DEMAND-SIDE SOLUTIONS TO WINTER PEAKS AND CONSTRAINTS

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RESEARCH REPORT
APRIL 2021

ACEEE
American Council for an Energy-Efficient Economy

Contents

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The **American Council for an Energy-Efficient Economy** (ACEEE), a nonprofit research organization, develops policies to reduce energy waste and combat climate change. Its independent analysis advances investments, programs, and behaviors that use energy more effectively and help build an equitable clean energy future.

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Acknowledgments

This report was made possible through the generous support of the Energy Trust of Oregon, National Grid, NYSERDA, TVA, the United Illuminating Company, and the U.S. Department of Energy. We also gratefully acknowledge the expert advice provided by Brian Bak (Duke Energy); John Black, Tim Costa, and Victoria Rojo (ISO-NE); Tony Bouza and Sven Mumme (DOE); Brenda Chew (SEPA); Stephen Cowell (E4TheFuture); Tom Eckman (formerly NPCC); Matt Gerhardt and Mary Sprayregen (Oracle); Danielle Goldberg, Pat Knight, Doug Hurley, and Jason Frost (Synapse); Freddie Hall (Burlington Electric); Tom Hines (Tierra Resource Consultants); Christy Intihar (BC Hydro); Emily Levin and Lauren Molino (VEIC); Claire Miziolek (Massachusetts Executive Office of Energy and Environmental Affairs); Ryan Jones, Trieu Mai, Andrew Parker, Dan Steinberg, and Eric Wilson (NREL); Matt Rusteika (Acadia Center); Charlie Schreier (Go Sustainable Energy); Hitesh Soneji (Olivine); Pam Sporborg (PGE); Anthony Teixeira (RMI); Elizabeth Titus (NEEP); Robert Weber (BPA); Jurgen Weiss (Harvard Business School); and John Wilson (Resource Insight).

We also thank our external reviewers: Dale Hoffmeyer (DOE), Asa Hopkins (Synapse), Dave Lis (NEEP), Ezra McCarthy (National Grid), Aven Satre-Meloy (LBNL), Peter Schaffer

(Energy Trust of Oregon), Maggie Shober (SACE), Priya Sreedharan (GridLab), and JJ Vandette (Efficiency Vermont). External review and support do not imply affiliation or endorsement. Last, we acknowledge the advice and internal review provided by Chris Perry, Jen Amann, Steve Nadel, Ed Rightor, Neal Elliot, Lauren Ross, and especially Rachel Gold, who played a leading role in launching this project and guiding it through its completion. We further recognize ACEEE staff Mariel Wolfson, Mary Robert Carter, Wendy Koch, and Ben Somberg for their editorial and communications contributions.

Suggested Citation

Specian, M., C. Cohn, and D. York. 2021. *Demand-Side Solutions to Winter Peaks and Constraints*. Washington, DC: ACEEE. www.aceee.org/research-report/u2101.

Executive Summary

KEY TAKEAWAYS

- While a small fraction of U.S. utilities and regions currently experience winter peak electricity demand, that number is expected to grow much larger over the next 10–20 years due to electrification, particularly of space heating through the deployment of air source heat pumps.
- Utilities and other program administrators can cost effectively mitigate winter peaks and constraints by drawing upon and scaling up the few existing programs that specifically target winter peak demand reductions through energy efficiency and demand response.
- Demand-side measures (DSMs) that reduce heating load offer the greatest potential for managing winter peak demand by a large margin over other DSMs. Intelligent load control and demand flexibility options can play a key role in further reducing peaks.
- Residential weatherization measures are likely to have the largest impact on reducing winter peaks, but improved cold-climate air source heat pump performance may be more important than weatherization under a high heat pump deployment scenario.
- Intelligent operation of heating equipment through residential smart thermostats, advanced rooftop controls, and energy information management systems can also reduce winter peak demand, to a lesser but still significant extent.
- Demand response options, including storage and managed electric vehicle charging, may offer cost-effective opportunities to meet anticipated high winter peak demand. Such solutions also align with efforts to decarbonize the economy as they avoid reliance on fossil fuel generation during peak periods.
- The possibility of using limited fossil backup could be valuable in terms of reducing the amount of electric capacity needed to deal with the most intense winter peak events.

BACKGROUND

The demand for electricity varies widely, both daily and seasonally. Meeting peak demand—that period of highest demand on the electricity supply system—is a primary challenge and function of electric utilities and grid operators. Peak demand for most electric utilities in the United States has historically occurred and continues to occur in summer, driven largely by hot weather and the resulting high demand for air-conditioning.

This picture is changing, however. While only a small fraction of U.S. utilities and regions currently experience winter peaks, that number is expected to grow much larger over the next 10–20 years (particularly in the later years of this period). This is primarily due to the increasing use of electric heat pumps for space and water heating as well as the rapid adoption of electric vehicles (EVs)—trends contributing to electrification of the economy to meet decarbonization objectives. Recent technological advances have improved the cold weather performance of heat pumps, making them viable replacements for fossil fuel heating equipment in cold climates.

In addition to increasing electric heating demand, extreme winter weather introduces constraints that can challenge the ability of grid operators to provide a reliable power supply. During the February 2021 polar vortex event, for example, cold temperatures in Texas froze natural gas pipeline equipment, prevented gas from flowing through those pipelines, froze coal piles, and iced over wind turbines. The combination of abnormally high demand and loss of generation did not surpass the state's peak summer demand, but nevertheless, the resulting constraints led to a situation in which supply was insufficient to meet demand. The result was days-long power outages and loss of life.

Electricity delivered during peak times is often obtained from comparatively expensive, polluting sources such as natural gas combustion turbines or oil-burning peaker plants. From multiple perspectives — including cost, environmental quality, and health — this makes it essential to find cost-effective, nonpolluting alternatives to conventional fossil fuel peaking generation.

Decades of experience have shown that energy efficiency and load management programs can reduce electricity demand at peak times. Through energy efficiency and load management, utilities can meet growing customer demand for electricity, thereby reducing the need to build new generation plants or expand electricity transmission and distribution systems. These demand-side alternatives can reduce costs for utilities and customers, reduce pollution, and improve system reliability. To date, such efforts to reduce peak demand have largely targeted summer rather than winter peak demand because the value of winter peak demand reduction has generally been low while summer peak demand reduction typically has high value. However, continuing and expanding customer energy efficiency, demand response, and storage programs can help avoid future winter peak demand problems as well, especially by advancing measures and technologies that yield large winter demand savings.

RESEARCH OBJECTIVES

Valuing energy efficiency and load management as resources to meet winter peak demand is relatively new. As a result, few utilities have programs that are designed specifically to reduce winter peak demand. This report characterizes the opportunity for demand-side resources to address potential winter peaks and constraints and provides examples of strategies and technologies utilities and market participants can use to address these challenges.

WINTER PEAK DEMAND: STATUS AND TRENDS

Peak demand for most utilities and regions in the United States occurs in summer. Where winter peak demands occur, they are generally driven by residential electric space heating loads. Utilities currently characterized as winter peaking are primarily in the Pacific Northwest; there are some individual winter-peaking utilities in the upper Midwest, New

England, and Southeast as well. Regions that are forecast to experience a shift toward winter peaks include the Northeast and mid-Atlantic. Some utilities in the Southeast may also experience this shift to winter peak demand.

DEMAND-SIDE OPTIONS TO ADDRESS WINTER PEAKS

The demand-side options for utilities to address winter peak demand and constraints can be divided into four main categories, the first three of which fall within the scope of this report:

- **Energy efficiency:** supporting the permanent reduction of electricity used for heating, primarily through improvements in thermal envelope performance and use of cold-climate heat pump technologies
- **Demand response/load management:** using intelligent, grid-interactive thermal control of buildings (e.g., smart thermostats) to provide load flexibility from sources like water heaters, EVs, and heat pumps by managing settings to shed or shift load away from peak periods
- **Energy storage:** drawing on electricity stored in distributed locations such as home battery systems, thermal storage, and electric vehicle batteries
- **Distributed energy generation:** directly supplying electricity to the grid through customer-sited photovoltaic systems and other types of micro-scale generators. Distributed generation needs to be combined with demand response due to the timing of winter peaks and the variability of solar photovoltaics.

Most utilities have experience with customer programs and services that provide some of these options. Such solutions can be less costly than supply-side alternatives, such as adding new generation or transmission and distribution infrastructure.

REGIONAL ANALYSIS — NEW ENGLAND

We modeled the impacts of demand-side measures (DSMs) on a simulated four-day winter peak event during a polar vortex in New England in 2040. We chose to analyze New England for several reasons, including the region's ambitious climate goals; its long record of successful customer energy efficiency programs; its cold winter climate; and readily available data on forecasts, customer energy use, and program impacts. We created three DSM packages with progressively increasing levels of efficiency and flexibility (which we labeled *standard*, *smart*, and *deep*). We then applied those packages to load forecasts that assume significant growth in the penetration of electric technologies such as heat pumps and EVs to ascertain how different combinations of measures can affect system peaks.

RESULTS

Our analysis shows that continuing current DSM programs in New England can have a large impact on reducing both total energy consumption and winter peak demand in a highly electrified future. In our standard electrification scenario, two measures in particular —thermal envelope improvements and better performance of cold-climate heat pumps— reduce peak residential and commercial load by 7%, which is roughly equivalent to the generation provided by 10 peaker plants.

Including a wider set of grid-interactive demand-side measures in the smart DSM package reduces peak demand by nearly 12% and delivers 23% more energy savings over a four-day peak period than the standard package.

Our deep DSM package, which contains an ambitious but plausible set of additional demand-side measures including deep retrofits, advanced rooftop controls, and energy information management systems, yields benefits that are even more dramatic: a peak reduction of 34% and 3.8 times more energy savings over a four-day period than the standard package. This deep package also demonstrates a considerable capacity to flatten the system load profile through the use of connected water heaters, deferred EV charging, and utilization of behind-the-meter storage.

CONCLUSIONS AND RECOMMENDATIONS

Our analysis shows that effective demand-side solutions exist to address winter peaks and are in place or can be applied when the value of reducing winter peak demand or addressing grid constraints is sufficiently high. In cold climates the most effective solutions are naturally those measures that either reduce heating loads or meet heating loads at high efficiency. Energy efficiency and demand response largely complement each other and can be most effective when integrated into comprehensive customer programs that yield both energy savings and load flexibility.

To foster and support DSM as a cost-effective means to address winter peak demand and constraints:

- Regulators/policymakers should create requirements for utilities to establish winter peak demand reduction goals in regions where winter peaks have the potential to surpass summer peaks and the benefits of demand-side solutions are greater than the costs of meeting winter peaks with more expensive buildout of generation resources and/or transmission and distribution systems.
- Regulators should require utilities to apply parity in integrated resource planning for both supply-side and demand-side options when considering new investments to meet winter peak demand.
- Utilities or other program administrators should include the values associated with winter peak demand reductions in screening and developing DSM programs if they are not already doing so.
- Utilities or other program administrators should expand residential weatherization and retrofit programs to increase participation and savings.
- Utilities or other program administrators should incentivize and promote adoption of high-efficiency and cold-climate heat pumps and support market transformation toward the most efficient models.

Glossary

ASHP — air source heat pump

CBECS — Commercial Buildings Energy Consumption Survey

ccASHP — cold-climate air source heat pump

C&I — commercial and industrial

COP — coefficient of performance

DER — distributed energy resource

DR — demand response

DSM — demand-side management (including energy efficiency and demand response)

DSMs — demand-side measures

EE — energy efficiency

EFS — Electrification Futures Study

EV — electric vehicle

GEB — grid-interactive efficient building

GHG — greenhouse gas

GSHP — ground-source heat pump

GWh — gigawatt-hour

HPWH — heat pump water heater

HVAC — heating, ventilation, and air-conditioning

ISO — independent system operator (similar to RTO)

ISO-NE — ISO New England

LCOE — levelized cost of energy

LCOSE — levelized cost of saved energy

LCSPD — levelized cost of saved peak demand

MW — megawatt

PV — photovoltaic (solar electric energy)

RECS — Residential Energy Consumption Survey

RTO — regional transmission operator (similar to ISO)

T&D — transmission and distribution

TOU — time-of-use

Introduction and Background

The demand for electricity varies widely, both daily and seasonally. Meeting peak demand—that period of highest demand on the electricity supply system—is a primary challenge and function of electric utilities. The entire utility system is designed, built, and operated to meet demand at all times with a high degree of reliability. Failure to do so can result in outages, which disrupt the economy and daily life. In addition, electricity during peak demand times is often obtained from comparatively expensive, polluting sources such as natural gas combustion turbines or oil-burning peaker plants.[1] This makes it essential to find cost-effective and nonpolluting methods to address peak electricity demand.

Peak demand for most electric utilities in the United States has historically occurred and continues to occur in summer — largely driven by hot weather and the resulting high demand for air-conditioning. This picture is changing, however, primarily due to increasing use of electric heat pumps for both space and water heating as well as the rapid adoption of electric vehicles (EVs). Displacement of combustion equipment such as furnaces, boilers, and water heaters that use fossil fuels (largely natural gas, propane, or heating oil) has the potential to increase —or already is increasing—winter peak electricity demand in some regions. While such growth has been small to date, electrification in conjunction with decarbonization of generation resources will accelerate this growth over the next few decades. In this report we examine how winter peak demand can be met by various demand-side measures (DSMs) as alternatives to increasing electricity supply or expanding transmission and distribution (T&D) infrastructure.

Decades of experience have shown that energy efficiency and load management programs can reduce electricity demand at peak times (Frick et al. 2020; York, Kushler, and Witte 2007). Through energy efficiency and load management, utilities can meet growing customer demand for electricity while reducing the need to build new generation plants or expand electricity T&D systems.[2] Energy efficiency and load management also can help optimize the use of renewable resources. These demand-side alternatives can lower costs for utilities and customers, reduce pollution, and improve system reliability (Relf, York, and Kushler 2018; Molina and Nowak 2016; Lazar and Colburn 2013). The past decade has witnessed a flowering of diverse demand flexibility resources capable of adjusting load profiles on sub-second to seasonal time scales, features particularly useful for accommodating variable supply-side resources like wind and solar (Bronski et al. 2015).[3]

[1] Typically the generation units used to meet peak demand may emit more pollutants than baseload units due to differences in operating efficiencies (heat rates), pollution control technologies, and fuel types.

[2] *Load management* is taking actions and making investments in technologies, primarily on the customer side of the meter, that reduce or shift electric power demand at specific times as measured in kilowatts (kW) or megawatts (MW). *Energy efficiency* addresses improvements in the performance of technologies that reduce energy use, measured in kilowatt-hours (kWh), while delivering the same outputs. Energy efficiency and load management can be complementary; each strategy can yield both energy (kilowatt-hour) and power (kilowatt) savings. *Demand-side management* is an umbrella term that includes both.

[3] *Demand flexibility resources* are technologies that can reduce or shift power demand (kilowatts) due to actions taken by customers or grid operators. They also include both customer-sited and utility-scale generation or storage technologies that can supply power to the grid quickly.

There is a great deal of technological innovation occurring in the utility industry to incorporate a rapidly growing and diverse set of distributed energy resources.[4] Such innovation leverages advances in communications, controls, and data technologies. As some utilities — especially those in climates with cold winters — experience growing winter electric demand, there is rising concern among system operators, utility regulators, and stakeholders about the ability of existing systems to meet peak demand and maintain reliability. This concern is even more pronounced when compounded by other winter-specific constraints, such as the failure of supply-side resources during periods of extreme cold.

WINTER PEAKS: GROWTH, DRIVERS, AND CONCERNS

Electrification—the process of replacing fossil-fueled end-use equipment with electric equivalents—is causing load shapes to shift throughout the United States, and in several cases it has been a driver of growing winter demand (Wilson and Shober 2020). To date this impact has been relatively small. However, state and local climate action plans and decarbonization road maps are beginning to recognize the critical role of electrification (e.g., Ismay et al. 2020). Depending on the rate at which this occurs, there is the potential for rapid increases in winter peak demand in some states and regions, such as New England (Goldberg et al. 2020).

Drivers of electrification include the conversion of fossil-fueled space heating, water heating, and transportation technologies to electric-powered versions like heat pumps, heat pump water heaters, and electric vehicles. Although these are often the lowest-carbon and most efficient technologies, their emergence will create new and growing load for electric utilities (Black & Veatch 2020).[5] This could create problems for meeting demand cleanly and cost effectively in the 2030s and beyond if growth is not mitigated over the next decade.

Deep or protracted periods of winter cold can introduce additional constraints that, while not strictly constituting peak demand, can have extremely adverse impacts on the grid. These events have frozen natural gas pipeline equipment, impeded the flow of gas through pipelines, frozen coal piles, and iced over wind turbines. Regardless of temperature, solar power is systematically reduced in winter due to cloud cover and lower solar flux. The resulting plunge in supply-side generation resources, when coupled with increased demand, can cause an energy imbalance that leads to grid failure in the form of a power outage. For example, the February 2021 polar vortex event led to a generation shortfall of 641 MW in the Southwest Power Pool (SPP), leading to the first rolling blackouts in its history (Eyocko 2021; SPP 2021).

There are important differences in the characteristics of winter and summer peak demands in cold winter climate regions, such as the Midwest and New England. Summer peaks are

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[4] *Distributed energy resources* (DERs) are customer-sited energy technologies that can reduce or shift power demand (kilowatts), reduce energy use (kilowatt-hours), or supply power to the grid. DERs include energy efficiency, load management (demand response), renewable energy (such as solar photovoltaic systems), and storage (batteries).

[5] ACEEE research shows that electrification of commercial buildings could cost effectively reduce site energy use by about 37% and greenhouse gas emissions by about 44% (Nadel and Perry 2020; Nadel 2016).

generally of short duration — typically a few hours during the day, often in late afternoon or (when solar resources are abundant) in early evening. Some winter peaks are of short duration as well, typically occurring in morning hours in places (like the Southeast) with high penetration of electric heating. However, some winter peak demands may extend over days during extreme winter events, such as polar vortices. These differences also create concerns about the ability of utilities to meet high winter power demand over extended periods. Winter power outages pose clear health and safety risks, especially if they occur during extreme weather conditions with very low ambient temperatures. Homes can become unlivable without electricity to operate home heating systems, and this is true even of homes relying on natural gas or other fuels as the heating source since most systems rely on electricity for controls, fans, and pumps.

