during outages, efficient outage recovery	
Avoided disruptions to critical facilities	Avoidance of energy interruptions to critical infrastructure and facilities for community safety (e.g. hospitals, public shelters, clinics, community centers)	
Lower energy use and bills	Reduction in household energy use (passively and/or actively) and energy bills	Low-income and BIPOC households, older adults, and rural residents are more likely to be energy-burdened and to fall behind on their energy bills
Environmental and public health benefits	Facilitation of renewable energy integration (displacing fossil fuel generation and reducing the need for peaker plants)	Fossil fuel-fired power plants are typically located near low-income and BIPOC areas, putting these areas at higher risk for negative health outcomes
Enhanced indoor health, comfort, and safety	Improvement of indoor air quality, comfort, and safety by reducing air pollution and maintaining more stable, comfortable indoor temperatures	Low-income households live in lower-quality housing and are more likely to keep their homes at unsafe temperatures to save money
Job creation	Creation of jobs along the entire value chain, which in turn generates easily monetized benefits such as labor income	Low-income and BIPOC communities are less likely to have access to well-paid employment opportunities
Increased property values	Increased property values due to the valuation of new or upgraded load management equipment	Higher property values boost homeowner wealth but also increase property taxes and rents, which can lead to gentrification and displacement

Note: Some of these impacts are more difficult to quantify and/or monetize than others. For example, lower energy bills are easier to quantify than enhanced indoor comfort. While quantifying these impacts was beyond the scope of the current analysis, there are Massachusetts-specific resources that quantify "non-energy impacts" from energy efficiency programs.

The resiliency and equity impacts identified in Table 5 have the potential to benefit or harm vulnerable communities in Massachusetts, depending on load management program design, implementation, and performance. For example, load management resources can lower energy use and energy bills and therefore have the potential to either reduce or exacerbate existing energy burden disparities. Energy burden refers to energy costs as a share of household income. Because resource costs are three times higher for low-income households in the Commonwealth than the national average, Massachusetts households are more likely to fall behind or default on their energy bills and face utility disconnections.[30] If higher-income households become the primary adopters of load management resources, those households receive energy- and cost-saving benefits do not reach the Commonwealth's most energy-burdened households. Load management resources improve household and community resiliency and equity when their benefits target and reach vulnerable and underserved communities. Knowing whether load management programs are improving or harming equity requires tracking and monitoring the distribution of costs and benefits across Commonwealth communities, including direct outreach to vulnerable communities and stakeholders.

It is also important to note that vulnerable households and communities face particularly steep barriers to adopting load management resources. For example, high up-front costs are an important barrier for low-income households while renters face barriers when they cannot make home energy system upgrades. These hurdles can prevent the benefits of load management resources from reaching those who need them most.[31] As part of our analysis, AEC developed a Social Vulnerability Index (SVI) that combines values from ten measures of socioeconomic and housing vulnerability (see the Social Vulnerability Index Analysis section in the appendix for more detail about the SVI analysis and for maps showing the ten SVI components). A higher SVI score indicates multiple, overlapping vulnerabilities. For example, communities with a high SVI score could have a high share of low-income households, BIPOC households, households with limited English language proficiency, renter households, and energy-burdened households. Figure 17 shows SVI scores across Massachusetts communities as well as the location of fossil fuel-powered power plants across the Commonwealth: as is true across the country, polluting power plants are more likely to be located near vulnerable communities. The SVI results help to identify communities that are

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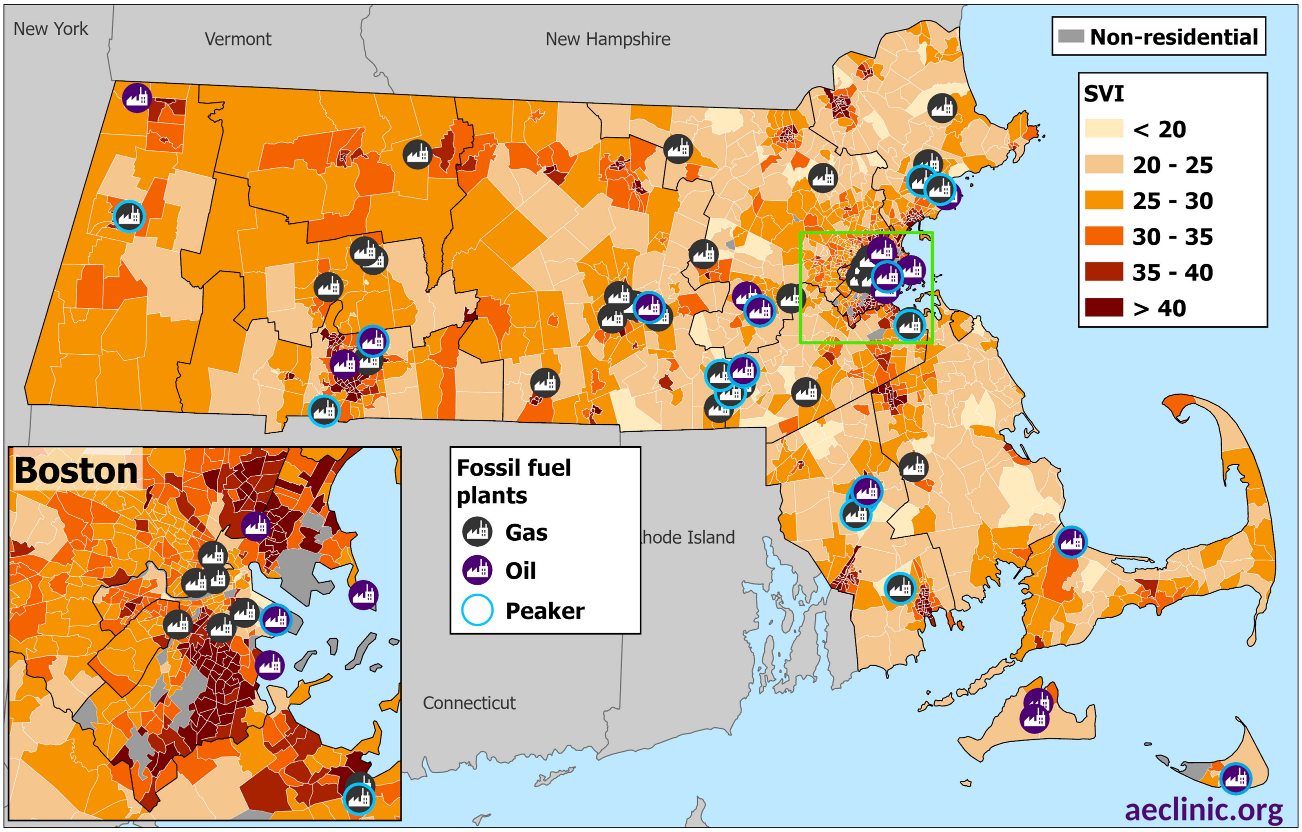
[30] (1) Woods, B., et al. 2022. Energy Storage Benefit-Cost Analysis: A Framework for State Energy Programs. Applied Economics Clinic. Available at: https://aeclinic.org/s/Energy-Storage-Benefit-Cost-Analysis.pdf; (2) American Council for an Energy-Efficient Economy (ACEEE). March 18, 2025. "Scorecard: Energy Efficiency Upgrades Help Struggling Families, but Most States Lagging." Available at: https://www.aceee.org/press-release/2025/03/scorecard-energy-efficiency-upgrades-help-struggling-families-most-states; (3) ACEEE. N.d. "Energy Burden Research." Available at: https://www.aceee.org/energy-burden.

[31] (1) Energy System Integration Group's Distributed Energy Resources Working Group. 2025. "Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets." Available at: https://www.esig.energy/wp-content/uploads/2025/02/ESIG-Demand-Response-Wholesale-Markets-report-2025.pdf; (2) Smart Energy Consumer Collaborative. 2021. "What's Stopping Renters from Engaging in Energy?" Available at: https://smartenergycc.org/whats-stopping-renters-from-engaging-in-energy/.

disproportionately burdened and should be targeted for benefits from load management resource deployment to achieve more equitable outcomes.

Figure 17. Massachusetts Social Vulnerability Index



Note: Non-residential census tracts are defined as those with fewer than 500 households. These tracts are not included in the SVI calculation.

Gaps to Realizing the Benefits of Load Management

While load management has the potential to reduce energy and capacity needs, and provide other benefits described above, technology, market, and policy gaps constrain the grid's ability to realize the benefits that load management can provide. This section summarizes key gaps and barriers as they exist today.

Technology Capability Gaps

Realizing the potential for load management will require a range of investments and advancements in enabling infrastructure across customer devices and energy management systems as well as utility information, communication, and coordination capabilities.

On the customer-side, advanced metering infrastructure (AMI), which provides utilities with interval data and two-way communication capabilities at the customer level, is being implemented in the Commonwealth. These capabilities are critical for providing utilities with the hourly load measurements required to establish dynamic price signals (e.g., critical peak pricing or real-time pricing) and demand response programs. Technologies must also have fundamental features that allow for the load management envisioned, such as controllability and interoperability, and home energy management systems will help ensure that customers easily understand and control their device loads. Load flexibility capabilities are often far less costly to enact at the time of manufacture or installation, making standardization and interoperability of hardware critical. For example, compatible bidirectional charging capabilities in purchased vehicles are a prerequisite for V2G.[32] External control for household appliances, such as dishwashers, to shift loads is less costly and in many cases only feasible at the time of manufacture. Even with modern smart appliances, the lack of interoperability standards creates cost and technical challenges to integrating technologies into coordinated programs. Interoperable standards for modular communications elements, such as CTA-2045, aim to close this gap.[33] However, even as standards and coordination increase, interoperability barriers exist across many other load management technologies such as behind-the-meter storage and V2G.

Utility- and third-party controls to facilitate aggregation of load management resources will be essential to lowering the barrier to participation in load management. In their Electric Sector Modernization Plans (ESMPs), electric utilities include future investments in DERMS, which allow for controllability and data collection at the appliance level. At the system level, to enable investments that support distribution level needs, ESMPs also identify the need for advanced distribution monitoring systems, which allow for automated controllability and monitoring of systems that have traditionally relied on non-visible, analog components. The Department of Public Utilities approved these utility investments with the expectation that these technologies become part of utilities' "normal planning practices"[34] to efficiently deploy load management strategies for addressing grid needs. Coordinating load management resource dispatch will be crucial to enabling effective market participation. Broadly, tools such as model predictive control (MPC) and VPP platforms can orchestrate large fleets of DERs but are still maturing.[35] Interoperability in coordination at the device and operator levels remains a challenge, despite open, device agnostic efforts such as OpenADR and IEEE2030.5 to develop standards for communication.[36] Aggregation via utilities or third-party operators presents unique opportunities and challenges. Utility-owned and operated aggregation could entail utilities and ratepayers taking on the risks of low load management realization during critical events, while third-party aggregators would likely take on these risks when providing aggregated load management services to utilities or regional system operators. Utilities are also likely best positioned to understand local distribution system needs and solutions through

[32] Houston, S., Reichmuth, D., and Specht, M. 2025. "Harnessing the Power of Electric Vehicles." Union of Concerned Scientists. Available at: https://doi.org/10.47923/2025.15888
[33] "OpenADR and CTA-2045." N.d. OpenADR Alliance. Available at: https://www.openadr.org/assets/OADR_CTA2045_Overview%20Webinar.pdf
[34] ESMP Phase II Order, D.P.U. 24-10-A/D.P.U. 24-11-A/D.P.U. 24-12-A at 161. Available at: https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aedeibdcj?ScNUM2JbDRIyMtx/w6Ugp62sCSWgooFb4RbJ6xIxlh+PcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6ngIfa80wd3rxFD8G4j981M2Rna9aVTXA
[35] Gerke, B. et al. 2024. "The California Demand Response Potential Study, Phase 4." Lawrence Berkeley National Laboratory. Available at: https://eta-publications.lbl.gov/sites/default/files/phase_4_dr_potential_study_final_2024-05-21.pdf
[36] "OpenADR and CTA-2045."

orchestration, although efforts to improve transparency and compensation of grid services would enable third party aggregators to better understand the benefits of their dispatch.

Policy Gaps and Enablers

Technology nascency, data access, inadequate incentives, and interconnection challenges are some of the biggest obstacles to scaling load management in the Commonwealth today.

In Massachusetts today, active demand response measures are still nascent. An evaluation of residential and commercial demand reduction initiatives such as the Connected Solutions program in the summer of 2023 found 56.5 MW of load reduction potential from residential batteries, 56.4 MW of targeted dispatch curtailment, 15.9 MW of daily dispatch curtailment, and <5 MW of commercial and industrial battery storage output.[37] Increasing participation in programs such as Connected Solutions will necessitate overcoming high enabling technology costs, metering infrastructure limitations, a lack of education and information about existing potential programs, and inadequate incentives to participate. Although overall enrollment is still growing, event-driven, aggregated demand response in critical periods of grid constraints has demonstrated performance in summer, high-stress periods in the Commonwealth.[38] Continued VPP performance as load management grows will be critical to iterating and improving our understanding of aggregated load management reliability for long-term electric system planning. This will be especially true as load management is adopted at scale, transitioning away from potential biases associated with early adopters.

Data availability is a challenge, with opaque data making it challenging for consumers to understand the potential costs and benefits of participation and for aggregators to advance load management programs. Flexible interconnection and automated control depend on secure, open communication about both planning and operational needs for the electricity grid. Indeed, the U.S. Department of Energy identifies transparent data as the first key solution for advancing efficient interconnection.[39] In Massachusetts, recently published hosting capacity maps, distribution level hosting capacities and other information enable aggregators to target enrollment. However, these data are not standardized across utilities and remain challenging to aggregate.[40] Following a 2021 regulatory order, New York recently released an initial version of a centralized platform to share both hosting capacity and customer energy data to support DER and other clean energy program growth.[41] New Hampshire and Maine have taken similar initial steps.[42] Such centralized, standardized, and

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[37] Demand Reduction Offering Evaluation studies conducted for Energy Efficiency Advisory Council in 2023-2024: https://ma-eeac.org/wp-content/uploads/MA23DR01-E-CI-CT_R2214-2023-Summer-CI-ADR-Evaluation-FINAL.pdf and https://ma-eeac.org/wp-content/uploads/MA-Residential-Energy-Storage-Demand-Reduction-Evaluation-Report_wInfographic-2024-03-20.pdf

[38] "Active Demand Reduction: Summer 2024 Recap." October 2024. MA EEAC. Available at: https://ma-eeac.org/wp-content/uploads/2024-ADR-Oct-EEAC-Mtg-10.18.24.pdf

[39] "Distributed Energy Resource Interconnection Roadmap."

[40] "US Atlas of Electric Distribution System Hosting Capacity Maps." N.d. Available at: https://www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps

[41] "First Development Phase Of The New York State Integrated Energy Data Resource Platform Completed" 2024. Available at: https://www.nyserda.ny.gov/About/Newsroom/2024-Announcements/2024_03_28-NYSERDA-Announces-Completion-of-First-Development-Phase-of-the-NYS-IEDR-Platform

[42] See NH-PUC Docket DE 19-197, Tab 199; ME Resolves 2022, Chapter 179, §1. A proposal submitted by utilities to DOE in 2024 envisioned a regional energy data system including MA; the current status is unclear. See https://www.puc.nh.gov/VirtualFileRoom/ShowDocument.aspx?DocumentId=3096cbae-8e69-4075-a19b-bdd306507916

interoperable data sharing provides an example of addressing this technical constraint to achieve load management potential.

Designing processes for flexible DERs to efficiently interconnect and participate in markets is critical to maximizing the value of these resources. Connecting load management solutions, such as BTM storage or V2G, often requires detailed interconnection studies. Standardizing requirements and timelines for simpler interconnection studies has the potential to improve outcomes.[43] Flexible interconnection, currently gaining prominence in large load rate design, is also used in the United Kingdom for DERs, allowing for curtailment in exchange for connecting prior to grid upgrades.[44] The Interconnection Implementation Review Group is actively working towards interconnection reform in the Commonwealth.[45]

Inadequate price signals for customers limit load management adoption. Most Massachusetts households have flat retail rates, which do not reflect the temporal and locational value of load flexibility. Rates and programmatic incentives must align with spatially- and temporally-accurate electric system benefits to ensure fair compensation for benefits provided across electric system avoided cost components. These compensation frameworks must evolve with changing grid needs as bulk and distribution system needs change with increasing renewable generation and economy-wide electrification. Since granular time-varying rates such as dynamic pricing may be confusing to consumers, these rate structures could be introduced by first exposing highly-flexible loads such as EV charging to real-time electric system supply costs.[46]

As explored in the MassCEC Grid Services Study,[47] the challenges and opportunities of developing cost-reflective price signals are particularly significant at the distribution level, where costs of electric infrastructure vary the most and are fast growing. Load management programs can provide valuable grid services that either defer distribution infrastructure investments or act as a 'bridge to wires' that allows for interconnection or load growth before conventional infrastructure upgrades can occur. Realizing grid services from load management efforts requires locational signals related to distribution-level needs that are not reflected in bulk market incentives. They might leverage existing DERs in new or different ways, as opposed to traditional non-wires alternatives (NWAs), which are often large scale, competitively procured, and newly built. Stacking incentives for different load management offerings may help match load management opportunities of different durations and frequencies to the needs of particular substations or other infrastructure.