For summer-peaking utilities, winter peak demand has generally not been a concern. Their generation capacity and associated T&D systems are sized to meet high summer peak demand and therefore have sufficient capacity to generate and deliver electricity to meet lower winter peak needs. Yet as winter peak demands grow, concerns may arise over whether existing generation resources and distribution networks can meet these demands. Winter peak power demand is generally coincident with low winter temperatures. Natural gas, a fuel used both for power generation and for onsite heating in residential and commercial heating systems, may suffer constraints on its ability to serve this dual use during extreme winter weather events. The existing natural gas transmission infrastructure may not have sufficient capacity to handle the volume of gas necessary to meet demand, or the natural gas supply networks may be constrained due to weather-related impacts on their capacity, resulting in shortages and high market costs for available supplies (EIA 2019b). Extreme cold weather also can affect coal generation plants due to freezing of coal piles and the resulting inability to feed generators. Wind generators may experience cutouts during extended periods of extremely low temperatures. Often the last marginal generation units brought into service are older, less efficient, dirtier, and expensive—characteristics that may increase costs and work against local greenhouse gas reduction goals.

Options for Addressing Increases in Winter Peak Demand

There are two primary ways to meet growing demand that will exceed available resources: (1) increase capacity, or (2) reduce demand. Increasing electricity capacity may require the addition of new generation plants or the purchase of power, if available, from wholesale markets. Reducing demand can be achieved by improving energy efficiency or managing customer loads to shift or lessen at specified times—collectively referred to as demand-side management (DSM). We explore and analyze DSM options in this report.

Specifically targeting winter peak demand reduction is largely a new twist for DSM. While energy efficiency programs have always had winter energy and winter peak impacts, those peak reductions generally have not been valued or set as program objectives. The rapid growth and inclusion of various distributed energy resources (DERs) with traditional grid resources is changing the system load profiles (timing and magnitude of demand throughout the day) and the mix of grid resources used to meet these loads.[6] In this report we explore the potential of DSM to serve as a DER that can address future winter peak demands in selected regions that are projected to become winter peaking as a result of electrification.

Research Objectives and Methodology

Research Objectives

The primary objective of this research was to characterize the opportunity for demand-side resources to address potential winter peaks and constraints, and to provide examples of strategies and technologies utilities and market participants can use in meeting these challenges. We examined drivers of winter peak and electrification scenarios in selected regions. Key issues considered in our analysis included:

- The scale and costs of electricity system constraints under different electrification scenarios
- Examples of successful winter peak demand-side strategies and programs
- Feasibility of demand-side options to meet higher winter peak demand
- Costs and benefits of such demand-side resources

There is great interest in electrification and strategies to manage its growth in ways that minimize system costs, but to date there is limited analysis of the extent to which demand-side solutions can support electrification. Our research was designed to address this gap.

Methodology

Literature Review

Our research included a robust literature review to assess the state of winter peak demand today and projections for winter peaks in the future. We examined the changing supply-side and demand-side conditions that will be drivers of winter peaks. Using available forecasts, we identified the regions in which winter peaks may become most pronounced.

The literature review identified the technologies that are expected to have the greatest impact on winter peaks. These include technologies that can increase electricity demand, such as space heating, electric vehicles, and water heating. They also include technologies that enable load shifting, such as electrochemical and thermal storage and demand response. We relied on end-use projections from multiple sources to characterize both the saturation and performance of these key end uses out to 2040.

Email Opt-In Survey

In order to collect additional information on relevant utility-led programs that address winter peak demand, ACEEE conducted a voluntary survey among contacts and affiliates in

[6] *Distributed energy resources* are "resources sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (as with energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. . . . Examples of technologies and services that are frequently included in definitions of DERs include distributed renewable energy generation, energy storage, microgrids, combined heat and power systems, demand response, electric vehicles, and energy efficiency" (Baatz, Relf, and Nowak 2018).

the utility industry. Respondents were asked to provide examples of former, current, and planned demand-side programs that are evaluated or expected to contribute to peak demand reduction in winter months. These responses were confidential and obtained solely for the purpose of providing a more complete picture of the types of demand-side strategies currently being used to address winter peaks. The survey questions are provided in Appendix D.

Expert Interviews

We supplemented our literature review and email survey with more than 20 in-depth interviews of experts with insight into the winter peaks issue. These experts were drawn from national laboratories, consultancies, utilities, academia, independent system operators (ISOs), and associated nonprofit organizations.

We collected foundational information including why the experts believe it is important to start thinking about winter peaks now, the benefits of doing so, and the worst outcomes if we do not. We asked them to identify any utility programs or pilots they were aware of that address winter peaks either directly or indirectly. Where examples were available, we asked about challenges for engaging customers in these programs, how the programs were developed, and what could make them successful. Additional topics we discussed included:

- Data sources, such as program evaluations, energy savings potential studies, load forecasts, and integrated resource plans
- Customer technologies with the greatest impacts on winter peaks
- The role of data, such as from advanced metering infrastructure (AMI), in winter peak management
- Conditions affecting customer reactions to winter peak programs
- Policy, regulatory, and market drivers to deploy demand-side measures most effectively to address winter peaks, including direct load control, dynamic rates, behavioral methods, wholesale market changes, EV managed charging programs, and building codes

Scenario Analysis

We quantified the potential for DSMs to address winter peaks through a regional analysis. While no single region is representative of the United States as a whole, we conducted a modeling exercise as an initial step to generate insights applicable to the remainder of the country. Our criteria for selecting a region included: (1) relatively high level and intensity of current and forecast winter peaks; (2) political and economic opportunity for DSMs to be deployed at scale to address winter peaks; (3) availability of historic and forecast data around energy use, weather, and avoided costs; and (4) stakeholder and sponsor feedback. We concluded that New England best satisfies this set of criteria. We focused specifically on 2040, a time by which the region is expected to become winter-peaking (Mettetal et al. 2020; Nadel 2016).

To conduct this regional analysis, we used two electrification scenarios. Each scenario specified the number of electrified end uses we expect to be installed in New England in

2040.[7] Winter peaks have historically accompanied periods of deep or extended cold, so we placed our electrification scenarios in the context of an historic, multiday weather event—a polar vortex that impacted New England and the upper Midwest in January 2019. Using a combination of data sources detailed below, we mapped our electrification scenarios and outside temperatures to an electric system load in ISO-NE.[8] We applied progressively more ambitious packages of DSMs to assess their impact on reducing energy consumption and shaving peak demand. We further assessed the costs of these approaches relative to the costs of meeting peak demand with traditional generation, transmission, and distribution resources.

Winter Peak Demand and Constraints: Status and Trends

CHARACTERISTICS AND DRIVERS

While grid operators use a variety of definitions for peak demand, it is generally accepted to be the maximum grid load during a specified period of time (EIA 2020b; Frick et al. 2019). Currently, most regions of the United States experience annual peak loads during the afternoons and evenings of the hottest summer weekdays, driven largely by residential air-conditioning in combination with other year-round loads.

Where winter peaks do occur today, they are generally driven by early-morning (e.g., 7 to 9 a.m.) residential electric space heating loads. Residential water heating represents a lesser but still significant contributor to winter peaks, along with other assorted residential appliances. A smaller bump in morning demand occurs about 1–2 hours after the morning residential peak, when commercial HVAC and lighting systems begin coming online for the day. A secondary bump in residential consumption often occurs after the workday, extending late into the evening.

The low temperatures that often drive winter peak demand can impose constraints on power generators as well. This has occurred numerous times over the last decade, including during the 2011 Southwest freeze, the 2017 "bomb cyclone," and polar vortex events of 2014, 2018, 2019, and 2021 (FERC and NERC 2011, 2019; Peltier 2014; Berardesco 2018; NERC 2014; Smith, Bosman, and Davey 2019; Niziol 2021). The impact of these events has been felt in the form of fuel shortages, spikes in energy prices, calls to shed load, rolling blackouts, and even loss of life (EIA 2019a; Whitmer 2019; BBC 2019; Caspani 2021; Grandoni 2021).

For most utilities, winter peaks are characteristically of shorter duration than summer peaks. During periods of deep cold, however, winter peaks can persist longer, occasionally lasting more than 20 hours (Wilson and Shober 2020). In the extreme case of the February 2021 polar vortex, the load curtailment in Texas due to winter peak constraints lasted 70.5 hours (Magness 2021).

[7] For more on these scenarios, refer to the "Electrification Scenarios" section or supporting details in Appendix A.

[8] ISO-NE is the regional grid operator that serves the six New England states of Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire, and Maine.

Figure 1 illustrates the difference in system load between summer and winter peak days. It shows three regions — ISO-NE, the Tennessee Valley Authority (TVA), and the Alberta Electric System Operator (AESO). As a summer-peaking system, New England currently sees summer load peak several gigawatts higher than winter peak. As a dual-peaking system, TVA has winter and summer peaks that are more comparable in height. In both cases, the summer load profile is characterized by a longer-duration peak in the late afternoon into evening, while the winter peaks express a two-peak feature. The relative heights of the two peaks are comparable, though the morning peak is higher in TVA and lower in ISO-NE. In contrast, in the Alberta market the load profiles during peak days for both summer and winter are considerably flatter, a feature more common to Canadian regions than those to the south.

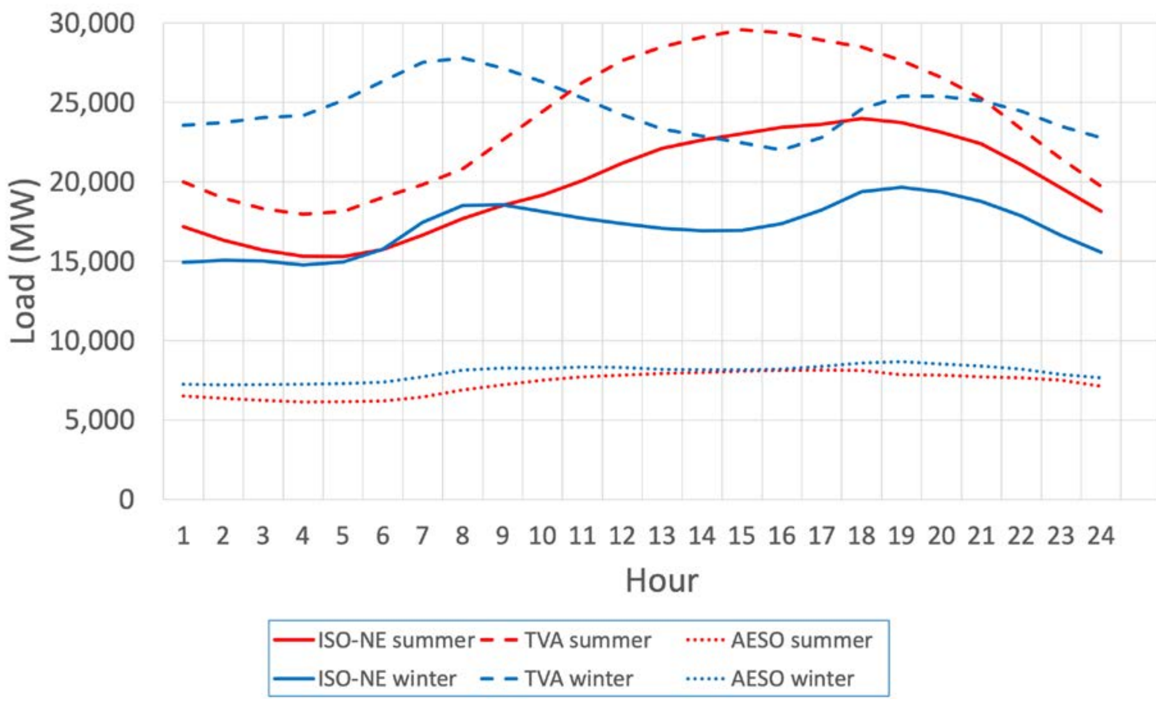

Figure 1. Load profiles for winter and summer days with the highest hourly seasonal system demands. ISO-NE plots are for a heat wave (August 20, 2020) and a polar vortex event (January 31, 2019). TVA plots are for August 13, 2019, and January 21, 2019. AESO plots are for July 23, 2019, and February 4, 2019 (ISO New England 2020a; Tennessee Valley Authority 2019; AESO 2020).

The persistence of or transition to a winter-peaking region is dependent on a number of factors including rate of electrification, load performance, electricity prices, prevalence of renewable energy generation, climate change, weather, and demand response capacity. Each of these factors contributes by reducing summer demand, increasing winter demand, or both.

A primary driver on the demand side is the growing adoption of cold-climate air source heat pumps (ccASHPs). These heat pumps add new electric load in winter through the replacement of fossil fuel heating systems (e.g., natural gas furnaces) and reduce cooling loads in summer because they are generally more efficient than typical central air conditioners.[9] In the past, heat pumps were uncommon in cold regions as their performance suffered at low temperatures. But in recent years, cold-climate heat pumps that are optimized for winter conditions have been developed, allowing heat to be provided at or below 0 °F. A similar conversion to electric heat pump water heaters will contribute additional winter load, albeit to a lesser degree.

On the supply side, evidence suggests that the polar vortex events responsible for historic supply-side constraints may worsen due to climate change (Cohen, Pfeiffer, and Francis 2018). Separately, growing amounts of solar generation serve to lower net load in summer—when solar energy is more abundant—relative to winter.[10] Furthermore, during early-morning winter peaks, if the sun is visible through cloud cover, it will be low in the sky and not able to generate as much electricity.

WINTER-PEAKING REGIONS

An independent system operator or regional transmission operator (ISO/RTO), a region, or a utility may be referred to as summer or winter peaking depending on whether its annual system electric demand is greatest in the summer or winter months. Shoulder seasons of spring and autumn, by virtue of their more moderate temperatures, usually do not experience hours of peak system demand.

There is no formal definition for what constitutes a summer- or winter-peaking region or service territory, nor is there a requirement for utilities to identify themselves as one or the other in regulatory filings. For example, it is possible that in a median year a region will see a summer peak, but during a year with certain conditions—like an extreme cold weather event—it may experience a winter peak. Six of these dual-peaking utility systems currently exist in the southeast United States (Wilson and Shober 2020).

A region's seasonal peaking status can be evaluated using a single annual load trend or by considering a "top 100 hours" approach, in which the 100 hours with the highest system demand are collected and the number that occur in summer and winter are compared. Regardless of approach, extreme conditions in any year can skew this determination, making multiyear assessments more appropriate for understanding the average properties of a region. In terms of forecasting, distributions of potential seasonal peak values can be generated and reported using a 50/50 or 90/10 format indicating, respectively, a 50% or a 10% chance that load will exceed the reported amount (e.g., see Black and Rojo 2019).

Current Winter-Peaking Regions

A number of utilities in the United States and Canada currently experience peak loads in the winter. For the most part, these utility regions are dominated by the need for residential heating during cold weather. Examples include Otter Tail Power (Minnesota), Washington

[9] Heat pumps can provide both heating and cooling by moving heat in air from outdoors to indoors or vice versa. Heat pumps operate more efficiently when the difference between indoor and outdoor temperatures is low. Recent improvements in technology have enabled heat pumps to provide efficient heating services at lower temperatures. For this reason, these more modern devices are often referred to as "cold-climate" heat pumps.

[10] Net load is the amount of total system demand minus that which is provided by non-dispatchable resources, usually solar and wind energy.

Electric Cooperative (Vermont), and many Canadian utilities such as BC Hydro, NB Power, and Nova Scotia Power (Otter Tail Power Company 2016; WEC 2014; BC Hydro 2013; Énergie NB Power 2017; Nova Scotia Power 2019).[11] Winter peaks are also present in much of the Pacific Northwest, partially due to a milder climate that mitigates peak summer demand. The overwhelming percentage of top 100 peak hours in Washington State occur in winter, with percentages in Montana and Oregon following close behind. Some regions of the Pacific Northwest are moving toward dual-peaking status, with increased regional penetrations of air conditioners (PSE 2020; PGE 2019; Mai et al. 2018; Bonneville Power Administration 2018).

While the majority of the Southeast's peak hours still occur in summer, the region contains both winter-peaking and dual-peaking territories where residential space heating remains the dominant winter-peaking load. Although other climates, like the Northeast, experience colder winters on average, a greater portion of their heating demand is met by fossil sources, whereas in the Southeast a greater portion of space heating load is met with electric resistance heating, leading to higher winter system loads. Southeastern utilities with winter- or dual-peaking components include Santee Cooper, Seminole Electric, TVA, Cooperative Energy, Lakeland, JEA, and (to a lesser extent) Duke Energy Progress (Wilson and Shober 2020).

Regions Forecast to Become Winter Peaking

Given the variety of factors that influence a region's transition to winter peaking, it can be helpful to use internally consistent electrification scenarios to clarify the range of potential outcomes. The best set that we discovered (and which we will use extensively in this report) comes from the National Renewable Energy Laboratory's (NREL) Electrification Futures Study (EFS), a multiyear project exploring the impacts of widespread electrification of all U.S. economic sectors (NREL 2021a; Mai et al. 2018). The EFS has produced a set of three demand-side scenarios—low, medium, and high—that reflect progressively increasing levels of electrification through 2050.

The EFS projects that many states will trend toward becoming winter peaking by mid-century. The level of this change depends on the amount of electrification occurring during this period. Figure 2 shows the EFS's state-by-state projections for 2050 under its three electrification scenarios.

[11] Given the importance of residential load as a driver, winter peaking is more common in rural electric cooperatives (which have relatively higher ratios of residential to commercial and industrial load), all else being equal.