Incentives for grid services at the distribution level should not compete with other rates and programs. Competition would create the risk of inconsistent price signals and non-optimal resource dispatch. Avoiding those requires coordination between different incentive programs and the value streams available in a particular location; compensation for distribution services should be less than or equal to the value of avoided distribution capacity. Price signals via time-varying rates and

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[43] Baldwin, D. et al. 2025. “Distributed Energy Resource Interconnection Roadmap.” U.S. Department of Energy. Available at: https://www.energy.gov/sites/default/files/2025-01/i2X%20DER%20Interconnection%20Roadmap.pdf

[44] CHARGED Initiative. 2025. “GREAT BRITAIN STUDY TRIP REPORT-OUT MEMO.” Available at: https://chargedinitiative.org/wp-content/uploads/2025/08/CHARGED-GB-Study-Trip-Report-Out.pdf

[45] https://www.mass.gov/info-details/utility-interconnection-in-massachusetts#interconnection-implementation-review-group

[46] “Long-Term Ratemaking for a Decarbonizing Commonwealth”, prepared for Interagency Rates Working Group in March 2025. Available at: https://www.mass.gov/doc/irwg-long-term-ratemaking-study/download

[47] https://www.masscec.com/resources/grid-services-study

programs such as ConnectedSolutions may complement distribution system needs by encouraging charging/discharging or load reduction during high system-wide net load periods. However, when local peaks differ from systemwide peaks, incentives may conflict. Moving beyond systemwide averages to locational information will require the integration of both customer capabilities and real-time, granular system needs, to enable maximum electric system benefits from coordinated load management dispatch.

Conclusions

This study estimates the technical potential, cost-effectiveness, and feasible potential of different load management strategies in the Commonwealth. The key findings of the study are summarized below.

Key Finding 1: Strategies to manage load may collectively deliver significant electric demand reductions in the Commonwealth. Passive load management measures such as cold-climate heat pumps and building shell improvements can avoid 2.7 to 3.7 GW by 2030 and 8 to 9.5 GW by 2050. Active load management such as EV charging management, building load flexibility, and BTM storage can further flatten peak demand by 300 to 800 MW by 2030 and 2.3 to 4.3 GW by 2050.

Passive measures, already supported through programs such as Mass Save, help limit both total energy need and peak demand growth associated with the building electrification needed to meet the Commonwealth's climate mandates. Residential stretch codes, cold-climate heat pumps, and building shell retrofits all lower thermal load in homes and businesses. These measures reduce energy demand throughout the year and require no customer action after installation. Active measures can target critical periods of need for the electric system, shifting and shedding load out of high-cost hours. EV charging management, building space and water heating load shifting, and BTM storage are especially high-potential measures in the near- and long-term.

Key Finding 2: Passive and active load management strategies are expected to deliver net benefits, with EV charging management, cold-climate heat pumps, and stretch codes for new construction providing the greatest net benefits of measures analyzed. Total avoided electric system costs from cost-effective measures reach $3.1-$4.8B in 2050 prior to considering program costs, with $7-$9.1B in total resource cost net benefits across Incremental and CECP 2050 Growth scenarios respectively.

By reducing load in critical hours, load management strategies can avoid future generation capacity, transmission, and distribution system costs. Passive measures are also able to reduce energy and emissions costs year-round. Most load management measures examined are net-beneficial from a total resource cost perspective, highlighting the opportunity for electric system cost savings through price signals to encourage load management. Price signals in rates and programs that must reflect system costs and benefits to ensure that participants and non-participating ratepayers alike see cost savings from load management.

Key Finding 3: Load management, when paired with careful program design, has the potential to have positive equity and resiliency impacts for disadvantaged communities if programs are designed with this specific intention in mind.

Communities across Massachusetts face a wide range of resiliency and equity impacts from load management, which can exacerbate or improve existing differences in social vulnerability. Incorporating these impacts into utility and state program design can help ensure equitable access to the benefits of load management. These benefits including increased building resiliency, reduced energy burden, and improved environmental health. Addressing barriers to adoption of load management measures for disadvantaged communities and minimizing inequitable cost shifts will be important steps to ensuring positive equity impacts of load management programs.

Key Finding 4: Clear price signals that reflect real-time electric system costs, through market participation and/or rates and programs, can maximize benefits across the different components of the electric system.

Clear price signals that reflect bulk and local electric system needs are essential to ensure optimal load management strategy dispatch. VPPs and DERMs can enable aggregation and orchestration of load management measures across a diverse set of customer end uses and coordinate resource dispatch to maximize electric system avoided costs. Aggregation can increase portfolio reliability and better enable the integration of load management into electric system planning. These aggregators can be supported through easy access to market participation.

Key Finding 5: Scaling up load management in the Commonwealth will entail transforming electric retail rates, deploying participant- and utility-side hardware and software to enable flexibility, and increasing visibility into electric distribution system planning.

Key barriers to load management today include inadequate technology-readiness with metering infrastructure and device interoperability, limited market participation opportunities for aggregated demand response, and inadequate compensation for grid services provided. Progress on these fronts will require investments in enabling technology to reduce costs and increase capabilities, increased visibility into time- and location-specific electric system costs, and transformations to rate design and market access.

Resiliency and Equity Impacts of Load Management Appendix

As mentioned in the Resiliency and Equity Impacts of Load Management Resources section above, AEC's review of the existing literature found that the resiliency and equity benefits from load management resources may have significant value, even though monetized value estimates of these potential benefits are rare (see Table 6 for a summary table of quantified benefits available in the existing literature).

Table 6. Key quantification/valuation findings for resiliency/equity impacts of load management resources

Impact	Key quantification/valuation findings	Citation
Avoided power outages	"Value of lost load" (VoLL) is $61/kWh in New England, ranging from $2.86/kWh for residential customers to $103.42/kWh for commercial customers	AESC Study Group. 2024. *Avoided Energy Supply Costs in New England*.
	In the northeastern United States, residents are willing to pay $1.70 to $2.30/kWh to avoid power outages	LBNL. 2023. *Shedding Light on the Economic Costs of Long-Duration Power Outages*.
	For the average U.S. residential customer, WTP survey shows that VoLL is $1.00 to $4.20/kWh	Woo, C. K., et al. 2021. "Average Residential Outage Cost Estimates for the Lower 48 States in the U.S." *Energy Economics, 98*.
Enhanced building-level resilience	In greater Chicago, doubling the number of customers with resilient and backup power systems could moderate outage-induced GDP losses by 14 percent	Wing, I. S. et al. 2025. "A Method to estimate the economy-wide consequences of widespread, long duration electric power interruptions." *Nature Communications, 16, 335*.
	For every $1 invested in building-level natural hazard mitigation (i.e. improving building shells), $4 is saved	National Institute of Building Sciences. 2018. *Mitigation Saves: Mitigation Saves up to $13 per $1 Invested*.
Avoided disruptions to critical facilities	Maintaining power in community shelters prevents serious health risks (e.g., CO poisoning, heat stress, and hyperthermia)	EPA. 2025. "Power Outages and Indoor Air Quality (IAQ)."
	Unplanned outages in healthcare facilities cost $7,900 per minute due to reduced productivity, equipment damage, data loss and patient care disruptions	Ponemon Institute. 2013. *2013 Cost of Data Center Outages*.