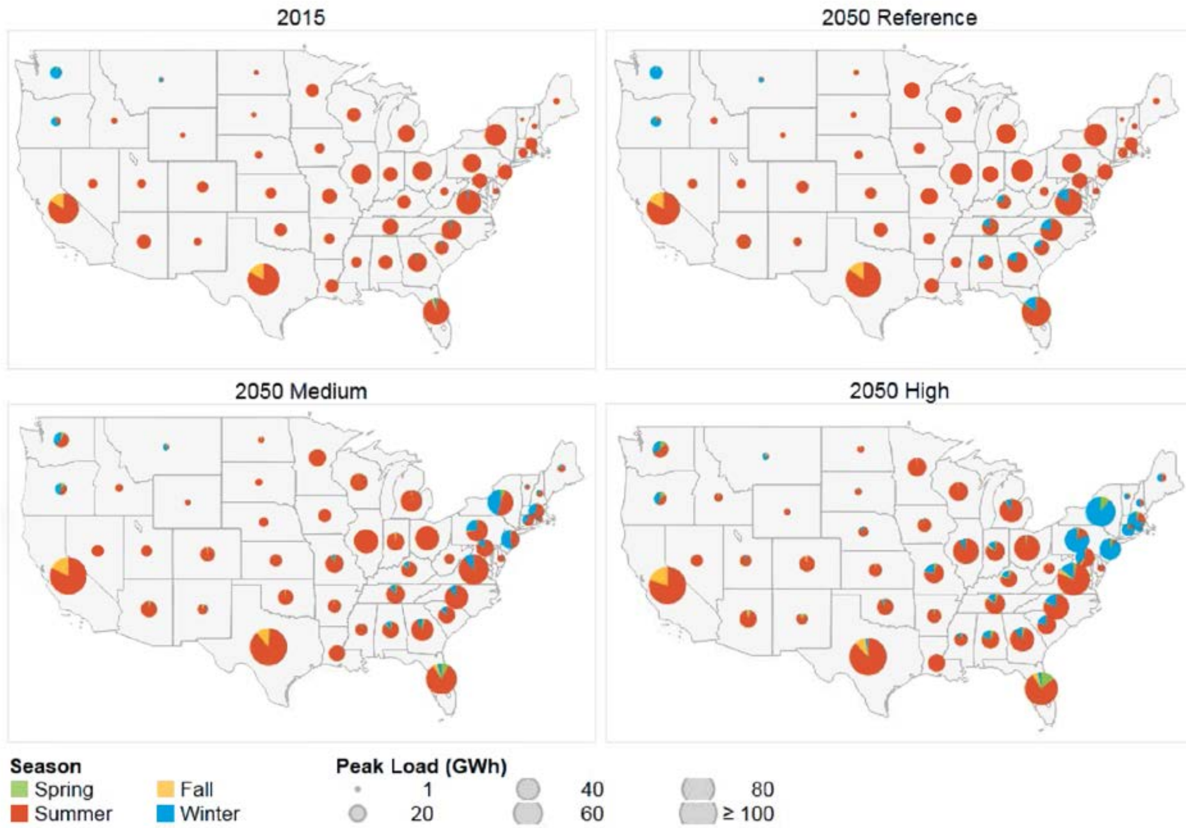

Figure 2. Distribution of peak load hours in 2015 and 2050 from the Electrification Futures Study. According to the *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, "The size of the pie charts corresponds with total electricity demand (GW) during the top demand hour. The pie wedges show the seasonal distribution of the top 100 hours with the highest demand by state. Seasons are defined along monthly groupings: summer includes June, July, and August; fall includes September, October, and November; winter includes December, January, and February; and spring includes March, April, and May. Moderate technology advancement projections are shown. Data shown, including 2015 data, are based on modeled estimates." (Mai et al. 2018)

According to the EFS, in 2050 under a reference (i.e., relatively low electrification) case, the Pacific Northwest remains winter peaking, while the percentage of winter-peaking hours in Southeastern states grows to about 20%. Under a medium electrification scenario, the percentage of winter-peaking hours in the Pacific Northwest is expected to experience a modest drop, while the Northeast states will see winter-peaking hours grow to about 30% of the top 100. In the highest electrification scenario, EFS predicts that the mid-Atlantic—especially New York, New Jersey, and Pennsylvania—will become predominantly winter peaking, with the number of top 100 load hours in the Northeast that will occur during winter increasing significantly (Mai et al. 2018).[12]

We caution the reader, however, that these conclusions are only a snapshot of what the future of winter peaks may look like in the United States. For example, a region where summer peak is only slightly higher than winter peak may seem overwhelmingly summer peaking through the lens of the top 100 hours but could appear more balanced in an inspection of a larger number of hours. Moreover, the saturation, performance, and load

[12] According to its 2020 Integrated Resource Plan, the Virginia Electric and Power Company (aka Dominion Energy) is already projecting that it will be a winter-peaking utility through at least 2035 (Dominion Energy 2020).

shapes of electrified end uses three decades from now are difficult to predict. This analysis also does not account for winter constraints resulting from unintended loss of generation. While figure 2 may be helpful in building up some intuition on the matter, additional research with robust sensitivity analyses will be needed to better ascertain how winter peaks will evolve around the country.

SUPPLY-SIDE OPTIONS FOR MEETING WINTER PEAKS AND CONSTRAINTS

The conventional resource planning approach to rising peak demand is to add new generation and/or extend transmission to import supply-side resources from a larger geographic area. As the grid decarbonizes, a growing share of generation (in both relative and absolute terms) will be met by variable energy resources like solar and wind. During periods of system peaks, today's fossil-fueled marginal units — like simple cycle natural gas, diesel, or even coal-fired peaker plants — are likely to be joined by flexible, low-carbon resources. These include storage (e.g., electrochemical batteries, pumped hydropower) and lower-carbon fossil fuel replacements like hydrogen fuel cells and renewable natural gas. Many of these low-carbon alternatives require substantial investment and development to become cost competitive with conventional generation. The cost to deliver these resources will fall largely on ratepayers.

Periods of extreme cold will challenge the supply-side approach, however. Wind turbines can be rendered inoperable due to ice and brittle components, and coal- and natural gas-fired power plants may experience fuel shortages or forced outages at very low temperatures (Tomich 2019). The North American Electric Reliability Corporation's (NERC) operational risk assessments identify these conditions as potential grid reliability risks, particularly near large load centers with limited transmission import capability. Absent other changes to the power system, high winter demand for natural gas can potentially exceed regional supply and delivery capacities, increasing a fuel assurance risk (NERC 2019). Such weather-related supply shortages occurred across the entire midwestern United States and particularly within the Electric Reliability Council of Texas (ERCOT) during the winter of 2021, leading to long-term power outages across the service area.

Demand-Side Resource Options to Address Winter Peaks and Constraints

Most utilities have experience with customer programs and services that provide some energy efficiency, demand response, or energy storage options. For example, many utilities employ demand response programs for air conditioners, automatically cycling or powering down units during a few peak hours in the summer. Fewer have experience with demand response and other load-control technologies to specifically address winter peaks. Some technologies, such as heat pumps and EV batteries, perform differently at lower temperatures. Consumer behavior may also vary in the winter. For example, while demand response strategies have been demonstrated to effectively reduce peaks in both summer and winter, both technologies and consumers respond differently on very cold days from how they respond on very hot days (Kiliccote, Piette, and Dudley 2010).

Energy efficiency is widely understood to be a least-cost grid resource option for purposes of integrated resource planning in states such as Indiana, Colorado, and California and in regions such as the Pacific Northwest. Grid planners looking to address winter peaks and constraints should be aware of the range of demand-side options available. These include familiar solutions like weatherization and efficient appliance replacements as well as newer technologies like smart thermostats, battery storage, and managed EV charging. This chapter looks at a variety of demand-side applications across customer sectors, grid regions, and technology types and examines the ways in which these end-use applications can be employed to address winter peak demand and system constraints.

Demand-side resources are not always treated equally in planning (Wilson and Biewald 2013). If policymakers and grid planners are not properly valuing and accounting for the benefits of energy efficiency and demand response, it may lead to overbuilding generation and transmission resources. This increases ratepayer costs and can contribute to a longer and more expensive transition to a carbon-free grid. For example, in the Southeast (a dual-peaking region) most utilities account for energy efficiency only as a reduction in the load forecast and may not value it as highly as a grid resource capable of large, reliable contributions to meeting system demand (Frick and Relf 2020). This is a region that has historically underinvested in efficiency compared with elsewhere in the country (Berg et al. 2020; Relf et al. 2020). If utilities and regulators fully account for the value and benefits of DSMs for both energy and capacity, they may be able to deliver least-cost solutions that can lower prices for end users while facilitating a smooth transition to a low-carbon future.

To better understand how utilities are currently using DSMs to address winter peak, ACEEE compiled program examples through primary research, a survey of utility program managers, and interviews with program administrators.[13] We received 19 survey responses from 8 of 10 U.S. grid regions, Canada, and Europe.[14] Respondents reported using technologies like connected thermostats, efficient appliances, weatherization and thermal insulation, energy storage, behavioral incentives, and time-of-use rates. Seventy percent of program examples addressed the residential sector, although several programs addressed multiple sectors. The majority (58%) of programs in the survey were reported as currently ongoing, while around a third (32%) were still in the planning phase.

In the following sections we present a sample of utility DSM programs with the potential to mitigate winter peaks across end uses. These represent a variety of end-use opportunities applicable in multiple grid regions.

SPACE HEATING

Heating is one of the largest categories of energy end use in the residential sector, with heating across all fuel types accounting for 43% of energy consumed on a Btu basis in residential buildings (EIA 2018). Heating is currently provided by a variety of technologies

[13] The survey questions are provided in Appendix D.

[14] Grid regions are distinct but interconnected markets for electricity that are run by an independent system operator (ISO) or regional transmission operator (RTO). There are seven primary ISO/RTOs in the continental US: ISO-NE (New England), NYISO (New York), PJM (Mid-Atlantic), MISO (Upper Midwest), SPP (Central Midwest), ERCOT (Texas), and CAISO (California). In addition, we considered three geographic areas that lack a centralized system operator: the Southeast, Southwest, and Pacific Northwest.

(e.g., boilers, furnaces, electric resistance) powered by a diverse set of fuels including electricity, natural gas, propane, oil, and wood.

As states and utilities pursue their decarbonization goals, one of the most important strategies will be the replacement of conventional heating technologies with highly efficient electric air source heat pumps (ASHPs). Electric heat pumps work by moving heat from outdoors to indoors, a process that requires less energy than generating heat directly.[15] Current heat pumps models exhibit vastly improved cold-climate performance relative to earlier versions and are becoming increasingly cost competitive with other home heating technologies (Nadel and Perry 2020; Billimoria et al. 2018).

The impact of ASHPs on winter peaks depends on the technology they displace. Installing an electric ASHP to replace another electric heating system — especially one operating through electric resistance — is likely to deliver energy savings and decrease electricity demand. Installing an electric ASHP to replace a fossil-fueled heating system will shift demand from those fossil fuel networks (i.e., natural gas, propane, heating oil) to the electric grid. While this transition is likely to save energy overall, it will increase electricity demand specifically.

Providing incentives for efficient space heating is critical for mitigating the sector's contribution to peak demand. In the South Atlantic region, for example, Duke Energy Carolinas reports that space heating accounts for about 70% of winter morning peak energy use in an average residential home, much of that coming from electric resistance heat (Duke Energy 2020a). The high efficiency of new ASHPs, along with their potential as a low-carbon home heating solution, has led many utilities and program administrators to offer incentives for converting home heating to this technology. Several examples of these programs are provided in table 1.

Aside from air source heat pumps, alternative heating technologies show promise as carbon-neutral home heating solutions. Geothermal systems, including ground-source heat pumps (GSHPs), take advantage of relatively stable temperatures underground to provide both heating and cooling for residences and commercial businesses. This allows consistent temperature control even during extreme weather events such as those that drive winter peaks. A recent feasibility study, highlighted in table 1 below, demonstrates the potential for this type of heating to be deployed on a neighborhood level. Although small-scale applications of these technologies are often costly for individual homeowners, deploying them across larger numbers of homes and businesses can reduce the cost for each individual participant and deliver increased value to homes and utilities.

[15] Heat pumps can move heat from indoors to outdoors as well, making them an efficient option for air-conditioning.

Table 1. Space heating program examples

Program administrator	Grid region	Program name	Description
Nova Scotia Power (NS Power)	NBSO	Heat Pump Financing Program	Homeowners may receive on-bill financing for ENERGY STAR®–certified heat pumps. Participating contractors help customers complete a credit application and perform the installation following approval from NS Power. Financing (installation and taxes included) is offered at 7% per year for a term of 3–10 years, after which ownership transfers to the homeowner. To date, 44% of conversions have been from all-electric heating systems. An evaluation study of the program is underway. Preliminary results indicate that the heat pumps (including less-efficient models installed earlier in the program) add approximately 500 kWh/month in winter and 140 kWh/month in summer. During the seven coldest days in 2020 (average temperatures all below –11 °C), heat pump maximum demand and heat pump coincident peak demand were about 1.7 kW and 1.3 kW per customer, respectively.[16]
Efficiency Maine Trust	ISO-NE	Residential & Commercial Heat Pump Rebate Program	To help Maine achieve its decarbonization goals of a 45% reduction by 2030 and 80% by 2050, the legislature and public service commission directed Efficiency Maine Trust (EMT) to provide rebates for high-efficiency heat pumps in the residential and commercial sectors. The program offers up to $1,000 for an indoor residential unit or $1,250 for certain income-qualified households, with the size of the rebate based on the heat pump's efficiency. Commercial customers can receive up to $500 per unit and a total of $1,250 in rebates for multiunit systems. As of the end of FY19, this program had successfully installed about 45,000 units, with a goal of installing an additional 100,000 by 2025, making this one of the largest heat pump programs in the United States. The program is funded through multiple sources, including revenues from the Regional Greenhouse Gas Initiative (RGGI), funds from the ISO-NE Forward Capacity Market, and a system benefits charge on retail electricity. Winter peak management is not a primary focus of this program.
NYSERDA	NYISO	Comfort Home Pilot	Starting in the fall of 2019, the New York State Energy Research and Development Authority (NYSERDA) began offering targeted heating and cooling load-reduction improvements in coordination with heat pump conversions in existing single-family homes. This pilot was designed to help meet New York State's objective of achieving 3.6 TBtu of end-use energy savings through accelerated adoption of heat pump technologies. By combining energy audits, air sealing, and custom home energy solutions with heat pump conversions in a holistic system, NYSERDA aims to streamline the customer acquisition and retention process and deliver higher savings per unit converted. Another intended goal is to reduce the required size of heat pumps by lowering the overall heating load, in order to mitigate home heating demand during winter peaks alongside electrification deployment. Evaluation results are not available from this program.

[16] Coincident peak refers to the demand of an end use during the interval that the electric system demand peaks.

NYSERDA	NYISO	NYS Clean Heat	Utilities in the NYS Clean Heat program offer incentives for air source and ground-source heat pump conversions in single-family homes. These utility incentives are paired with federal investment tax credits and on-bill financing (where available) to reduce the upfront costs to the homeowner. Evaluation results, including winter peak savings results, are not available from this program.
HEET MA	ISO-NE	GeoMicroDistrict Feasibility Study	Massachusetts utilities are exploring the feasibility of constructing a larger-scale geothermal system that would provide temperature control across an entire neighborhood — a "GeoMicroDistrict" — and replace natural gas heating with a low-GHG alternative. While not winter peak specific, these pumps are highly efficient: Total energy required to operate a neighborhood-level system is estimated at 15% of the total energy required for individual heat pump units. The study examined the technical and cost feasibility of neighborhood-scale GSHP in residential and mixed-use neighborhoods and communities. The technical potential study found that a closed-loop vertical GSHP system could meet 100% of the heating and cooling needs in low-density residential and medium-density mixed-use neighborhoods and 92% in medium-density residential areas. Per-unit costs for conversion and maintenance were lowest in medium-density mixed-use neighborhoods, at around \$750–\$6,500 for residential and \$10,500–\$77,000 for commercial. Based on the feasibility study, Massachusetts utilities advanced two GeoMicroDistrict pilots in December 2020.

Sources: Nova Scotia Power 2021; Nova Scotia Utility and Review Board 2019; Efficiency Maine Trust 2020; Nadel and Perry 2020; Schryer et al. 2020; NYSERDA 2020a; BuroHappold Engineering 2019; Shemkus 2020

WATER HEATING

Water heating accounts for 19.1% of all residential energy consumed on a Btu basis in the United States (EIA 2018). As with space heating, several different water heating technologies exist, including gas-powered, electric resistance, and heat pump (HPWH). Water heating can be a significant driver of winter peaks because its times of maximum usage (mornings and evenings) often coincide with system peak demand. In addition, inlet water is colder in winter, requiring more energy to raise its temperature for use in homes or commercial buildings. One method of addressing water heaters' contribution to peak demand is by replacing inefficient electric resistance water heaters with high-efficiency heat pump water heaters.

In addition to improving the efficiency of water heating, this technology is well suited to provide grid services through remotely controllable devices. Fleets of water heaters remotely controlled by a utility or third party can shift their demand away from a winter peak with little to no impact on building occupants. While heat pump water heaters are generally more efficient and provide greater savings continuously, less-efficient electric resistance water heaters — by virtue of their greater responsiveness and higher load factor — are better equipped to provide rapid demand response (Podorson 2016). Several utilities and program administrators offer incentives and programs for highly efficient heat pumps and grid-interactive water heating. Examples are presented in table 2.

Table 2. Hot-water heating program examples

Program administrator	Grid region	Program name	Description
Great River Energy	MISO	Water Heating Peak Load Reduction & Load Shifting Program	Great River Energy, an electric cooperative utility in Minnesota and North Dakota, has an electric water heater load-control portfolio that has been running for more than 30 years. It offers two programs, a peak reduction program with 45,000 customers enrolled and a load shifting program that includes 65,000 water heaters. The peak reduction program curtails load for 4–6 hours, 20 to 30 times per year. This reduces total system costs and allows customers to save on demand charges on their electric bills. The load shifting program moves water heating to overnight hours, when electricity prices are lower. Overall, this program has had high customer satisfaction, although both types of load control are more reliable in single-family residential homes than in commercial and multifamily buildings, which have less-consistent hot-water usage patterns. Great River Energy reports the total number of load shed events for each quarter on its website https://lmguide.grenergy.com/ShedCount.aspx.
NEEA	Pacific Northwest	Heat Pump Water Heater (HPWH) Initiative	The Northwest Energy Efficiency Alliance (NEEA) HPWH Initiative promotes efficient HPWH adoption among the 140 utilities and energy efficiency organizations operating under its jurisdiction in Idaho, Montana, Oregon, and Washington. NEEA promotes upstream uptake of HPWH, conducts market research, and connects consumers with rebates and other services offered by their local utilities. Consumer-oriented resources like the Hot Water Solutions webpage address the information barrier for customers seeking to purchase a new HPWH. In addition, NEEA's Advanced Water Heating Specification is driving adoption of efficient HPWH in the region and has influenced the passage of federal HPWH standards.
United Illuminating	ISO-NE	HES-IE (Home Energy Solutions Income Eligible) DERMS program	This program for customers of the Connecticut-based utility United Illuminating began with a pilot in the fall of 2017. It is a direct-install program targeting income-qualified customers who own electric resistance water heaters. Participants receive an upgrade to a high-efficiency heat pump water heater at no cost, with savings of up to 50% of water heating–related energy costs. These HPWHs are demand response capable, and participating customers are signed up to the DR program automatically. Program delivery was temporarily suspended due to impacts from the COVID-19 pandemic but has been resumed along with the utility's other in-home energy efficiency programs.

Sources: NEEA 2021; Podorson 2016; Engle 2019

BUILDING ENVELOPE

Improving a building's overall thermal efficiency is an effective way to curb energy use, particularly during peak seasons. Weatherization improves a home's thermal envelope, reducing air leakage by adding insulation to floors, walls, and attics and installing duct sealing, weather stripping, and other measures that reduce the amount of heat exchanged with the outdoor environment. These improvements reduce the total energy needed to heat and cool the space, thereby improving the performance and extending the life of heating and air-conditioning equipment.

Beyond reducing peak demand, a tighter thermal envelope has many co-benefits such as lower energy costs, better indoor air quality, and improved comfort and health. Weatherization can be especially beneficial for low-income, minority, elderly, and other disadvantaged communities, who are more susceptible to higher energy burdens than the average household (Drehobl, Ross, and Ayala 2020) and also more likely to live in less-efficient homes that would benefit from weatherization (Nadel 2020).[17] Better building envelopes provide greater resilience in the event of winter weather disruptions (e.g., power outages, natural gas shortages) as they allow residents to shelter in place longer before indoor temperatures drop to unsafe levels (Wilson 2005; Cox et al. 2017). This would have been especially beneficial during the February 2021 Texas blackouts as almost 20% of homes in the south-central United States are poorly insulated (EIA 2018).

There may be additional benefits associated with demand response as well, as building shell improvements enable preheating and precooling of space prior to a peak event or system constraint. Improved thermal envelopes may also improve resident comfort during a demand response event.

In addition to weatherizing existing buildings, there are opportunities to lock in long-term energy savings in new buildings through adoption and implementation of stronger building codes. The International Code Council (ICC) publishes model building codes, including energy codes that set efficiency standards for walls, windows, floors, insulation, and all other aspects of the building envelope. Many cities and states base their building codes on the ICC model codes. Some states and utilities have programs specifically targeted toward homebuilders to help them meet or exceed building energy performance requirements. There are also a few programs that promote high-efficiency all-electric new homes. Table 3 lists examples of programs to promote efficient envelopes in existing and new construction.

Table 3. Building envelope program examples

Program administrator	Grid region	Program name	Description
Electric Cooperatives of South Carolina & Advanced Energy	Southeast	Help My House Loan Pilot	Help My House was a pilot program that included 125 customers of electric cooperatives in South Carolina and ran from 2011 to 2013. Participants received whole-home energy audits and tailored measures targeting their specific needs, such as air sealing, attic insulation, and heat pump replacement. These measures produced energy savings as well as peak demand savings, with the average participant home reducing its winter peak demand by 46% relative to pre-weatherization levels.

[17] Energy burden is the share of overall household income spent on energy. Researchers define households that spend 6% or more of total income on energy as energy burdened, and those spending 10% or more are considered severely energy burdened (Drehobl, Ross, and Ayala 2020).

Xcel Energy	MISO	Efficient New Home Construction (MN)/ENERGY STAR New Homes (CO)	Xcel Energy provides incentives to homebuilders seeking to construct new residential units that exceed current building code standards. The program aims to incentivize high-performance buildings that save energy and reduce peak demand. While historically this program has focused on delivering energy and fuel savings, program administrators are now looking for ways to encourage homebuilders to incorporate load management and dispatchable generation into new builds, with an eye to increased grid flexibility during peak events in winter and summer. In 2017 more than 2,000 new homes participated in this program, reducing overall demand by more than 1 MW and saving customers close to 1 GWh of energy.
Commonwealth Edison (Com Ed)	MISO	All-Electric Residential New Construction	ComEd in Illinois offers an all-electric residential new construction program that requires all participating units to meet standards for air tightness and to include ASHP and HPWH heating systems that meet minimum standards for efficiency. Participating homes must also install ENERGY STAR–certified lighting, appliances, and thermostats and are encouraged but not required to provide photovoltaic and battery systems or wiring to support the installation of such systems. Eligible housing types include townhouses, apartment flats, single-family homes, and accessory dwelling units. An incentive of $2,000 is provided per participating home. Demand savings are quantified on the basis of summer peaks only, with more than 7,145 kW of verified savings in 2017.

Sources: Keegan 2013; Xcel Energy Minnesota 2018; Xcel Energy 2021; ComEd 2021; Ampong, Kunkel, and Hitzman 2020

SMART THERMOSTATS

Because space heating is the largest end use that contributes to winter peak demand, reducing or curtailing heating loads can be a powerful demand-side resource. In the residential sector, utilities, aggregators, and their customers control heating through programmable and/or grid-interactive home thermostats, and in the commercial and industrial sectors, they do so with advanced rooftop controls and energy information management systems.

"Smart" home thermostat technologies, such as connected devices offered by Nest, ecobee, and others, are becoming the standard for home and business temperature control. Common smart thermostat features include remote control via a smartphone app, occupancy sensing, and the ability to learn preferences to adjust temperatures when building occupants are asleep or away (ENERGY STAR 2021). Many utilities, including Eversource and National Grid in Massachusetts and Ameren and Commonwealth Edison in Illinois, offer purchase or other incentives to make smart thermostats more accessible to their customers. These devices may be connected digitally to allow remote monitoring, temperature adjustment, and equipment operation by residents and utilities. If these devices are connected to a network and dispatched by a program administrator, their reliability as a demand response resource can be increased (Woolf et al. 2020). Occupancy sensing and temperature setbacks can deliver savings and benefits for commercial and industrial customers as well, as demonstrated by BGE's Small Business Energy Solutions program. Examples of smart thermostat programs are detailed in table 4.

Table 4. Smart thermostat programs

Program administrator	Grid region	Program name	Description
Mountain Parks Electric	SPP	Mysa Thermostat Pilot Program	Colorado-based electric cooperative Mountain Parks Electric piloted a smart thermostat load control program with a specific focus on attaining peak savings in the winter, from October 2019 to April 2020. The thermostats, which cost $104 per unit, were remotely controlled by the utility to set back consumers' electric baseboard heating systems during evening peak hours. Setbacks occurred in approximately 5% of the hours during each month from October to April, and customers reported little to no discomfort relating to load control events. By reducing peak demand through this program, MPE realized between $3 and $11 of savings per device per month of the pilot test period, resulting in an approximate payback period of two years.
Baltimore Gas & Electric (BGE)	PJM	Smart Thermostats for Small Businesses	Baltimore Gas & Electric offers a range of programs for small businesses, including a discount of approximately 70% on the installation of an ecobee3 smart thermostat. This thermostat offers savings of approximately 10% of monthly heating and cooling costs and can be accessed and remotely controlled using a smartphone app.

Sources: Mountain Parks Electric 2021; BGE 2020

LIGHTING

Switching from incandescent to LED lighting has consistently delivered cost-effective kWh savings over the last decade; it also delivers meaningful peak demand reductions. Although much of the low-hanging fruit of lighting efficiency has been claimed in the residential sector, potential savings still remain in the commercial and industrial sectors, particularly for indoor and outdoor LEDs and networked lighting controls (Mellinger and Energy Futures Group 2019). Since there are fewer hours of daylight in the winter than in the summer — particularly at higher latitudes — the use of electric light typically increases during winter peak months. Table 5 highlights examples of programs that are deploying efficient lighting retrofits and controls that offer peak demand savings.

Table 5. Lighting program examples

Program administrator	Grid region	Program name	Description
Metropolitan Area Planning Council (MAPC)	ISO-NE	LED Streetlight Retrofits	This grant program, targeting municipal governments, provides funding to towns and cities in Massachusetts to replace aging street lighting infrastructure with energy-efficient LED lamps. It covers up to 30% of the upfront cost, using funding from RGGI. Since 2013 this program helped more than 30 municipalities replace more than 60,000 streetlamps. Because winter peak hours occur from 4 to 8 p.m., and streetlamps automatically turn on at 4 p.m., efficiency retrofits for street lighting can substantially reduce its impact on winter peak demand.
Massachusetts Program Administrators and Energy Efficiency Advisory Council	ISO-NE	Commercial & Industrial Small Business Initiative: Phase I	This program, focused on commercial and industrial lighting applications throughout several utility service areas in Massachusetts, delivered energy-efficient and controllable lighting measures via rebates and on-bill financing to selected customers. More than 90% of kWh and kW savings through this program were from LED retrofits. Though controllable lighting contributed only 1% of measured kWh savings from this program, evaluators noted the potential for additional savings of 1.5% or more through occupancy sensors alone. In total, the program delivered more than 103,700 MWh and 12.3 MW of winter peak demand savings in Massachusetts in 2016, accounting for 8% of statewide energy efficiency and demand savings for that year.

Sources: MAPC 2021; MA EEAC 2018b

MANAGED EV CHARGING

Achieving widespread decarbonization requires electrifying one of the largest fossil-fueled end uses: transportation. Though EVs are already more efficient than vehicles powered by internal combustion, they are only as clean as the power that they run on. The additional demand that EV charging puts on the electric grid during peak hours may lead power companies to build out additional fossil generation resources.

However, EVs are uniquely flexible loads in terms of when and where their batteries are charged. With proper incentives and messaging, EV owners can provide grid-wide benefits by shifting charge times to off-peak hours. This can be accomplished through either clear pricing signals or "smart" charging devices that can initiate or curtail charging automatically. Both approaches show promising peak-reduction potential in initial studies, described in table 6 below. Managed in this way, EVs can reduce system costs and increase utility revenues in high-penetration states like California (Frost, Whited, and Allison 2019). Planning for an increase in EV load will be an essential aspect of grid management in the coming decades, in particular its impacts on peak demand in the summer and winter.

In the future, EV batteries may provide additional grid flexibility via vehicle-to-grid (V2G) integration. Though this technology exists in demonstration project form, it is not yet commercially available in North America (Khan and Vaidyanathan 2018). One barrier to scaling up V2G is vehicle warranty policies, which largely do not allow EV batteries to discharge for purposes other than powering the vehicle itself. This market barrier is substantial enough that most grid scenario models, such as the U.S. Department of Energy's (DOE) Energy Storage Grand Challenge Roadmap, exclude V2G as a potential energy storage resource within the next 20 years (DOE 2020a). However, as the size of EV fleets increases and battery technology evolves, grid operators may look to utilize the reservoir of power stored within the EV fleet as an additional resource to satisfy demand during peak events.

Table 6. EV program examples

Program administrator	Grid region	Program name	Description
Green Mountain Power (GMP)	ISO-NE	GMP eCharger Pilot	This pilot program provided 273 EV owners with a WiFi-enabled level 2 charger at no cost. Customers who received this charging equipment were enrolled in an EV rate that allowed unlimited off-peak charging for $29.99 per month in the pilot study. In addition, they were enrolled by default in a peak load curtailment program that called events 5 to 10 times per month. Although customers could opt out, fewer than 5% did, and the pilot was able to curtail about 150 kW of capacity during peak events in July 2018, producing a net benefit of $27,000 to utility customers.
San Diego Gas & Electric (SDG&E)	CAISO	Plug-In EV TOU Pricing and Technology Study	This 2014 study by San Diego Gas & Electric sought to quantify the participation and load shifting potential of EVs subscribed to a time-of-use (TOU) rate. The 700 participants in the study were all owners of an all-electric Nissan LEAF with a level 2 (240V) home EV charging system on a separate meter. The study found that EV owners are sensitive to price when it comes to choosing when to charge their EVs, with 87–94% of charging occurring during the "super-off-peak" period between 12 and 5 a.m., when rates are at their lowest. Technology that allowed customers to automatically delay their charge times was also cited by study participants as being influential in their decision to charge off-peak.

Sources: Turk 2020; Cook, Churchwell, and George 2014

CUSTOMER-SITED STORAGE

In a decarbonized grid that is heavily dependent on variable renewable energy sources for power supply, energy storage will be crucial for maintaining reliability. Large-scale energy storage technologies, such as grid-level batteries, pumped hydro, and gravity storage, have emerged in resource planning and procurement, but smaller-scale storage can also support reliability on the customer side, primarily through electrochemical batteries and thermal storage. Home battery systems provide several potential benefits, from providing backup power during an outage to offering peak demand reduction and energy arbitrage services that allow their owners to save money (Fitzgerald et al. 2015).[18] Two pilot programs

[18] Energy arbitrage opportunities will be dependent on the availability of advanced metering and time-differentiated price signals.

evaluating the potential for home battery units to provide winter peak capacity are highlighted below in table 7.

Thermal storage also demonstrates potential to deliver load shedding and shifting benefits, though not as much as battery storage. In the "Water Heating" section, above, we discussed preheating water during off-peak hours as a cost-saving measure. An example of long-term thermal storage using underground boreholes is highlighted in table 7. Although preheating to provide thermal comfort is possible, its energy savings rely on a tight thermal envelope to ensure minimal heat loss. Emerging technologies such as phase-change materials, though not currently widespread in building applications, may eventually become more common by virtue of their ability to store thermal energy at a fixed temperature for extend periods.

Table 7. Storage program examples

Program administrator	Grid region	Program name	Description
Green Mountain Power	ISO-NE	GMP Tesla Powerwall Grid Transformative Innovation Pilot	This pilot program, which began in 2017, subsidized the installation of 2,000 Tesla Powerwall 2.0 units in homes. The purpose of the pilot was to provide participants with reliable backup power in the event of an outage, while also allowing GMP to draw upon battery reserves in times of peak demand. During its first full calendar year of operation (2018), the battery resource was called on several times during monthly peak events, with the maximum reduction of 5,000 kW on January 21, delivering a total value of $53,159 in regional peak mitigation, in addition to participant benefits.
Enel X, L+M Development	NYISO	Marcus Garvey Village Microgrid	The owners of Marcus Garvey Village, a 650-unit affordable multifamily apartment complex in Brooklyn, New York, installed a custom distributed solar + storage energy system specifically aimed at providing reliability and demand response during times of extreme peak demand in the winter due to electric heating. The system includes 400 kW of solar PV, a 400-kW fuel cell, and a 1.2-MWh lithium-Ion battery. Intelligent software on the system automates DER deployment in sync with energy market price signals, providing capacity to Con Edison and NYISO to maximize incentive payments and minimize energy costs to the property owners and building residents. Evaluation results are not available from this project.
Drake Landing Solar Community	AESO	Borehole Thermal Energy Storage	The Drake Landing Solar Community is a demonstration project, completed in 2007, that was the first major implementation in North America of seasonal solar thermal energy storage. Using a borehole thermal energy storage system, hot water from a rooftop solar system was stored in a lattice of subterranean pipes. This heat could be stored for months, meeting more than 90% of space heating needs for the 51 single-family houses in the community.

Sources: Green Mountain Power 2019; Enel X 2019

MULTI-SECTOR PLANS, POLICIES, AND PROGRAMS

A portfolio of diverse offerings enables a program administrator to meet peak demand in a variety of ways, targeting multiple customer sectors and end uses. Programs can be designed to address energy needs holistically through sequencing and integrated design. Table 8 showcases examples from utilities and program administrators that have developed a targeted set of strategies across multiple sectors and technologies.

Table 8. Multi-sector program examples

Program administrator	Grid region	Program name	Description
BC Hydro	British Columbia	Capacity Focused DSM	BC Hydro, a winter-peaking utility, has deployed a range of demand-side measures across multiple sectors and technologies with a goal of creating flexible demand to address capacity constraints. These measures include traditional energy efficiency, direct load control in residential and commercial sectors, and industrial load curtailment, among others. The measures are aimed at capacity-constrained areas, with the goal of alleviating those constraints and addressing other grid-level issues.
Metropolitan Area Planning Council (MAPC)	ISO-NE	Peak Demand Management	This grant program for Massachusetts municipalities and school districts aids participants in understanding, forecasting, and managing their energy use during peak demand hours. Participating groups appoint an energy manager who acts as a liaison between stakeholders such as town administrators, custodians, and facility managers to identify and execute targeted peak demand mitigation strategies, such as thermostat set-point reductions, lighting improvements, and installation of distributed energy resources. Since 2015 participating municipalities and school districts have saved hundreds of thousands of dollars and reduced their peak demand by up to 70%.