Lower energy use and bills	Load management resources could address 20 percent of estimated U.S. peak load in 2030, amounting to $15 billion annually in avoided system costs	Brattle Group. 2019. *The National Potential for Load Flexibility: Value and Market Potential Through 2030.*
	Demand-side management programs could help meet about 10 percent of U.S. peak demand in 2030	ICF. 2025. *Rising current: America's growing electricity demand*.
	Behind-the-meter storage can save commercial customers $2 to $15/kW on their annual utility bills	LBNL. 2019. *Implications of Rate Design for the Customer-Economics of Behind-the-Meter Storage*.
	An average residential customer who weatherizes an electrified home can save $150 to $1,200 per year on energy bills, with most households seeing savings of $500 to $800 annually	ACEEE. 2023. *Empowering Electrification Through Building Envelope Improvements*.
Environmental and public health benefits	Load management can reduce carbon emissions from U.S. homes by 27-55 percent	Bovornkeeratiroj, P., et al. 2023. "Quantifying the Decarbonization Potential of Flexible Loads in Residential Buildings." *Association for Computing Machinery*.
	Boston's 2050 carbon neutral goal could avoid 213 premature deaths in Suffolk County alone and save $2.4 billion from better air quality across eastern Massachusetts	NOAA. 2020. "Boston's Ambitious Climate Plan Could Save Hundreds of Lives and Billions of Dollars Each Year."
	A 5 percent decline in electric generation across all hours in Massachusetts would result in annual public health benefits totaling $5.5 to $12.5 million	Michael's Energy. 2023. "Quantifying Non-Energy Impacts."
Enhanced indoor health, comfort, and safety	Investing in building envelopes can cost-effectively reduce mortality during extreme temperatures	U.S. DOE & PNNL. 2023. *Enhancing Resilience in Buildings Through Energy Efficiency*.
	Improving air quality in office buildings could generate $17-26 billion in annual health benefits by boosting productivity, reducing absenteeism and lowering health expenses	Fisk, W. J., et al. 2011. "Benefits and Costs of Improved IEQ in Offices." *Indoor Air, 21(3),* 357–367.
Job creation	Installing solar panels, batteries, and heat pumps could create more than 2 million jobs or nearly 141 million job-years (where 1 job-year is defined as one job for one year)	Sovacool, B.K., et al. 2023. "Building a Green Future: Examining the Job Creation Potential of Electricity, Heating, and Storage in Low-Carbon Buildings." *Electricity,* 36(5), 107-274.

	Installing 1,766 MW of energy storage could generate 6,322 job-years and $591 million labor income between 2016 and 2025	DOER. 2023. *Charging Forward: Energy Storage in a Net Zero Commonwealth.*
Increased property values	Energy efficiency building features increased the selling price of houses by 6 percent in San Antonio between 2008 and 2013	UTSA. 2015. *An Empirical Assessment of the Value of Green in Residential Real Estate.*
	In New England in 2024, several building shell improvements generated more than 100 percent returns (the projects add more to resale value than they cost)	The Journal of Light Construction. 2024. "2024 Cost vs Value Report."
	In Washington, D.C., homes with green features were sold for 2 to 5 percent more than those without such features	D.C. DOEE. 2015. *What is Green Worth? Unveiling High-Performance Home Premiums in Washington, D.C.*

Social Vulnerability Index Analysis

Social inequities, environmental injustice, and energy burden cumulatively impact individuals and the neighborhoods they live in, compounding negative outcomes for already overburdened communities. For example, BIPOC and low-income communities are disproportionately exposed to pollution, environmental hazards, and negative climate impacts[48] that put these same communities at higher risk of mortality and adverse health outcomes, including respiratory and cardiovascular diseases and heat-related illness.[49]

The AEC developed a Social Vulnerability Index to measure communities' relative vulnerability to negative impacts from the energy system (including the potential impacts of grid expansion, decarbonization, or load management) compared to other Massachusetts communities. The SVI combines values from ten measures of vulnerability, including measures of socioeconomic vulnerability and housing vulnerability (see Table 7).[50]

Figure 18 below shows how the SVI varies across Massachusetts communities while Figure 19 shows the ten vulnerability measures that comprise the SVI). Census tracts with the highest SVI scores are in cities like Boston, Brockton, Fall River, New Bedford, Pittsfield, Taunton, Springfield, and

[48] (1) Liu, J., Clark, L. P., Bechle, et al. 2021. "Disparities in Air Pollution Exposure in the United States by Race/Ethnicity and Income, 1990–2010." *Environmental Health Perspectives, 129(12).* Available at: https://doi.org/10.1289/EHP8584; (2) U.S. Environmental Protection Agency. 2021. *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts*. EPA 430-R-21-003. Available at: https://www.epa.gov/cira/social-vulnerability-report

[49] (1) Khadke, S., Kumar, A., Al-Kindi, S., et al. March 2024. "Association of Environmental Injustice and Cardiovascular Diseases and Risk Factors in the United States." *Journal of the American Heart Association, 13(7)*. Available at: https://doi.org/10.1161/JAHA.123.033428; (2) Beard, S., Freeman, K., Velasco, M.L. et al. 2024. "Racism as a public health issue in environmental health disparities and environmental justice: working toward solutions." *Environmental Health, 23(8).* Available at: https://doi.org/10.1186/s12940-024-01052-8

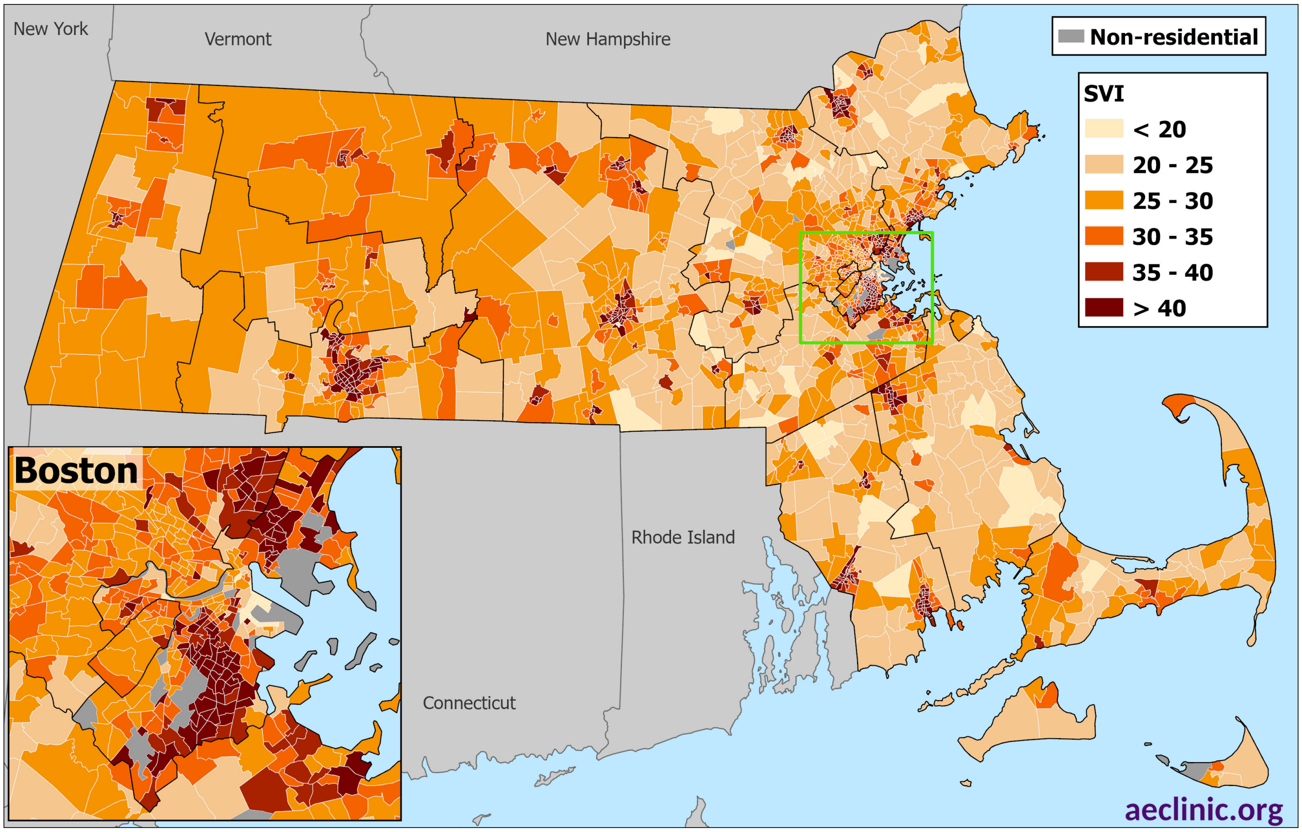
[50] For each census tract in Massachusetts, population shares for the ten vulnerable groups are converted into component indices, each ranging from 0 to 100/10 (or 10) in value. A higher score indicates a greater degree of vulnerability. The SVI is the sum of these component indices and ranges from 4 to 64.

Worcester. In Brockton, for example, 86 percent of the city population (approximately 44,000 people), are living in census tracts with an SVI score greater than 40 (for reference, an SVI score of 40 is higher than 83 percent of Massachusetts census tracts). Conversely, 39 municipalities (across urban and rural areas) contain one or more census tracts with an SVI score lower than 20.