Sources: BC Hydro 2013; MAPC 2021

PRICE-INDUCED DEMAND REDUCTION (RATE DESIGN)

Many electricity consumers are unaware that the cost of electricity varies according to time of day and season. By aligning the price per kWh more closely with the cost of delivering energy, utilities can encourage customers to reduce demand during peak hours in both summer and winter months. A meta-analysis by ACEEE found that time-varying rates such as critical peak pricing, time-of-use rates, and peak-time rebates reduced residential peak demand by an average of 16% (Baatz 2017). For customers with large, movable loads, such as industrial users or electric vehicle owners, a time-of-use rate may be attractive because it enables them to reduce energy costs while also lowering their impact on peak demand. For example, electric vehicles have highly movable loads that are well suited to take advantage of time-varying rates, as evidenced by table 6, above. Because there are not many winter-peaking grid regions in North America, there are relatively few winter peak–focused pricing incentives, though this may change as more utilities shift to dual peaking. In table 9, below, we provide one example of a winter-peaking utility offering several incentives and rates that have delivered peak demand mitigation across entire customer sectors through price-induced behavioral change.

Table 9. Pricing program example

Program administrator	Grid region	Program name	Description
Hydro Québec	Québec	Winter Credit Option for Residential & Commercial, Rate DP, Rate DT	Customers on the Winter Credit Option may receive credit equivalent to $0.50 (CAD) per kWh of energy curtailed during winter peak events. Customers on Rate DP (dynamic pricing) receive a decreased kWh rate during shoulder months and an increased demand charge during summer and winter peak events. And Rate DT (dual energy) is designed specifically for residential customers with dual-fuel heating systems to encourage switching to fossil-fueled heat during winter peak events. Depending on the outdoor temperature, customers receive a signal to reduce their use of electricity in winter. Rate DT customers enjoy a lower kWh rate throughout the rest of the year, including the summer. There are no evaluations available detailing the system peak demand benefits of these rates.

Source: Hydro-Québec 2021

The programs, policies, and initiatives discussed in this chapter represent a range of approaches taken by utilities and program administrators that can deliver winter peak demand reduction and other benefits such as lowered costs for consumers and increased productivity, safety, and comfort. Though a wide variety of technologies exist, their adoption is limited in scale and scope and is seldom aimed specifically at reducing winter peak demand. Many of the pilots highlighted here serve just a small percentage of utility customers. Even programs like weatherization, which uses reliable technologies and techniques and provides a long-term solution for energy affordability and peak demand reduction, are underfunded at the federal and state levels. This lack of investment means that only 2% of low-income households receive weatherization services every year (Drehobl 2020). More advanced "smart" technologies, such as cold-climate heat pumps and DR-capable thermostats, demonstrate clear potential but likewise reach a smaller fraction of customers than is needed to deliver massive energy savings and load flexibility.

To accelerate change in a transforming market and prepare for a highly electrified future with winter peaks, utilities and program administrators should focus on scaling up pilots and programs, particularly those that can deliver targeted savings during peak events. Investing now to drive early adoption and develop a workforce that is well versed in installing high-efficiency measures will lead to lower costs in the future. However, if utilities delay efforts to scale up DSM programs now, then the cost to mitigate peak demand through demand-side measures may be much higher in a future with extreme winter peaks. In regions like New England, which both has aggressive GHG reduction goals and is forecast to transition to winter peaking over the next decade, leading utilities are demonstrating multiple programs and technologies to respond to a changing grid. The adoption and impact of demand-side measures will likely change dramatically over the coming decades, as demonstrated in the following regional analysis.

Regional Analysis — New England

The goal of this section was to model the impact of demand-side measures on a winter peak event in New England in 2040. To do so, we developed a load profile for an extreme New England winter weather event that extends over multiple days and corresponds to a regional winter peak. We then examined the impacts of three packages of demand-side measures.

New England was a winter-peaking region until 1989 and a dual-peaking region from then until about 1993. It has been summer peaking ever since — a transition caused by a growing use of air conditioners and declining use of electric heating. Since 2000, the hottest summer and coldest winter days in New England have led to average peaks of 25,600 MW and 21,000 MW, respectively (ISO New England 2020d). However, the region is poised to become winter peaking again in the 2035–2040 time frame (Mettetal et al. 2020; Nadel 2016). The exact year depends on a variety of factors including the rate of end-use electrification, efficiency gains, and deployment of renewable energy resources.

We find New England — or more specifically ISO-NE — to be an interesting target of study for several reasons. The region has some of the United States' most ambitious climate goals, with all six states having economy-wide GHG emission reduction targets of at least 80% by 2050. This will act as a key driver of the conversion from fossil-based sources of heating like natural gas and oil to low-carbon sources like electric heat pumps powered by renewable energy.[19] The New England region also possesses relatively good and publicly available data about end-use load profiles and avoided costs that are key to this analysis.

Organizations like Synapse Energy Economics, ISO-NE, and NREL have developed projections for the number of newly electrified end uses (e.g., space heating and EVs) that will be in use in future years. From these sources we adopted a high electrification scenario and a lower electrification scenario (defined below) that we use in our regional analysis. The high scenario closely aligns with the region's state climate goals and provides the more challenging situation for DSMs to address.

Our analysis followed several steps. First, we selected an historic, four-day New England weather event that generated a winter peak, and from that we calculated a regional hourly heating demand. We converted this heating demand to an hourly electric heating load under two future electrification scenarios. We added to the space heating load the load profiles of other relevant end uses to produce a partial system load profile for ISO-NE in 2040. We then applied three packages of DSMs to each of our modeled scenarios to ascertain how different combinations of efficiency and flexibility measures affect system peak.

[19] Research indicates that deep decarbonization of New England to a level demanded by states' climate goals requires a 210% increase in electrification of end uses and a 40% decrease in energy use per capita (Williams et al. 2018).

We note that these results are specific to ISO-NE. They should not be used to draw explicit conclusions about the efficacy of DSMs in other regions of the country where factors like climate, end-use distribution, and vehicle miles traveled may be substantially different. However, we expect that our broad conclusions, including which DSMs are most effective at reducing system peak, and over what time frames, will be informative and supportive of more detailed analysis of the rest of the country.

CREATING THE WEATHER EVENT

We modeled our extreme winter weather event after a real polar vortex storm that moved from the upper Midwest through New England between January 30 and February 2, 2019 (Hopkins, Takahashi, and Nadel 2020). We selected a single city—Worcester, Massachusetts—to represent the temperature across the region, as shown in figure 3. Worcester was chosen because it is proximate to New England's major population centers (more than three-quarters of New England residents live in Massachusetts, Connecticut, and Rhode Island), but lies outside the densest urban environments on the coast, where temperatures can be systematically higher.

While it would be preferable to analyze local temperatures for each section of New England, the Residential Energy Consumption Survey (RECS)—from which we extract our building characteristics—provides data only at the census division level, inhibiting higher-resolution analysis.

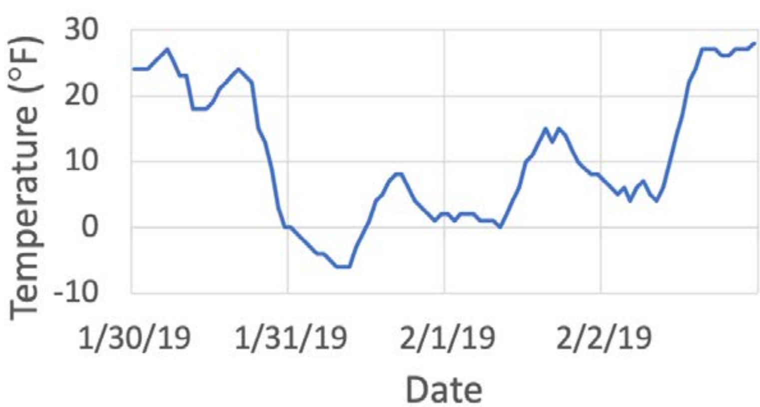

Figure 3. Modeled temperatures for our extreme winter weather event. The temperature profile is identical to that measured at the Worcester Regional Airport Station during the 2019 polar vortex event.

ELECTRIFICATION SCENARIOS

We used our selected outdoor temperature profile and assumptions about the saturation and performance of behind-the-meter loads to construct two hypothetical electrification scenarios (i.e., system load profiles) for ISO-NE in 2040. We defined a *scenario* by the number of electrified end uses deployed in buildings at a given point in time. Our two scenarios differed only in the number of residential ccASHPs assumed to be in operation.

While these profiles were constructed from a variety of sources, we drew most heavily from two in particular: NREL's Electrification Futures Study (EFS) and Synapse's New England

Electrification Load Forecast (Mai et al. 2018; Goldberg et al. 2020). The former is a national market-based model; the latter is a policy-based model through 2029 focused on what is needed to meet New England's ambitious climate targets. These sources were supplemented, where appropriate, with contemporary results. We used EIA's *Residential Energy Consumption Survey* (RECS) and *Commercial Building Energy Consumption Survey* (CBECS) to infer the thermal envelope properties of a representative sample of the New England building stock (EIA 2016, 2018). We used the EPRI Load Shape Library to obtain approximate shapes for major building loads in the residential and commercial sectors (EPRI 2020). The EPRI shapes do not cover all residential loads, so to fill in the gaps we used data from a 2018 Navigant baseline study that collected detailed, metered end-use data in Massachusetts homes between May 2017 and April 2018 (Navigant Consulting 2018). Projections of end-use consumption (other than heating and EVs) in 2040 were pulled from EIA's *Annual Energy Outlook* (EIA 2020a). Further details on the provenance of our electrification scenarios are provided in Appendix A.

Loads and Sectors

In this section we summarize the end uses that made it into our 2040 ISO-NE system load profile. This includes descriptions of the technologies and the manner in which their distributions and performance were forecast. We refer the reader to Appendix A for more details on these end uses and the parameterization of our electrification scenarios.

New Buildings

To account for new residential load in 2040, we used a combination of regional and national projections. On the basis of state planning projections, we assumed that the population of the six New England states will increase 4.86% from 2015 to 2040.[20] The total amount of housing scales approximately one to one with population (Bettencourt et al. 2007). Therefore, we likewise assumed that the number of residential buildings in New England will increase 4.86% between 2015 and 2040 to a projected total of 5,902,406. While the forecasts and electrification studies we drew from account for load growth from new buildings, we used this estimate to account for DSMs that impact existing and new construction differently in residential buildings. We made no similar distinction for commercial buildings.

Space Heating

A building's space heating loads are dependent on the installed heating technology, the quality of the building envelope, and occupant behavior. Using RECS, we calculated a proxy statistic that captures all three for New England buildings, and which is measured in Btus per hour per heating degree day (HDD).[21] Changes in heating technology and envelope

[20] Projections are drawn directly from state estimates where available (Massachusetts DOT 2019; Connecticut State Data Center 2017; Rhode Island Statewide Planning Program 2013; New Hampshire Office of Energy and Planning 2016; University of Virginia Weldon Cooper Center for Public Service 2018).

[21] A heating degree day is the difference (in degrees) between a day's average temperature and 65°F. A larger number of HDDs indicates greater demand for space heating.

properties are interpreted as changes in this statistic and are translated into new electric loads accordingly.

Figure 4 compares the Synapse ccASHP deployment projections alongside the EFS high-electrification scenario. The range of projections reflects the uncertainty surrounding the amount of novel technology adoption decades into the future. In our judgment, both the EFS and Synapse projections have merit. The former is driven by technology and market uptake considerations, while the latter are based on regional climate policy requirements.

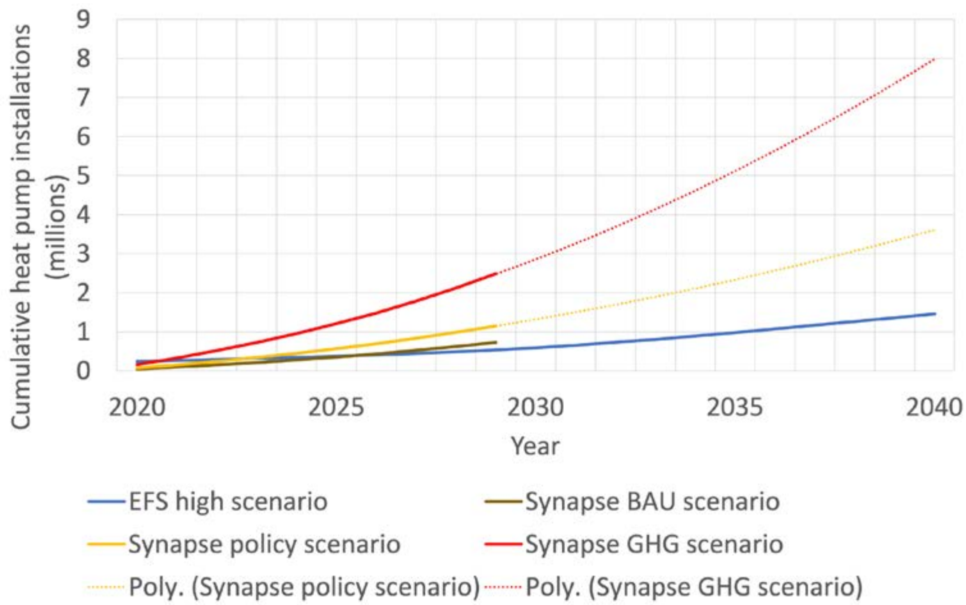

Figure 4. Assumed ccASHP adoption in New England. BAU = business as usual. "Poly." refers to second-order polynomial extrapolation.

To be responsive to both potential futures, we considered two space heating electrification scenarios for 2040. The first assumes a deployment of approximately 1.46 million residential ccASHPs as reflected in the EFS high scenario. The second, an extrapolation of the Synapse GHG scenario projection, is a limiting case that assumes New England meets 100% of its residential space heating demand through ccASHPs. Both of these adopt the EFS scenario that 8.2% of commercial heating capacity will be met by ccASHPs, 28.1% will be met by electric boilers, and the remainder will be met by fossil fuels (Mai et al. 2018).[22]

We used the Northeast Energy Efficiency Partnerships' (NEEP) cold-climate air source heat pump list to calibrate our heat pumps' performance in 2040. This performance varies as a function of temperature, so we leveraged research currently in progress at ACEEE to estimate the coefficient of performance as a function of outdoor temperature $\mathrm{COP}(T)$ for

[22] In New England, electricity is 5 to 11 times more expensive than natural gas per Btu generated, which poses a steep challenge to the growth of electric commercial boilers reported by the EFS high scenario. We adopted this scenario for consistency, but note that this large a number of boilers may lead to an overestimate of the electric space heating load in the commercial sector (Rightor, Whitlock, and Elliott 2020).

both residential and commercial heat pump units. We assumed that when the temperature drops below a certain threshold, the units switch to either an electric resistance or fossil backup heating mode. We also considered ground-source heat pumps (GSHP) as one of our DSMs and assumed they have a constant COP of 4.26. While other electrified heating sources like water-source heat pumps and district heating systems may play a role, none were reported as being significant in the sources from which we derived our electrification scenarios.

Our base case electrification scenarios assumed no improvements to the thermal envelope (via weatherization or deep energy retrofits) for existing buildings by 2040. We estimated the relative envelope performance of new residential construction using the properties reported by RECS for New England buildings constructed between 2000 and 2015.

ELECTRIC VEHICLES

We assumed that in 2040 there will be about 3.02 million all-electric vehicles in New England. As with heat pumps, the EFS and Synapse scenarios for EVs do not match up. We found that the Synapse GHG scenario projection most closely matches the EFS medium scenario in 2029, and the second-order polynomial extrapolation of the Synapse policy scenario most closely matches the EFS medium scenario in 2040 (see figure 5). As a compromise, we used the EFS medium scenario for our EV estimate. We further estimated that the combination of light-, medium-, and heavy-duty EVs will draw an average of 9.15 kWh per day per vehicle.[23]

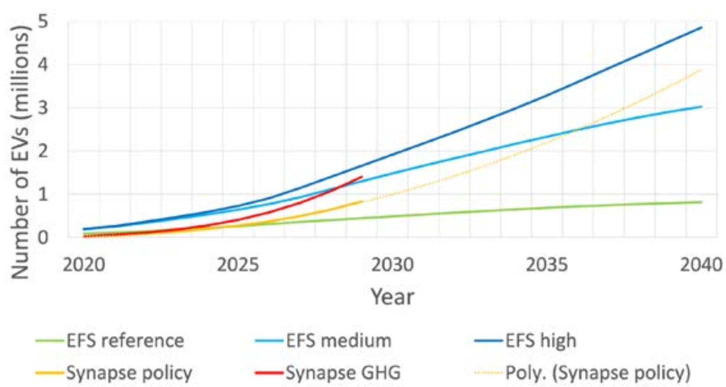

Figure 5. Synapse and EFS EV stock scenarios

WATER HEATING

Water heating was modeled separately for electric resistance and heat pump water heaters (HPWHs). The residential and commercial electric resistance water heater load shapes were drawn from the EPRI Load Shape Library (EPRI 2020). The load shape of residential HPWHs was drawn from a Navigant study, but we note that this study was based on only

[23] Today's electric vehicle stock contains both all-electric battery-powered vehicles (BEVs) and plug-in hybrid vehicles (PHEVs) that operate on electric power part of the time, then transition to an internal combustion engine when needed. While the grid impacts of charging BEVs and PHEVs differ, modeling from the Transportation and Climate Initiative projects that 94% of new EV purchases will be BEV by 2030 (Transportation and Climate Initiative 2019). We approximate by extension that all EVs in New England will be all-electric by 2040.

28 Massachusetts homes and therefore contains relatively large uncertainty (Navigant Consulting 2018). We were unable to identify a reliable commercial HPWH load shape, and instead assumed they possess the same load shape as commercial electric resistance models. Load shapes were normalized using the EFS high electrification scenario, which reports approximately a 7% increase in water heating equipment stock.

OTHER LOADS

In addition to the loads already mentioned, we generated estimated 2040 load shapes for residential lighting, indoor and outdoor commercial lighting, residential clothes washers and dryers, residential kitchens, commercial ventilation, and residential "other" in a manner similar to how we developed the loads described above. However, we project that none of these loads will be significant contributors to winter peaking in a way that could be directly addressed through a set of future DSMs.[24] We elected not to model commercial "other" loads, as we were unable to identify a reliable projected load profile for this group of end uses.