Table 7. SVI measures

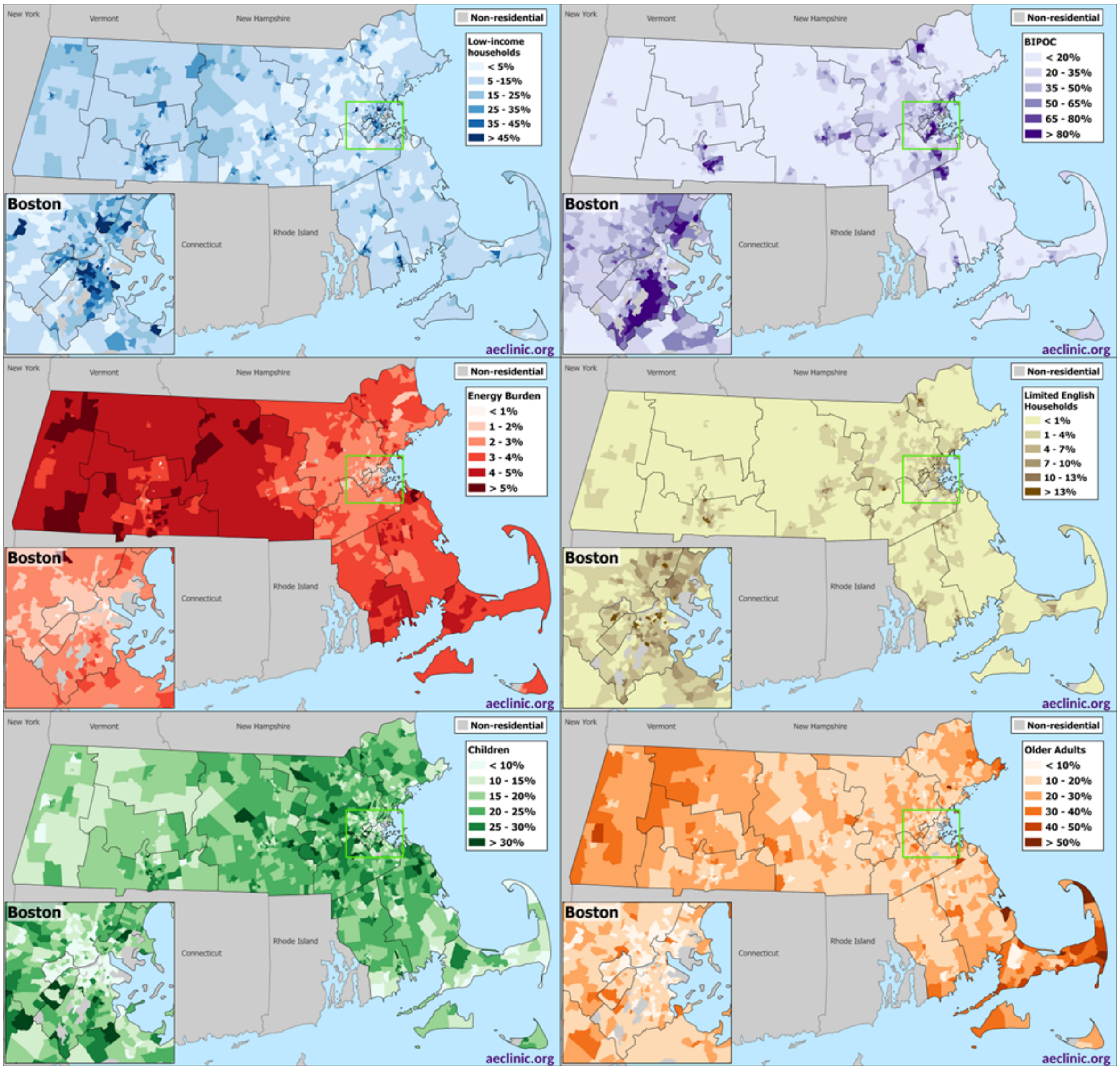
SVI measure	Description
Low-to-No Income	the share of the population that earns 150 percent or less of the federal poverty level
BIPOC	the share of the population that identifies as Black, Indigenous, or Persons of Color
Energy Burden	the average share of household income spent on energy costs
Limited English	the share of households that speak limited English
Children	the share of the population under the age of 18
Older Adults	the share of the population over the age of 65
Disabled	the share of the population that is disabled
Older Buildings	the share of occupied housing units built before 1960
Renter-Occupied Housing	the share of occupied housing units that are renter-occupied
Unemployed	the share of the labor force that is unemployed

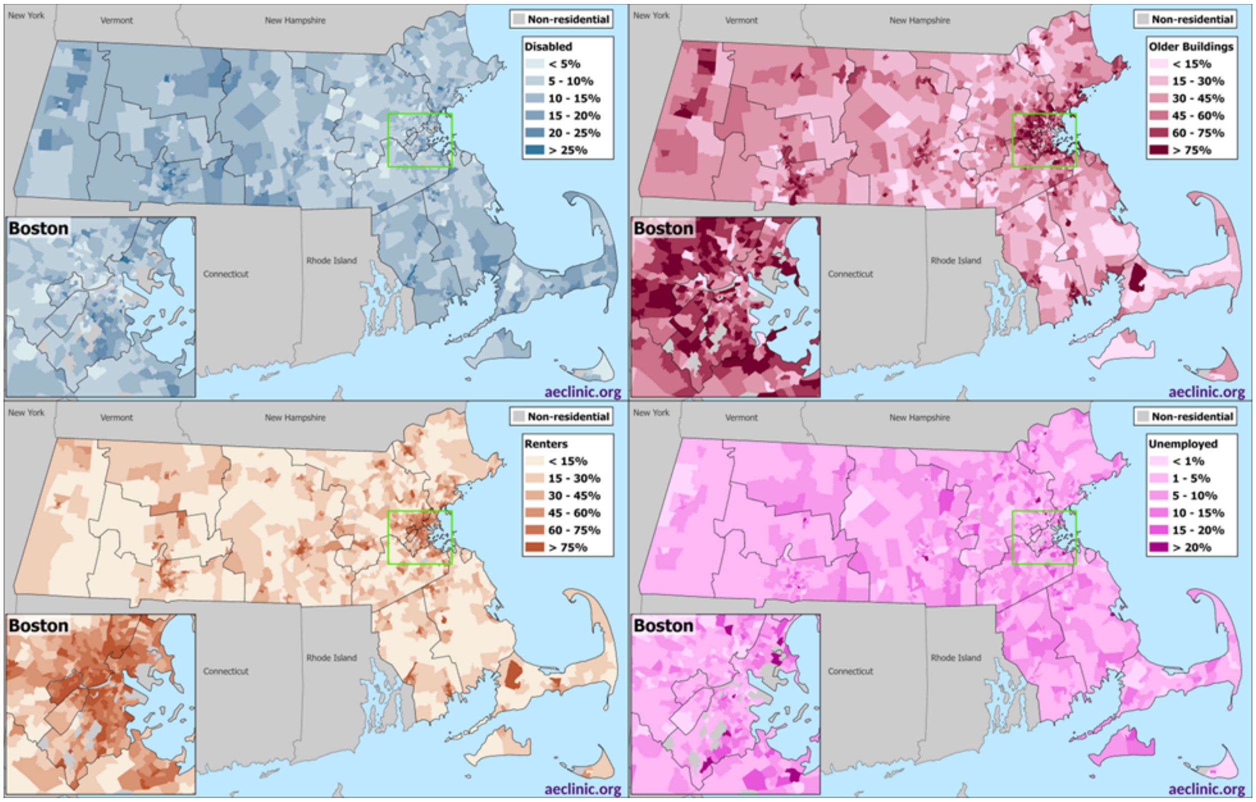
Figure 18. Massachusetts Social Vulnerability Index



Note: Non-residential census tracts are defined as those with fewer than 500 households. These tracts are not included in the SVI calculation.