We also opted to not model the industrial sector. Industrial system load driven by energy-intensive process manufacturing tends to operate around the clock, seven days a week, and is not particularly sensitive to weather, especially compared with the residential and commercial sectors (EIA 2021a). The bespoke demand response offerings that utilities often develop for industry are beyond the scope of this report.

There is also significant uncertainty regarding future electrification scenarios for the industrial sector. Many industrial processes, like process heating, are extremely challenging to electrify and will likely require yet undeveloped technologies that may or may not directly interface with the electric grid (Cunliff 2019). Estimating how efficiency and demand flexibility could be optimized to shape, shift, or shed those loads during a future winter peak is therefore extremely speculative.

Weather Event Load Profiles

The projected load profiles for our two electrification scenarios during an extreme four-day weather event in New England in 2040 are presented in figures 6 and 7. Figure 6 depicts the EFS scenario in which there are 1.46 million residential heat pumps installed. Figure 7 shows the limiting case where 100% of residential heating demand is met by ccASHPs. Note that these load profiles omit industrial loads and any commercial loads that fall outside the categories of lighting, ventilation, space heating, or water heating.

The leading driver of peak demand in both electrification scenarios is residential space heating, followed by commercial space heating.[25] All other loads are modeled independent of temperature and electrification scenario and maintain a constant daily load profile. Those

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[24] While residential "other" loads, many of which fall into the miscellaneous electric loads (MELs) category, are significant in size, demand-side measures to address this motley assortment of end uses are limited.

[25] These profiles reflect buildings' space heating demand per heating degree day as measured over the course of a year. They do not account for hourly temperature set-point adjustments (e.g., turning down the thermostat before going to sleep or after a business has shut down for the day). As a result, space heating loads during daytime and nighttime hours are likely to be somewhat underestimated and overestimated, respectively.

loads, in descending order of daily energy draw, are residential (other), commercial lighting, residential lighting, residential water heating, commercial ventilation, and EVs.

We observe in the EFS scenario that a lower penetration of electric heating results in a load profile that more closely resembles the contemporary winter dual-peaking profile (e.g., see figure 1). As the percentage of residential heat pumps increases to 100%, the load profile exhibits higher-magnitude spikes, especially when the exterior temperature drops the heat pumps near or into electric resistance mode. We observe that the height of the winter peaks differs considerably between our two electrification scenarios. Increasing the number of residential heat pumps from 1.46 million to 5.90 million increases peak load by about 34 GW during the winter peak.

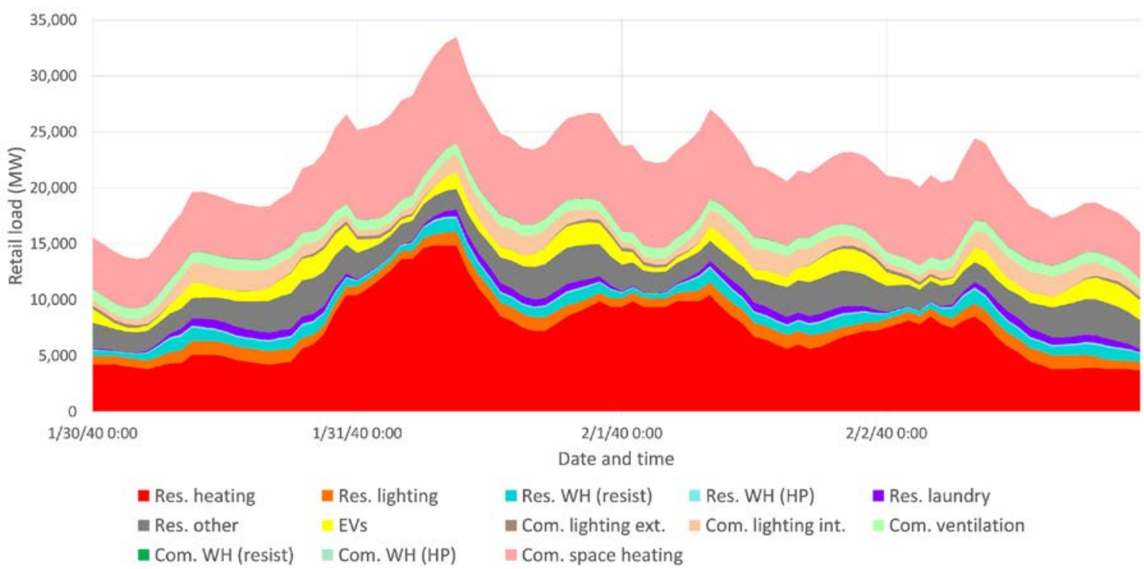

Figure 6. New England load profile during 2040 polar vortex event; EFS scenario with 1.46 million ccASHPs with electric resistance backup; no industrial loads or commercial "other" loads

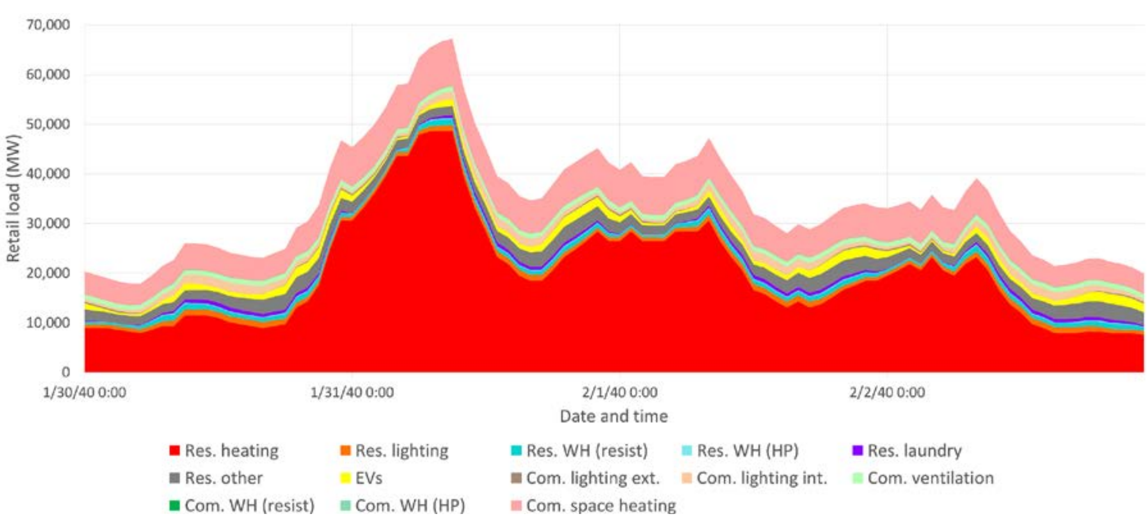

Figure 7. New England load profile during 2040 polar vortex event; 100% residential ccASHPs with electric resistance backup; no industrial loads or commercial "other" loads

DSM PACKAGES

With the 2040 New England electrification scenarios outlined above, we constructed three DSM packages to apply to our estimated 2040 load profiles: *standard*, *smart*, and *deep*. These packages were developed as a way to explore the benefits of varying degrees of DSM rollouts targeting winter peaks. The standard package represents what we expect 2040 to look like if current best-in-class utility EE portfolios — such as those in Massachusetts, Rhode Island, and Vermont—are deployed around the region.[26] The smart package adopts all the efficiency measures in the standard package and adds further benefits of connectivity, intelligence, and load flexibility. The results of this package reflect a future in which grid-interactive building (GEB) technologies achieve greater market saturation and utilities are able to use them as a grid resource. The deep package takes DSMs to the next level, enabling greater energy savings and more effective flexibility. This package represents a plausible but ambitious set of measures and technology improvements designed to meet New England's deep decarbonization goals.

The following section describes in some detail the DSMs that populate our three packages and how we derived them; table 10 summarizes the packages and their component parts.

Demand-Side Measures

We considered the following demand-side measures to reduce winter peaks within three categories. *Energy efficiency* refers to the permanent reduction of load through improved technology, controls, or engineering; *load shifting* is the short-term movement of load from times of high demand to times of low demand; and *load shedding* describes the curtailment of load to provide peak capacity support.

We allow for behind-the-meter resources to contribute to demand flexibility. These include all forms of thermal and electrochemical battery storage (including EVs) and any temporary shedding or shifting of heating, lighting, or appliance loads. For this analysis we do not place constraints on the means by which this flexibility is realized (e.g., switches, voluntary measures, time-of-use rates, incentives).

<u>Energy Efficiency</u>

- Improved performance of ccASHPs
- Weatherization
- Residential smart thermostats
- Commercial energy information management systems and advanced rooftop controls
- Installation of geothermal heat pumps

<u>Load Shifting</u>

- Dispatch of behind-the-meter electrochemical batteries
- Managed EV charging

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26 These states are the top three scorers for utility and public benefits programs and policies in the ACEEE *2020 State Energy Efficiency Scorecard* (Berg et al. 2020).

- Water heating demand response

Load Shedding

- Temperature set-point reductions

A number of other DSMs were considered for this analysis.[27] However, we decided to focus on the measures we believe can have the greatest impact on reducing winter peaks specifically in 2040 under our electrification scenarios. Consequently, this list of DSMs preferentially addresses space heating demand. Details regarding how these DSMs were calibrated can be found in Appendix B.

IMPROVED PERFORMANCE OF CCASHPS

For our DSM packages, we assumed ccASHP performance that has been demonstrated to be technically feasible today and that could conceivably come to represent average performance within 20 years under different pathways of technology adoption. We used NEEP's cold-climate air source heat pump list to identify the COP at maximum capacity at 5 °F for more than 8,300 heat pumps. We ordered those heat pumps by their coefficients of performance and selected the COPs of those at the 25th, 50th, and 75th percentiles to represent the base electrification scenario, standard/smart package, and deep package. These turn out to 1.88, 2.05, and 2.25, respectively (NEEP 2020). We maintained the $\mathrm{COP}(T)$ relationship from Nadel and Perry (2020) and shifted the curves vertically to parameterize. Those relationships are pictured for the residential and commercial cases in figures 8 and 9, respectively.

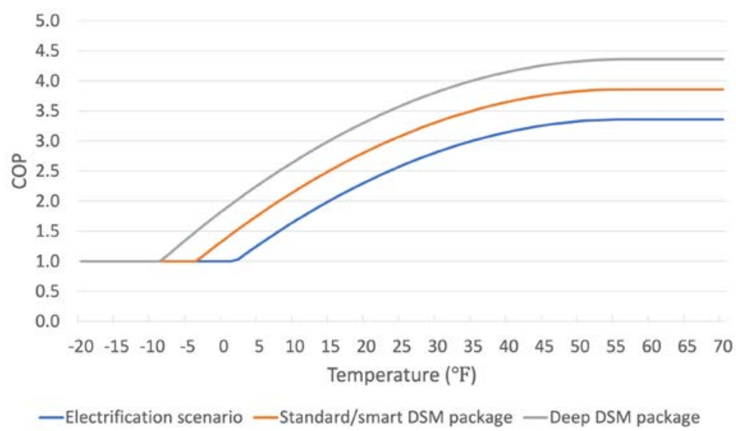

Figure 8. Assumed performance of residential ccASHPs within our electrification scenarios and DSM packages

[27] Additional measures considered included building preheating, electric thermal storage, staging of HVAC equipment, advanced thermal energy recovery systems, dynamic dimming and spectral energy reduction of lighting, conservation voltage reduction, delayed running of appliances, and reductions of other, miscellaneous loads.

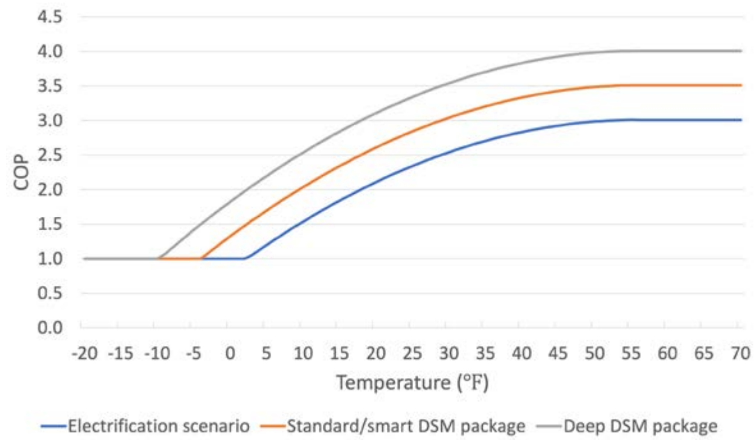

Figure 9. Assumed performance of commercial ccASHPs within our electrification scenarios and DSM packages

WEATHERIZATION AND THERMAL ENVELOPE RETROFITS

Our envelope DSM packages involve two factors: the fraction of buildings upgraded, and the average energy savings per upgrade. We calibrated our levels of energy savings largely on the basis of comparisons of building characteristics described in various editions of the International Energy Conservation Code (IECC) and ASHRAE 90.1. We assumed that weatherization brings a home's thermal performance from a 2006 baseline to IECC 2015 and a commercial building's performance from an ASHRAE 2007 baseline to the 2019 standard. These improvements are good enough for a 20–25% reduction in building heating consumption.[28]

We introduced deep building retrofits under our deep DSM package. Such retrofits involve more comprehensive alterations to improve building envelope performance above and beyond standard insulation and air sealing measures (Less and Walker 2014). We estimated an average space heating savings of 50% for deeply retrofit buildings. This aligns with a DOE and NREL analysis of deep retrofits in cold-climate homes in Massachusetts and Rhode Island that found that comprehensive envelope upgrades led to a 41% improvement relative to IECC 2015 standards and a 58% improvement relative to IECC 2006 (Osser, Neuhauser, and Ueno 2012).

We estimated that 24.1% of homes and 22.6% of commercial buildings will be weatherized under our standard and smart DSM packages. We based these estimates on participation levels in recent whole-home retrofit programs run by Eversource and National Grid. Their residential programs reach about 1.2% of eligible homes per year, which we linearly extrapolated to 24.1% of homes 20 years later. Similarly, commercial building retrofit programs reach 1.1% of eligible commercial customers per year, for a total of 22.6% by 2040. We doubled both percentages of buildings reached through weatherization in our deep

[28] The 2006 IECC codes were used as a baseline to represent a central point among older homes (pre-1950), which represent 27% of the total building stock in New England; homes that have already received some degree of weatherization and retrofit measures; and newer homes that have been constructed with tighter building envelopes (NREL 2021b).

package. Deep energy retrofits are considerably more difficult to achieve at scale, so we applied this demand-side measure in our deep package to only an additional 10% of buildings.

Our standard DSM package assumes new buildings are constructed to IECC 2021 codes, leading to a (conservative) decrease of 10% in space heating load (NBI 2020). In the deep package, we assumed new residential envelopes are built to passive house standards, leading to a drop of 75% in space heating load (Passipedia 2020).

RESIDENTIAL SMART THERMOSTATS

For the deployment of smart thermostats, we extrapolated the current 2% adoption rate of residential smart thermostats in New England to assume 50% in our smart DSM package. The projected space heating energy reduction is 6%. In the deep DSM package, we further optimized homes with the integration of home energy management systems, increasing thermal savings to 14% in 80% of existing buildings and in 100% of new construction (NEEP 2019).

INTELLIGENT LOAD CONTROL — COMMERCIAL

Concerning intelligent thermal management, we distinguished between small/medium commercial (SMC) buildings (i.e., less than 100,000 square feet) and larger commercial buildings. In our deep DSM package, we introduced a combination of energy information management systems, advanced rooftop controls for HVAC, and installation of submeters to SMC buildings. These systems have the potential to cut HVAC energy use by 20–40%, so we adopted an average savings of 30%. Large commercial buildings traditionally use large, built-up systems with boilers, chillers, and cooling towers. These building systems are unable to achieve the same levels of savings as SMC buildings, reducing the potential for additional savings through advanced controls to 18% (Perry 2017).

Approximately 54% of commercial buildings' floor area comes under the control of a building automation system. This includes 73% of commercial health-care buildings' floor area, a number we believe is representative of complex large buildings (Perry 2017). New building codes are starting to require control systems for large building systems, which we estimated will lead to 80–90% penetration in large buildings by 2040 (C. Perry, buildings research manager, ACEEE, pers. comm., November 11, 2020). This leaves approximately 30% of commercial buildings with the opportunity to benefit from intelligent thermal management.[29]

GROUND-SOURCE HEAT PUMPS

As of 2017, there were 35 financial incentives for GSHP installations in place in New England, commonly in the form of rebates or loans (McCray 2017). However, statistics on the uptake of those programs are more difficult to locate. The Massachusetts Clean Energy Center (MA CEC) reports that between January 2015 and July 2019 there were 379 GSHPs

[29] The deep DSM package assumes that the leading commercial building sector — health care — will increase its penetration of building automation systems (BAS) by about 10% in the next 20 years. We assumed that the other commercial sectors, whose average BAS penetration is currently about 50%, will catch up, leading to our estimate of an additional 30% of commercial floor area being thermally managed in this way by 2040.

installed in Massachusetts with an average COP of 4.26. Homes installing GSHPs had an average floor area of 3,547 square feet (Massachusetts Clean Energy Center 2019).

The total square footage of residential homes is New England is about 12.3 billion (EIA 2018). Massachusetts contains about 46.4% of the population of New England, so we estimated that 46.4% of the residential square footage of New England is in Massachusetts. This comes to 5.7 billion square feet. This suggests that over roughly a 3.6-year period, MA CEC got ground-source heat pumps into about 0.023% of existing floor area, or 0.0064% per year. Extending this to 2040, that means we can expect about 20 times this number, or 0.13%, for the standard package. For the deep case, we model an annual ground-source heat pump program growth rate of 10%, which amounts to a total deployment factor increase of 6.7, or 0.87%.

LOAD SHIFTING — ELECTROCHEMICAL BATTERIES

Behind-the-meter storage can take multiple forms, including dedicated electrochemical batteries (e.g., Powerwalls), EV batteries, and thermal storage.[30] To the best of our knowledge, there are very few, if any, projections of behind-the-meter storage deployments by 2040, let alone projections with regional resolution.

Therefore, we combined an estimated ratio of storage capacity to solar PV capacity with an extrapolated ISO-NE forecast of behind-the-meter solar PV to estimate that there will be about 1,650 MW of non-EV battery storage installed in buildings by 2040 (ISO New England 2020b). We used projections of the percentage of utility customers who will be enrolled in time-varying rates (36% in 2040) as a proxy for the percentage of that battery capacity that will be available to participate in a peak DR event (Hledik et al. 2019). Using data from an ongoing battery DR pilot being run by National Grid, we projected that 50% and 72% of that participating battery capacity will be available for charge and discharge in our smart and deep DSM packages, accounting for 297 MW and 594 MW of flexible battery capacity, respectively (National Grid and Unitil 2020). We imposed a constraint that discharged batteries must be fully recharged within 12 hours, though in practice our DSM packages were almost always able to restore charge on much shorter time scales.

LOAD SHIFTING — EV BATTERIES

This DSM enables the shift of EV charging from peak hours to the off-peak hours of 12 to 6 a.m. An SDG&E pilot program found that on average, EV owners on a time-of-use (TOU) plan charged at home 95% of the time, with 83% of that charging taking place during off-peak hours. This led to an average load shift of 78.8% relative to non-TOU EV charging. For both our smart and deep DSM packages, we assumed that participating EVs will shift up to 80% of their daily charging demand to no later than 6 a.m. (Cook, Churchwell, and George 2014).[31]

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[30] U.S. national labs are currently developing advanced thermal storage technologies including phase-change materials, but we estimate those advancements—many of which are envelope related—will be relegated to a subset of new construction and will not play a critical role in reducing winter peaks in 2040. We recognize that commercial-scaled thermal storage (e.g., ice or chilled water storage) and preheating of buildings with tight thermal envelopes could play valuable roles as DSMs, but neither are considered in this analysis.

[31] We considered the possibility of using vehicle-to-grid (V2G) as a DSM, but there is little available data about the feasibility of EVs discharging their batteries to the grid. The impact on system load would be to increase the

WATER HEATING DEMAND RESPONSE

In the past few years, grid-connected water heating programs have been introduced in many U.S. states. While grid-connected water heaters can provide multiple grid benefits, this demand-side measure focuses on their peak-shaving capability enabled by delayed water heating (Hledik, Chang, and Lueken 2016). This measure can be executed for any connected water heater (with either built-in or retrofit control). We assumed load can be curtailed for a maximum of four hours, with service fully restored after the DR event. Where currently employed, this often occurs with no impact to the customer. We assumed for our smart DSM package that 44% of water heaters participate in this DR program. This is an illustrative number based loosely on historical residential DR program enrollment data (Hledik, Chang, and Lueken 2016). For our deep DSM package, we assumed aggressive utility efforts to install controls or incentivize connected water heaters, increasing the participation rate to 80%.

TEMPERATURE SET-POINT REDUCTIONS

We modeled this load shedding DSM on a request by Xcel Minnesota that its customers voluntarily reduce their temperature set points by 2 °F during the 2019 polar vortex on which our simulated weather event is based (Xcel Energy 2019). While we were unable to locate data on the number of customers who participated, we anticipated that the percentage will increase as homes install more smart thermostats and gain greater grid interactivity, and as utilities develop formal programs to execute the reductions.

Table 10. Demand-side measure packages

DSM	Standard	Smart	Deep
Improved performance of ccASHPs	COP of ccASHP at maximum capacity @ 5 °F increases from 1.88 to 2.05.	Same as standard	COP of ccASHP at maximum capacity @ 5°F increases from 1.88 to 2.25.
Improvements in thermal envelope — existing buildings	Envelope upgrades are completed in 24.1% of residential homes and 22.6% of commercial buildings, leading to an average per-building space heating savings of 22.5%.	Same as standard	Retrofit participation rates are doubled over the standard case. An additional 10% of existing residential and commercial buildings are reached by deep retrofits, leading to an average per-building space heating savings of 50%.

magnitude of standard EV load shifting. Such an approach would also bring challenges like potentially voiding a battery warranty if issues related to its charging and discharging in this manner are not resolved.

Improvements in thermal envelope — new construction	All new residential buildings are constructed to IECC 2021 standards, with corresponding decrease of 10% in space heating load density relative to electrification baseline.	Same as standard	All new residential buildings are constructed to passive house standards, with corresponding decrease of 75% in space heating load density relative to electrification baseline.
Residential smart thermostats	N/A	Space conditioning is optimized for 60% of all residential buildings through the use of smart thermostats, delivering expected energy reductions of 6% and 7% for heating and cooling, respectively.	Space conditioning is optimized through the adoption of integrated home energy management systems, increasing thermal savings to 14% in 80% of existing buildings and 100% of new construction.
Intelligent thermal control (commercial)	N/A	N/A	Installation of submeters, energy information management systems, and advanced rooftop controls (ARCs) cut HVAC-related energy use by 30% in 30% of small and medium-size commercial buildings. Similar energy use is reduced by 18% in 30% of large commercial buildings (Perry 2017).
Ground-source heat pumps	0.13% residential electric heating systems (ccASHPs for 100% HP scenario and electric resistance for EFS scenario), and 0.13% of commercial electric boiler loads, are converted to ground-source heat pumps with fixed COP of 4.26.	Same as standard	Same as the standard case, except we assume ground-source heat pump program growth of 5% per year over 20 years, increasing penetration from 0.13% to 0.34%.
Space-conditioning load shedding	N/A	GEB devices enable an average temperature set-point reduction in 10% of buildings from 65°F to 63°F.	Same as the smart case, except 50% of buildings execute set-point reductions.

Electrochemical battery storage	N/A	36% of behind-the-meter electrochemical batteries (not including EVs) participate in programs that discharge 50% of their maximum capacity to alleviate peak demand. Battery storage is completely recharged within 12 hours of the DR event.	Same as the smart case, except the percentage of participating battery capacity and the average discharge increase to 50% and 72% of maximum capacity, respectively.
Connected hot-water heaters	N/A	44% of electric water heaters participate in demand response events in which water heating load is fully curtailed for 2–4 hours, shifting that load to either the hours immediately preceding or following the DR event, as needed.	Same as smart case, except 80% of electric water heaters participate.
Managed EV charging	N/A	25% of EVs participate in a program that shifts 80% of each hour's load to off-peak hours.	75% of EVs participate in a program that shifts 80% of their daily charging to off-peak hours.

Results — EFS Electrification Scenario

In this section we discuss the results of applying our three DSM packages to our EFS electrification scenario in which 1.46 million residential heat pumps are deployed in New England in 2040.

Over the course of our simulated four-day polar vortex event, the standard DSM package—which could realistically result from an extension of current New England demand-side measure programs—reduces total energy consumption by 1,160 GWh and shaves peak load by 6.7%, equivalent to the output of approximately 10 peaker plants.[32] There are some load savings at all hours, with more during morning peaks, as shown in figure 10.

[32] The actual percentage of shaved peak will be lower than that reported here, due to the exclusion of industrial and other commercial loads from this load profile.

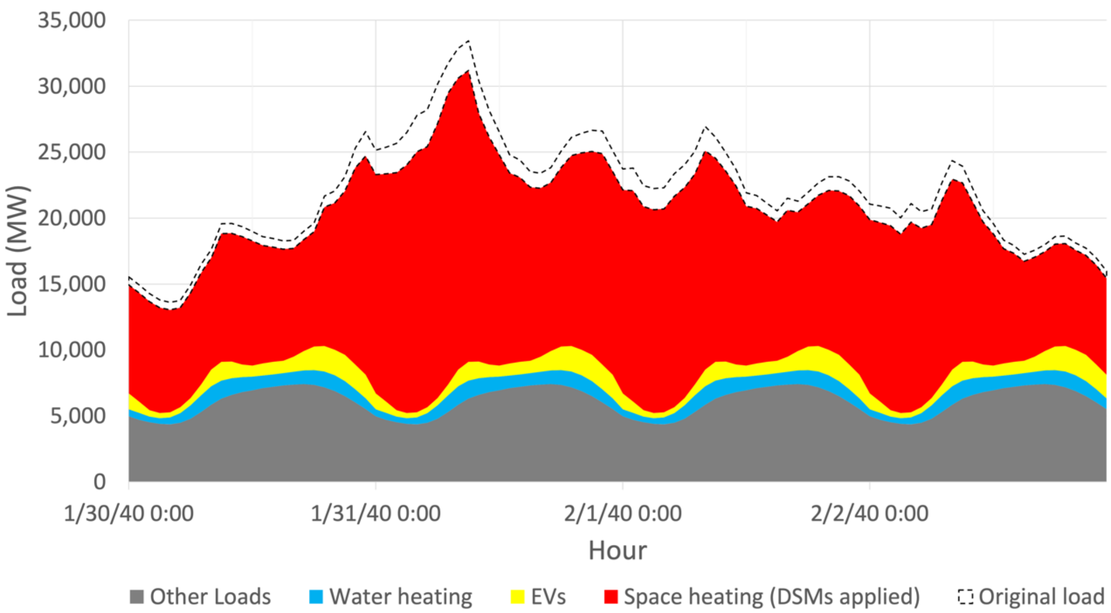

Figure 10. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (electric resistance backup) before and after applying standard DSM package. Industrial and "other" commercial loads not included.

With standard DSM programs, we find the most savings at peak from the improved performance of ccASHPs, as shown in figure 11. We note a dip in this measure's load savings during the morning of January 31 when the outside air temperature approaches the ccASHPs' changeover temperature. This highlights the importance of HVAC system performance when those systems begin to be deployed at scale. The next most impactful measure is residential weatherization, which rises in importance as load is electrified. Commercial measures, though significant, are less impactful as our electrification scenario assumes about 70% of commercial heating remains powered by fossil fuels in 2040.

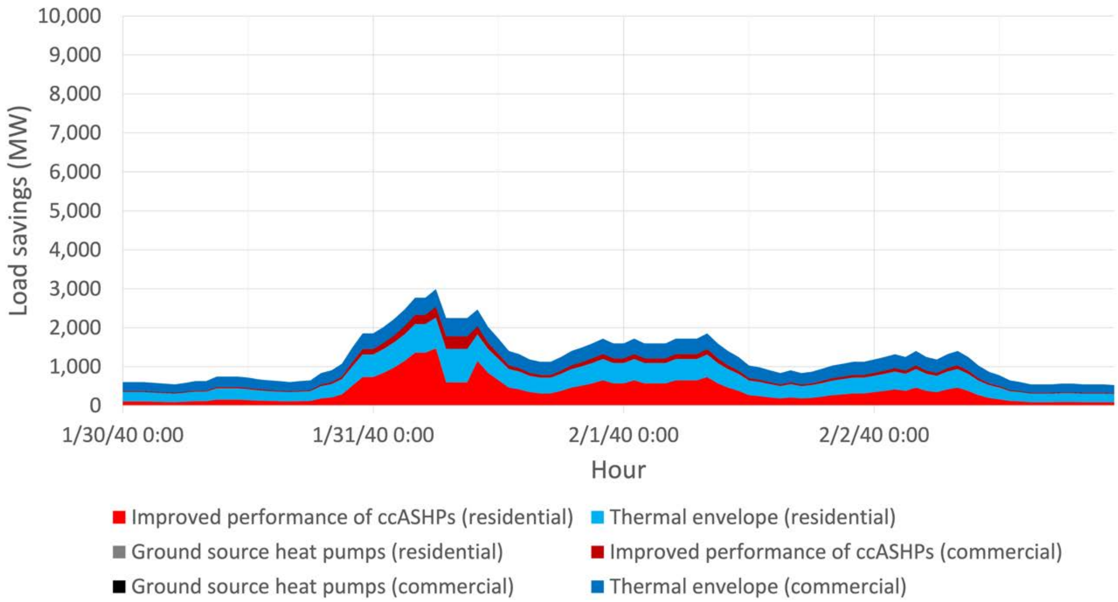

Figure 11. Load savings from figure 10 provided by each measure in the standard DSM package

Our smart package introduces a number of additional load shaping, shedding, and shifting measures realized through increased end-use connectivity, intelligence, and load flexibility. This package proves more effective than the standard package, reducing the four-day energy consumption by 1,430 GWh and shaving peak load by 11.9%, as shown in figure 12. The load profiles of water heating and EV charging change modestly as load is shifted according to the constraints outlined in table 10.

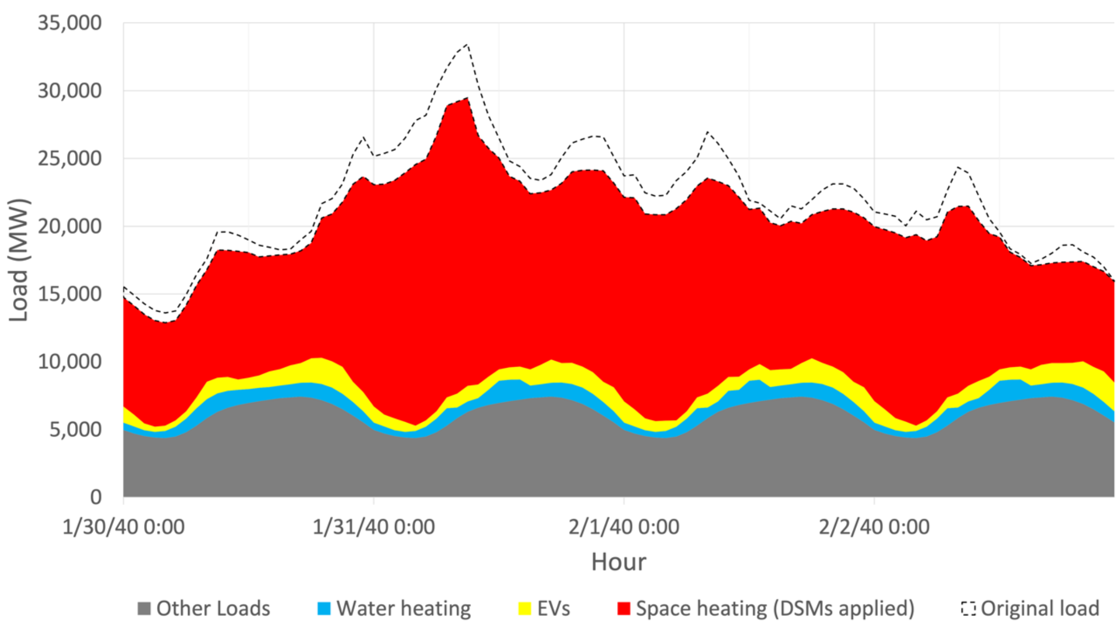

Figure 12. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (electric resistance backup) before and after applying smart DSM package. Industrial and "other" commercial loads not included.

Improved residential ccASHP performance remains the leading driver of savings under the smart package, with residential weatherization again right behind, as shown in figure 13. The most significant change comes from the inclusion of residential smart thermostats, which deliver savings on par with weatherization.

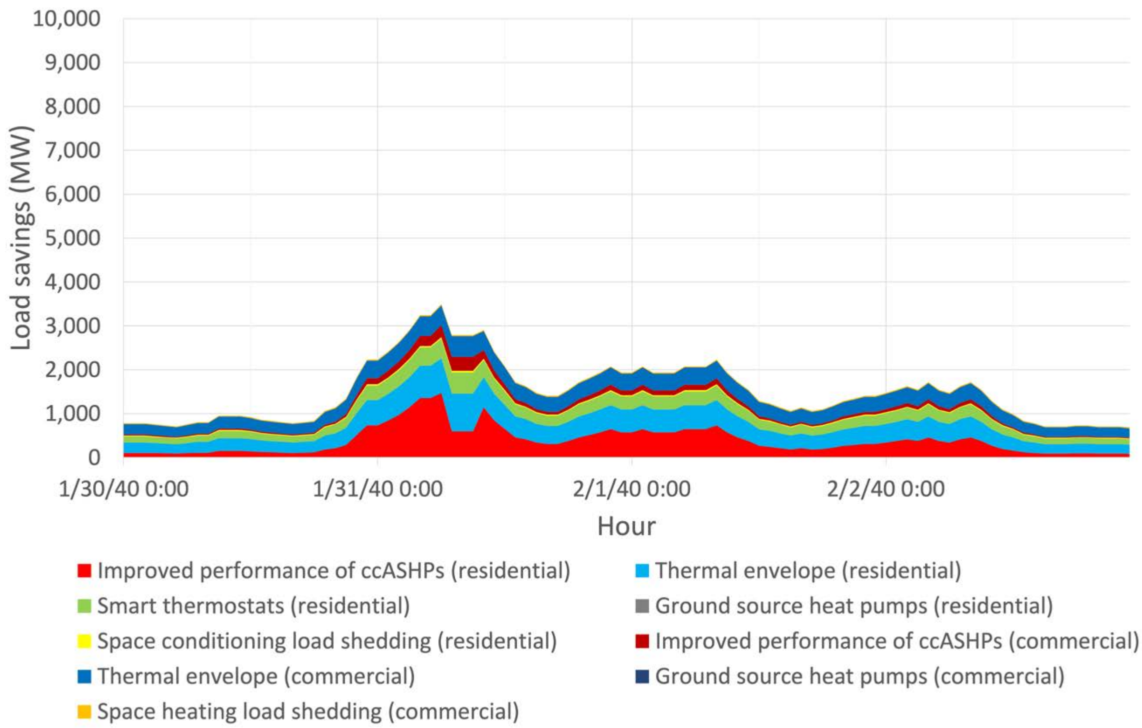

Figure 13. Load savings from figure 12 provided by each measure in the smart DSM package

The load savings realized through our deep DSM package are dramatically improved over the standard and smart cases, with a four-day energy savings of 4,370 GWh and peak load reduction of 34.2%. The inclusion of greater demand response capabilities in the form of connected hot-water heaters, managed EV charging, and electrochemical storage are effective at flattening most of the system peaks, as shown in figure 14. While the hot-water heaters were constrained to four-hour shifting, we found that peak reduction from EVs and stand-alone batteries could be achieved even with recharging that took place before the time limits reflected in table 10.