Figure 19. Factors in the Massachusetts Social Vulnerability Index




New York
Vermont
New Hampshire
Non-residential
Disabled
< 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
> 25%
Boston
Connecticut
Rhode Island
aeclinic.org
New York
Vermont
New Hampshire
Non-residential
Older Buildings
< 15%
15 - 30%
30 - 45%
45 - 60%
60 - 75%
> 75%
Boston
Connecticut
Rhode Island
aeclinic.org
New York
Vermont
New Hampshire
Non-residential
Renters
< 15%
15 - 30%
30 - 45%
45 - 60%
60 - 75%
> 75%
Boston
Connecticut
Rhode Island
aeclinic.org
New York
Vermont
New Hampshire
Non-residential
Unemployed
< 1%
1 - 5%
5 - 10%
10 - 15%
15 - 20%
> 20%
Boston
Connecticut
Rhode Island
aeclinic.org

Technical Appendix

Figure 20. Modeling Approach

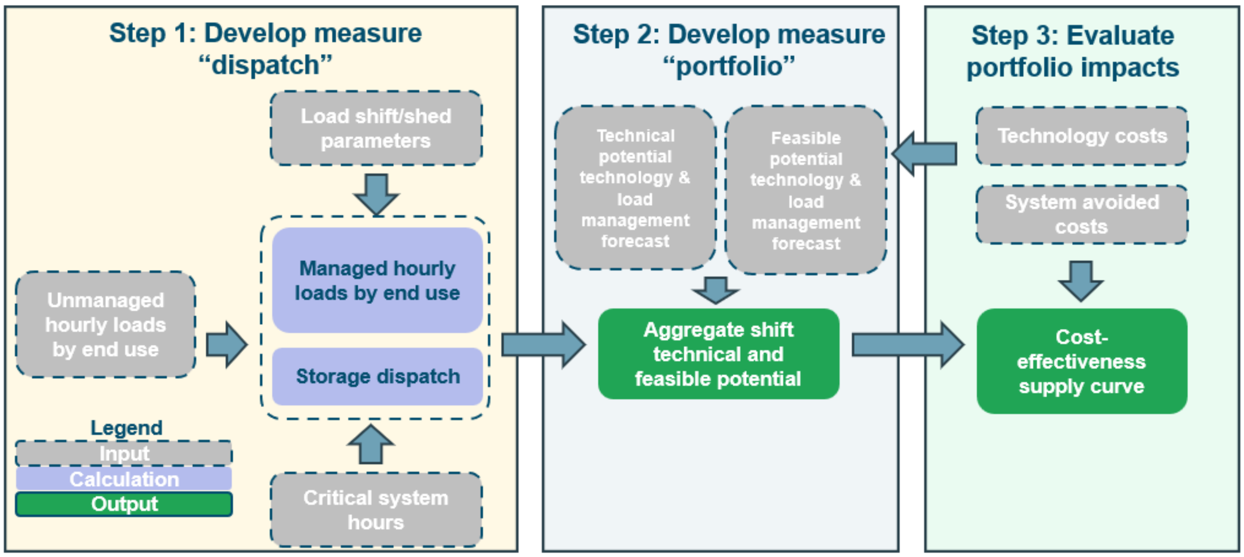


Table 8. Scenario Assumptions for Building Measures

Load Management Scenario			Incremental Growth			Accelerated Growth		
Year	**Units**	**Source**	2030	2040	2050	2030	2040	2050
Residential ccASHP	% of households	ISO-NE CELT Heat Pump Forecast (low) and CECP Phased Scenario (high)	3%	21%	44%	4%	32%	57%
Residential Hybrid HPs			12%	13%	11%	21%	24%	16%
Residential GSHP			1%	2%	5%	2%	9%	13%
Res Basic Shell (retrofit)	% of existing buildings	Mass Save (low) and CECP Buildings 2050 Technical Report (high)	30%	50%	65%	30%	50%	65%
Res Deep Shell (retrofit)			0%	0%	0%	3%	8%	13%

Stretch Code	% of new construction	Low Compliance Sensitivity	70%	70%	70%	90%	90%	90%
HVAC Flexibility	% adoption of equipment	Residential Baseline Study	60%	80%	90%	60%	80%	90%
	% enrollment in DR programs	Connected Solutions	30%	35%	40%	60%	70%	80%
	% realization during DR calls	Connected Solutions	55%	55%	55%	55%	55%	55%
WH Flexibility	% of electric WH load	Informed by LBNL	20%	40%	60%	50%	90%	90%
Appliances	% of appliance load	Informed by LBNL	10%	20%	30%	20%	30%	40%

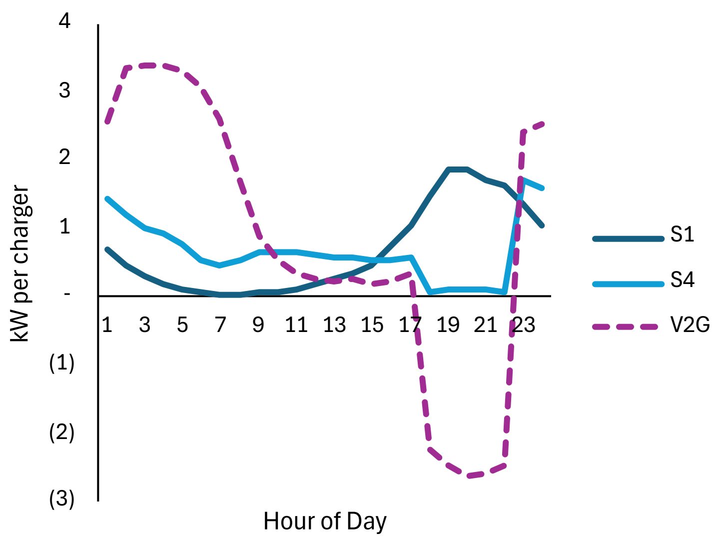
Table 9. Scenario Assumptions for Industrial, Transportation, and Storage Measures

Load Management Scenario:			**Incremental Growth**			**Accelerated Growth**		
Year	**Units**	**Source**	2030	2040	2050	2030	2040	2050
Industrial Process Loads	MW	ConnectedSolutions	162	272	382	202	340	477
EV Adoption	% of vehicles	ISO-NE CELT EV Forecast	7%	38%	66%	18%	68%	91%
LDV Managed Charging	% of electric vehicles	EVICC Assessment	15%	50%	75%	25%	45%	45%
LDV V2G			0%	0%	0%	0%	30%	50%
MHDV Managed Charging			95%	95%	95%	70%	5%	5%
MHDV V2G			0%	0%	0%	25%	90%	90%
BTM Storage	MW of installed capacity	National Grid ESMP (low) and CECP (high)	167	414	462	278	1,481	3,025

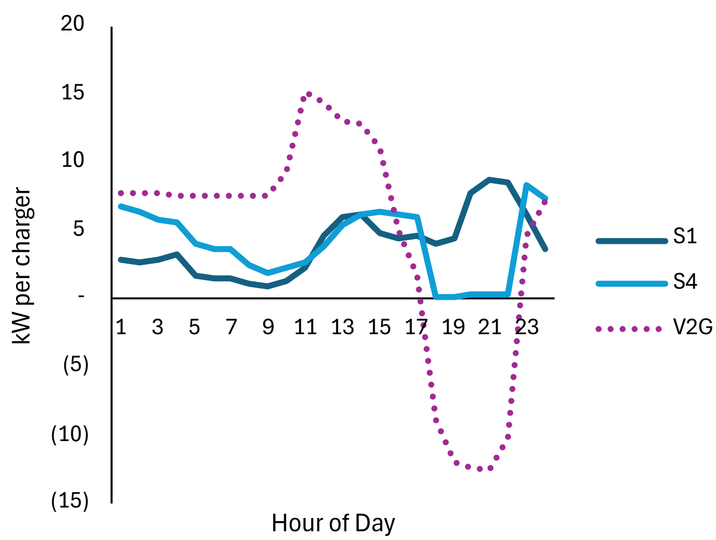
The following figure shows EV charging behavior assumed across vehicles and strategies.

Figure 21. V1G and V2G EV Charging Load Shapes

Light Duty Vehicle Charging



Medium- and Heavy- Duty Vehicle Charging



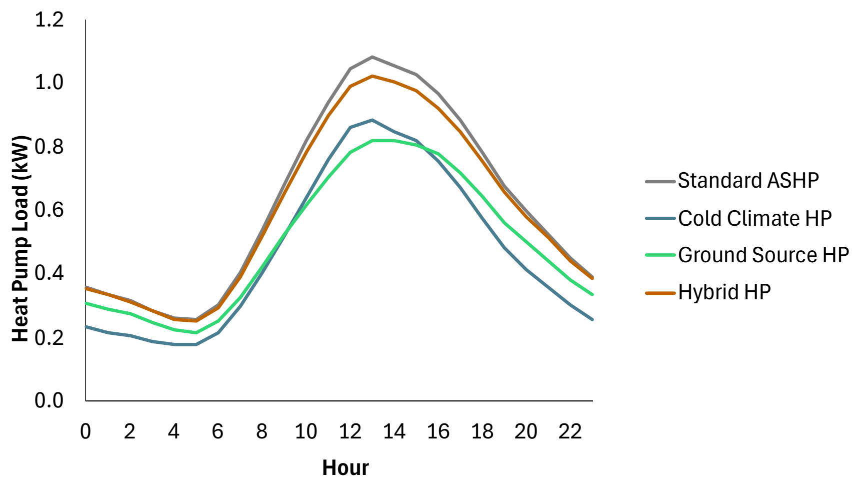
The following figure shows EV charging behavior assumed across vehicles and strategies. Figure 21 illustrates the EV charging load shapes used in this study. All profiles except V2G were developed for the Executive Office of Energy and Environmental Affairs (EEA) for the Electric Vehicle Infrastructure Coordinating Council (EVICC) Second Assessment, while the MHDV profiles were provided to EEA as a part of the Department of Energy's state technical assistance program. In both studies, the peak period is assumed to be 5-10pm. EEA scenario 1 (S1) represents unmanaged charging behavior, where drivers plug in their cars based on convenience, not price signals. EEA scenario 4 (S4) represents the technical potential of managed charging. In S4, 95% of all L1 and L2 chargers shift 100% of their peak-period load to off-peak. For fast charging, 10% of charger load during peak hours is redistributed evenly to off-peak hours.

For the scenarios in this study, these profiles were weighted based on scenario-specific inputs, and used directly, i.e., daily dispatch was dictated by these shapes rather than responding to critical system hours. The weighted profiles were applied to all study years. To get the total hourly load from EV charging, these per-charger load shapes are multiplied by the projected charger count in each scenario.

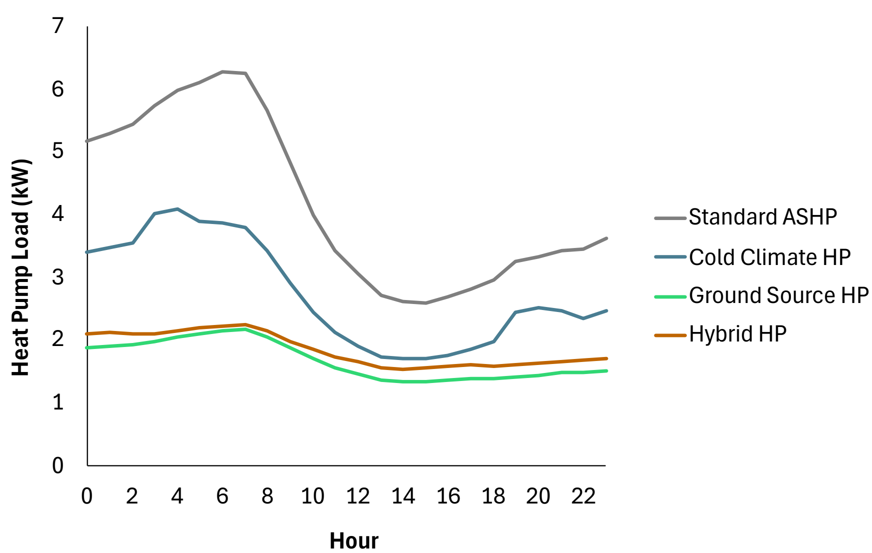
The figure below shows the electric heating load associated with different heat pump technologies.

Figure 22. Daily Seasonal Heat Pump Load Shapes

Summer



Winter



The heat pump load shapes used in this analysis were sourced from NREL's ResStock and ComStock datasets. Specific measures were used to represent hourly load profiles of standard ASHPs, ccASHPs, ground source heat pumps, and hybrid heat pumps,[51] in kWh per unit. These profiles reflect typical residential heat pump usage patterns and were applied to all study years. The total hourly load from heat pumps was calculated by multiplying the per-unit load shape by the projected number of heat pump installations in each scenario.

Cost Data Appendix

Table 10. Upfront and O&M Cost Data Sources

Measure	Source
Res HVAC Control	*Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources Through 2050, May 2024 ("LBNL DR Potential Study 2024")*
Res Cold-Climate Heat Pumps	*Cost estimates shared by MassCEC ahead of upcoming building electrification cost study ("MassCEC 2025")*
Res GSHPs	*MassCEC 2025*
Res Hybrid HP Control	*LBNL DR Potential Study* 2024
Res WH Control	*Incremental measure costs = 0*
Res Shell Upgrade, Light	*MassCEC 2025*
Res Shell Upgrade, Deep	*MassCEC 2025*
Res Stretch Code	*Literature review*
Res Appliance Control	*LBNL DR Potential Study* 2024
C&I HVAC Control	*LBNL DR Potential Study* 2024
C&I Cold-Climate Heat Pumps	*MassCEC 2025*
C&I Hybrid HP Control	*LBNL DR Potential Study* 2024
C&I WH Control	*LBNL DR Potential Study* 2024
C&I Shell Upgrade, Light	*MassCEC 2025*
C&I Shell Upgrade, Deep	*MassCEC 2025*

[51] The shapes shown above for hybrid heat pumps would apply for both the active "grid-enabled" hybrid heat pump that switches to gas backup usage during critical hours and the non-enabled hybrid heat pump that switches over based on cold temperatures, with a compressor lockout temperature of 5F.

C&I Stretch Code	*New Buildings Institute Analysis for DOER*
C&I Appliance Control	*LBNL DR Potential Study* 2024
LDV Charging	*No incremental cost*
MHDV Charging	*No incremental cost*
LDV and MHDV V2G	*Clean Energy Review: Bidirectional EV Chargers Review* *Tesla Powershare | Tesla Support* *Ford Charge Station Pro | Chargers.Ford.com* *Tesla Powerwall* *Smart Charge America* *Recharged L2 Charger* *Financing EV Home Charger Installation | Qmerit* *EV Charger Installation Calculator - EV Charging Calculator* *Installing Bidirectional Charging Solutions | Qmerit* *Quick Start to Electrifying Your School Bus Fleet* *Electric School Bus Charging 101, Electric School Bus Initiative* *How Much Does a Commercial EV Charging Station Cost? A Complete Breakdown - Charge Rigs* *Best EV Charging Stations for Fleet Vehicles - EVSE GEEK* *Electric Vehicle Blueprint for Twin Rivers Unified School District | California Energy Commission* *Fleet Electrification: Level 2 or DC Fast Charging? - Suppliers - Charged Fleet*
BTM Storage	*National Renewable Energy Laboratory, Annual Technology Baseline 2024*
Industrial	*LBNL DR Potential Study* 2024

Technical and Feasible Potential Appendix

Table 11. Load Shifted Out of Critical Hours, Technical Potential (MW)

Measure	2030 Summer	2030 Winter	2040 Summer	2040 Winter	2050 Summer	2050 Winter
Res HVAC Shift	444	80	12	304	0	351
Res ccASHPs	16	35	2	690	0	1020
Res GSHPs	3	16	0	123	0	166
Res Hybrid HPs	0	209	0	628	0	383
Res Hybrid HP Active Shed	0	236	0	736	0	430
Res WH Shift	182	129	11	685	0	725
Res Shell Upgrade, Light	683	74	19	370	0	310
Res Shell Upgrade, Deep	540	214	20	1056	0	874
Res Stretch Code	17	33	3	845	0	1819
Res Appliance Shift+Shed	265	143	6	526	0	550
C&I HVAC Shift	473	26	22	180	0	253
C&I ccASHPs	20	22	1	177	0	266
C&I Hybrid HPs	0	72	0	319	0	225
C&I Hybrid HP Active Shed	0	62	0	275	0	192
C&I WH Shift	27	20	1	56	0	58
C&I Shell Upgrade, Light	406	73	18	566	0	693
C&I Shell Upgrade, Deep	550	133	25	984	0	1197
C&I Stretch Code	13	6	1	86	0	162
C&I Refrigeration Shift	25	9	1	29	0	31
LDV V1G	819	318	64	3514	0	4471
MHDV V1G	28	10	4	177	0	343
LDV V2G	1378	528	106	5812	0	7426
MHDV V2G	65	24	8	415	0	808
BTM Storage	28	8	0	295	0	698
Industrial Shed	365	151	10	479	0	488

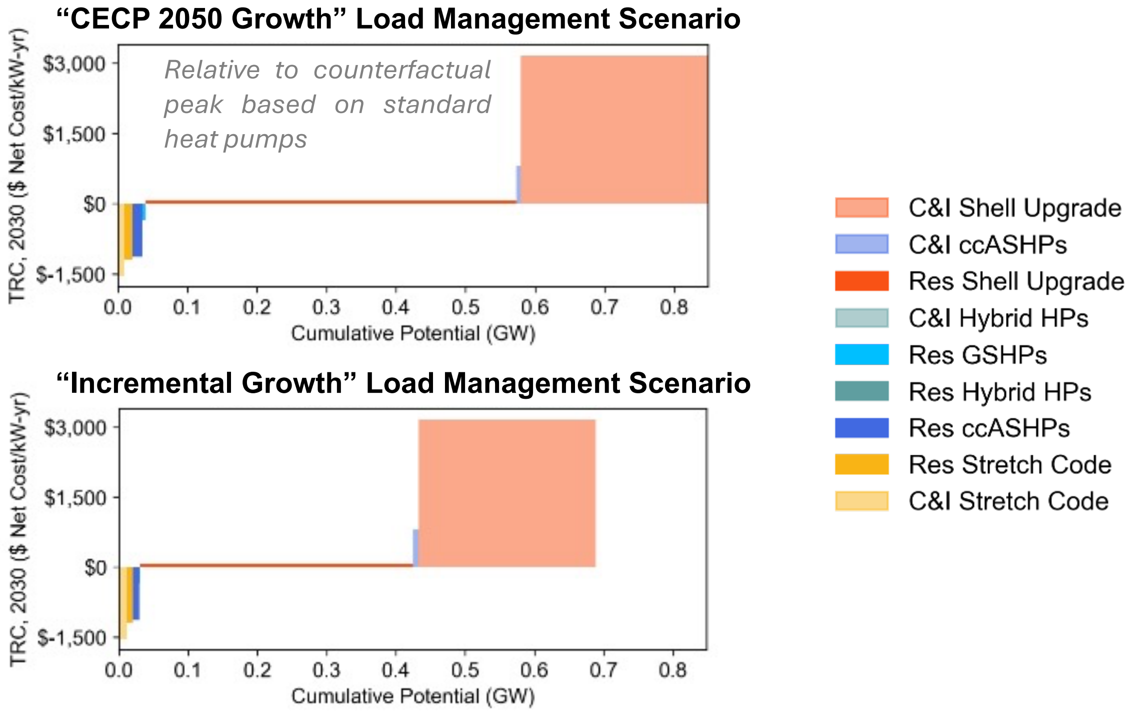
Table 12. Load Shifted Out of Critical Hours, Feasible Potential - CECP 2050 Growth Summer (MW)

Measure	2030 Summer	2030 Winter	2040 Summer	2040 Winter	2050 Summer	2050 Winter
Res HVAC Shift	112	17	4	99	0	153
Res ccASHPs	14	32	2	659	0	1034
Res GSHPs	4	27	0	302	0	403
Res Hybrid HPs	0	235	0	703	0	430
Res Hybrid HP Active Shed	0	50	0	248	0	190
Res WH Shift	91	64	10	616	0	652
Res Shell Upgrade, Light	533	28	20	247	0	289
Res Shell Upgrade, Deep	485	76	20	684	0	805
Res Stretch Code	12	23	2	591	0	1273
Res Appliance Shift+Shed	53	29	2	158	0	220
C&I HVAC Shift	74	3	6	49	0	96
C&I ccASHPs	7	7	1	151	0	254
C&I Hybrid HPs	0	158	0	573	0	374
C&I Hybrid HP Active Shed	0	27	0	152	0	126
C&I WH Shift	13	10	1	51	0	52
C&I Shell Upgrade, Light	269	26	15	352	0	579
C&I Shell Upgrade, Deep	317	46	19	606	0	997
C&I Stretch Code	9	4	1	60	0	113
C&I Refrigeration Shift	5	2	0	9	0	12
LDV V1G	205	79	61	3325	0	5725
MHDV V1G	36	13	7	383	0	744
LDV V2G	205	79	61	3325	0	5725
MHDV V2G	36	13	7	383	0	744
BTM Storage	153	53	9	279	0	666
Industrial Shed	95	42	4	213	0	302

Table 13. Load Shifted Out of Critical Hours, Feasible Potential – Incremental Growth (MW)

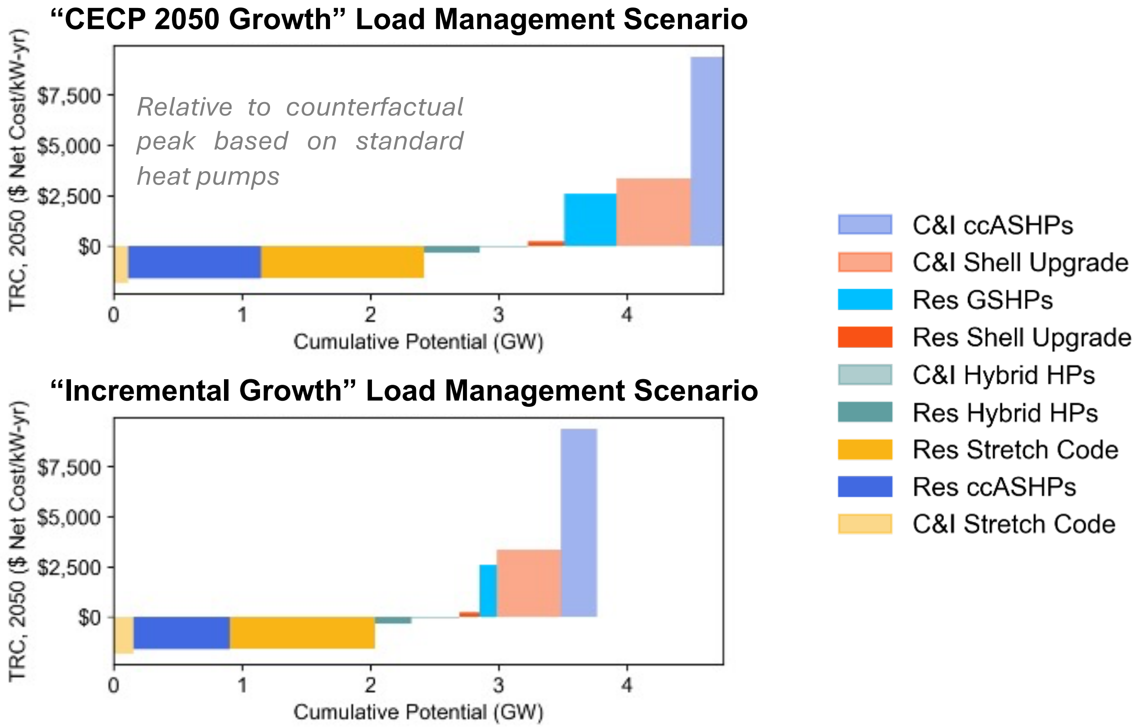
Measure	2030 Summer	2030 Winter	2040 Summer	2040 Winter	2050 Summer	2050 Winter
Res HVAC Shift	63	8	2	35	0	56
Res ccASHPs	9	22	1	383	0	748
Res GSHPs	1	8	0	78	0	140
Res Hybrid HPs	0	129	0	362	0	281
Res Hybrid HP Active Shed	0	14	0	63	0	61
Res WH Shift	36	26	4	274	0	435
Res Shell Upgrade, Light	394	15	13	109	0	153
Res Shell Upgrade, Deep	329	38	11	294	0	417
Res Stretch Code	8	16	1	402	0	1133
Res Appliance Shift+Shed	26	14	1	103	0	160
C&I HVAC Shift	38	2	3	25	0	53
C&I ccASHPs	8	9	1	155	0	284
C&I Hybrid HPs	0	148	0	520	0	377
C&I Hybrid HP Active Shed	0	13	0	69	0	64
C&I WH Shift	5	4	0	23	0	35
C&I Shell Upgrade, Light	256	23	14	285	0	496
C&I Shell Upgrade, Deep	298	41	17	487	0	848
C&I Stretch Code	12	5	1	75	0	156
C&I Refrigeration Shift	2	1	0	6	0	9
LDV V1G	48	19	19	1022	0	2555
MHDV V1G	4	1	0	6	0	7
LDV V2G	48	19	19	1022	0	2555
MHDV V2G	4	1	0	6	0	7
BTM Storage	94	38	6	299	0	307
Industrial Shed	76	33	3	171	0	242

Figure 23. 2030 Passive Measure Supply Curves



Notes: Weighted average of load reduction across top 200 of critical hours shown, where weights = contribution of each hour's load to total critical hour load across top 200 critical hours. Light shell retrofit costs shown above; CECP Growth scenario includes 3% of deep shell retrofits in existing buildings by 2030, with significantly higher capital costs than light shell retrofits.

Figure 24. 2050 Passive Measure Supply Curves



Notes: Weighted average of load reduction across top 200 of critical hours shown, where weights = contribution of each hour's load to total critical hour load across top 200 critical hours. Light shell retrofit costs shown above; CECP Growth scenario includes 13% of deep shell retrofits in existing buildings by 2050, with significantly higher capital costs than light shell retrofits.