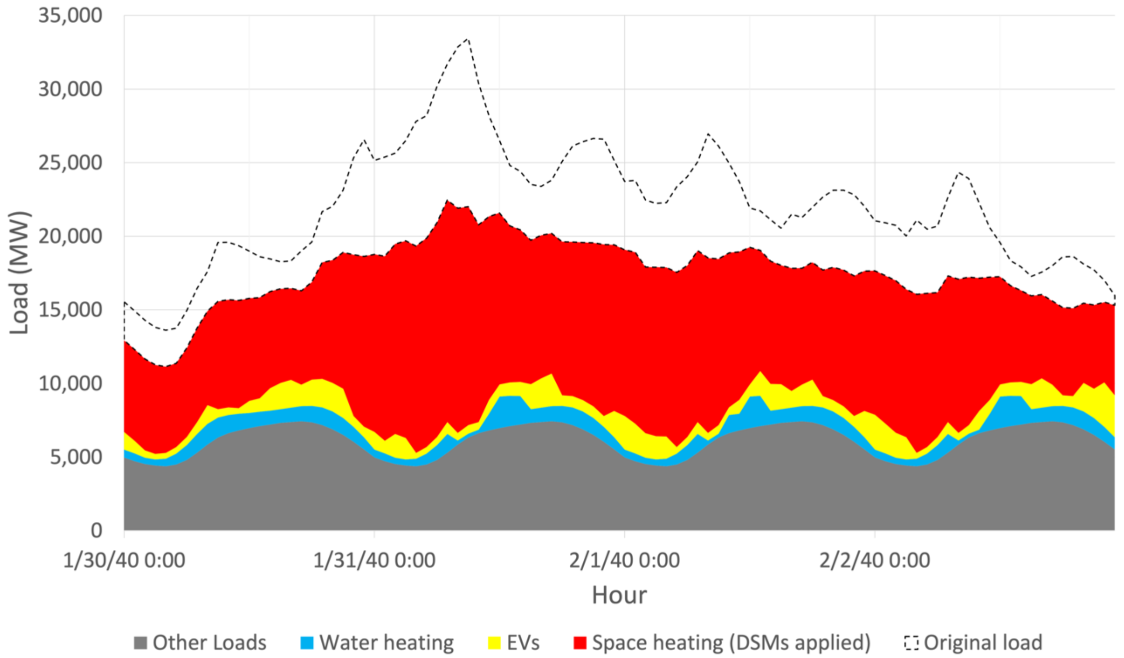

Figure 14. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (electric resistance backup) before and after applying deep DSM package. Industrial and "other" commercial loads not included.

The deep DSM package substantially increases the magnitude of savings from all measures, as shown in figure 15. Primary among these are improvements to the thermal envelope, which now includes deep energy retrofits to 10% of residential and commercial buildings. Improved performance of ccASHPs—specifically the lower changeover temperature to backup resistance heating—mitigates the dip in performance during the morning of January 31. Residential smart thermostats continue to perform well, this time at a magnitude slightly below that of residential envelope measures. We also note that load savings from these measures in all three DSM packages increase as temperature decreases, highlighting their value during periods of extreme cold.

The deep DSM package also includes intelligent thermal management in the commercial sector in the form of energy information management systems and ARCs. This emerges as our most effective commercial DSM. Improved performance of commercial heat pumps and envelope play a similarly substantial role, though in combination they remain smaller than the residential measures.

Several DSMs in our analysis offer only marginal load savings benefits relative to the others. Despite the higher efficiencies delivered by ground-source heat pumps, their impact is marginal, due primarily to the low level of deployment reflected in our DSM packages. Load shedding through temperature set-point reduction offers modest load savings, though smaller than the other measures even with an assumed uptake of 50%.

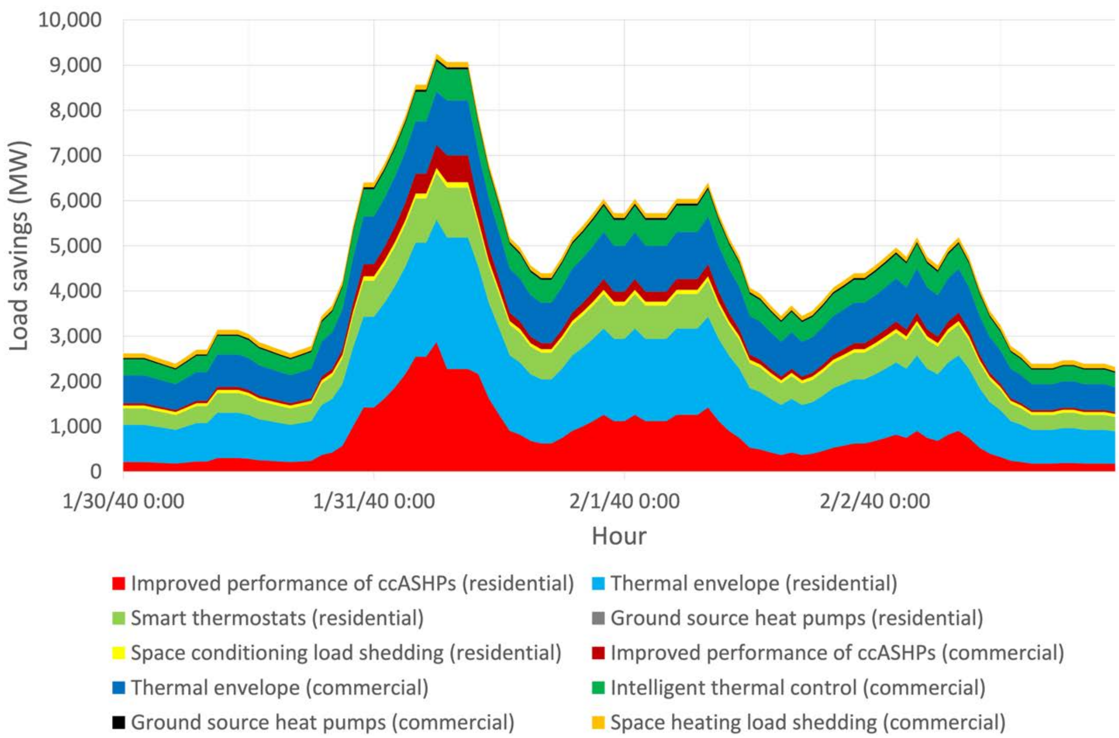

Figure 15. Load savings from figure 14 provided by each measure in the deep DSM package[33]

RESULTS — 100% ELECTRIFICATION SCENARIO

To place our EFS scenario in context, we also examined the limiting case in which the space heating load in 100% of residential buildings is handled by ccASHPs. Due to the significantly higher overall system load of 67.2 GW (which is approximately twice that of the EFS scenario), the four-day energy savings increase to 3,430 GWh, 4,090 GWh, and 9,460 GWh for the standard, smart, and deep packages, respectively. The load shape and measure savings after applying the deep DSM package are shown in figures 16 and 17, while those for the standard and smart cases are provided in Appendix B. The equivalent reductions in peak demand are 10.7%, 14.9%, and 39.1%, respectively.

[33] Because these reported load savings in all DSM packages are cumulative, interactive, and nonindependent, we have not quantified here the exact amount of savings realized by each individual measure. Rather, we apply the DSMs in sequence as percentage reductions on remaining load, then convert that to an absolute value. The sequence for residential space heating is: improved performance of ccASHPs, introduction of ground-source heat pumps, improved thermal envelope, intelligent thermal management, and space conditioning load shedding. The sequence for commercial space heating is: improved performance of ccASHPs, introduction of ground-source heat pumps, intelligent thermal management, space heating load shedding, and commercial envelope.

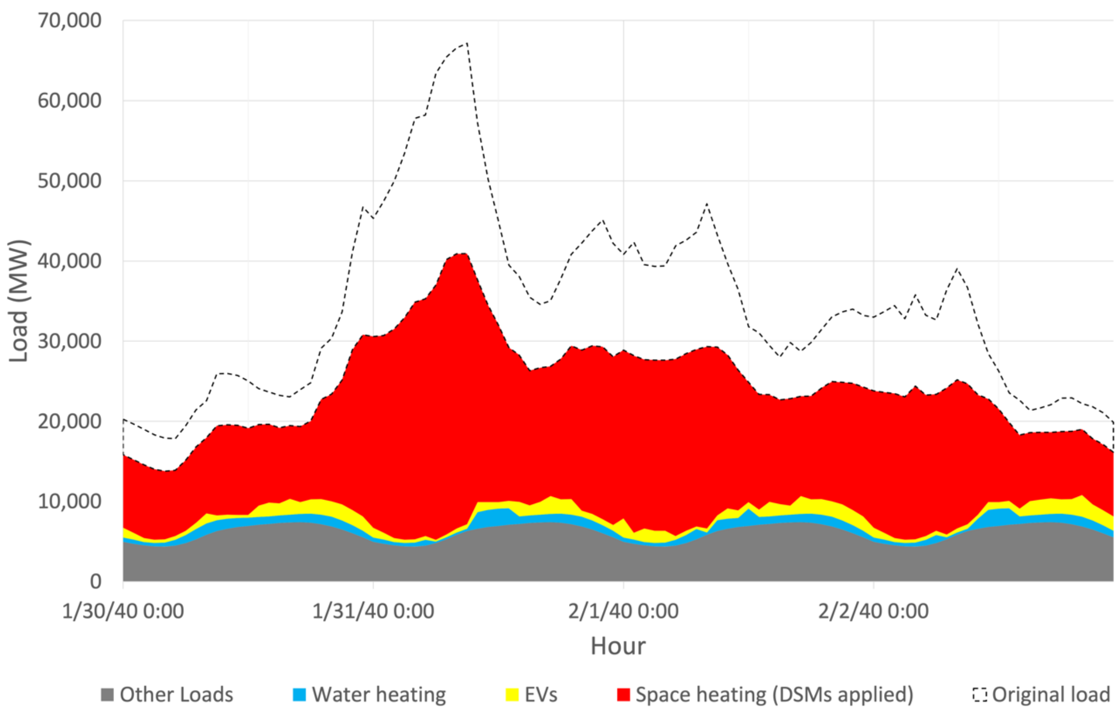

Figure 16. New England load profile during 2040 polar vortex event with 100% of residential heating load met by ccASHPs (electric resistance backup) before and after applying deep DSM package. Industrial and "other" commercial loads not included.

The electrification of 100% of residential space heating greatly improves the load savings benefit of residential space heating DSMs — particularly improved ccASHP performance, thermal envelope, and smart thermostats — both in absolute terms and relative to other DSMs. Near the system peak, ccASHP performance accounts for about 52% of all realized load savings (DR not included) as compared with about 37% in the more realistic EFS scenario.

Putting this in perspective, winter peak in ISO-NE is currently about 20 GW (inclusive of DSM). Without demand-side management, that peak load could increase by a factor of three or more during periods of deep or extended cold. DSM effectively holds that in check, limiting the increase in peak demand to about a factor of two even in the extreme case in which all residential heating is electrified and ccASHPs default to electric resistance backup.

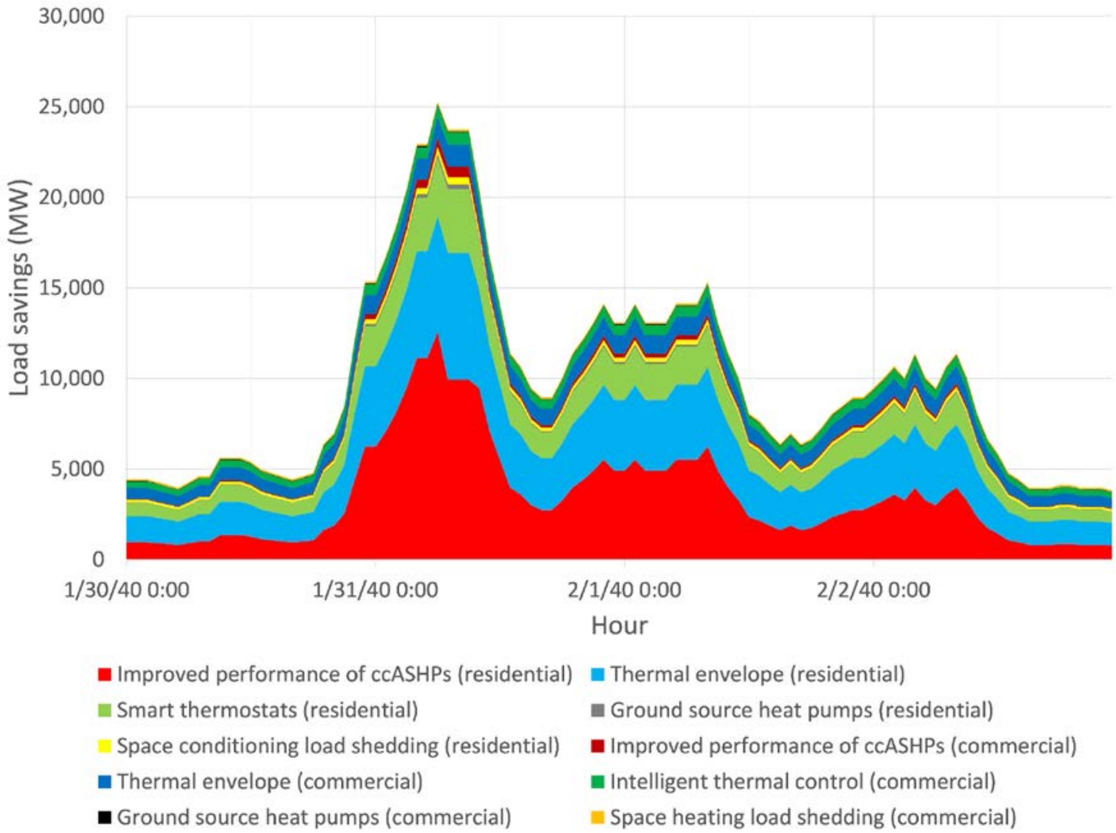

Figure 17. Load savings from figure 16 provided by each measure in the deep DSM package

RESULTS — FOSSIL BACKUP CASE

Figures 10–17 indicate that the peak system load begins to grow a couple of hours into Day 2 when the outside temperature drops below 0 °F. As a result, we examined a case in which all ccASHPs transition to a fossil-based fuel source, rather than electric resistance, for backup heating at 0 °F.

We acknowledge it is unrealistic to posit that all heat pumps will be capable of switching to fossil backup. Not all buildings with heat pumps will have natural gas connections, and not all of those that do will have the necessary hookups and controls to make such a transition possible.[34] These estimates should therefore be interpreted as a ceiling of what fossil backup could accomplish at the limit of its potential. Regardless, a complete conversion to fossil backup is bound to be suboptimal. A fraction of heat pumps continuing to use electric resistance backup will serve to flatten load and mitigate the need for ramping services to recover from the deep and rapid load reductions depicted in figures 18–21 and B5–B12. This scenario could also deliver additional emissions benefits and reduce strain on the natural gas system.

[34] Not only must controls exist, but they must be intelligent enough to avoid counterproductive situations. If the cooling set point of a heat pump is set below the heating set point of the fossil heating system, for example, both systems would run simultaneously, stressing both the electricity and gas networks.

Figure 18 illustrates the impact of the standard DSM package with fossil backup in our 1.46 million heat pump scenario. While there remains a sizable heating load driven by electric resistance heating during the beginning of the second day (and one hour on the third day), the total electric demand prior to applying any demand-side measures drops nearly 40% by using fossil backup.

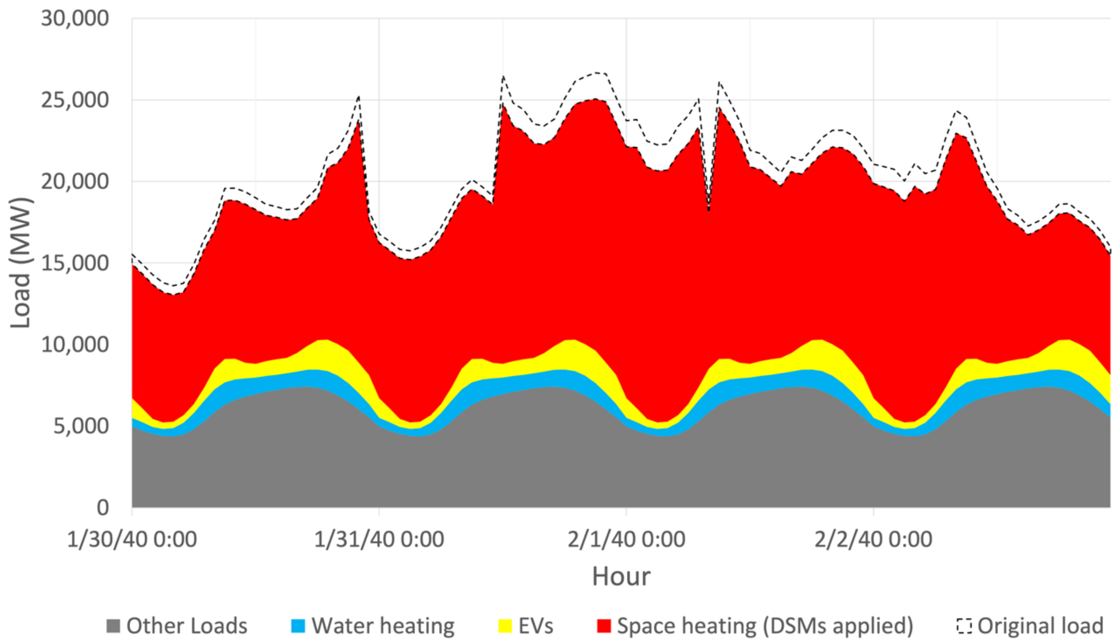

Figure 18. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (fossil backup at 0°F) before and after applying standard DSM package. Industrial and "other" commercial loads not included.

The lower electric load also lowers the demand savings from the demand-side measures, as shown in figure 19. The improved performance of ccASHPs has no impact during fossil backup hours. Both residential and commercial buildings continue to have non–heat pump electric heating, though, so improvements to thermal envelope become the dominant demand-saving measure then.

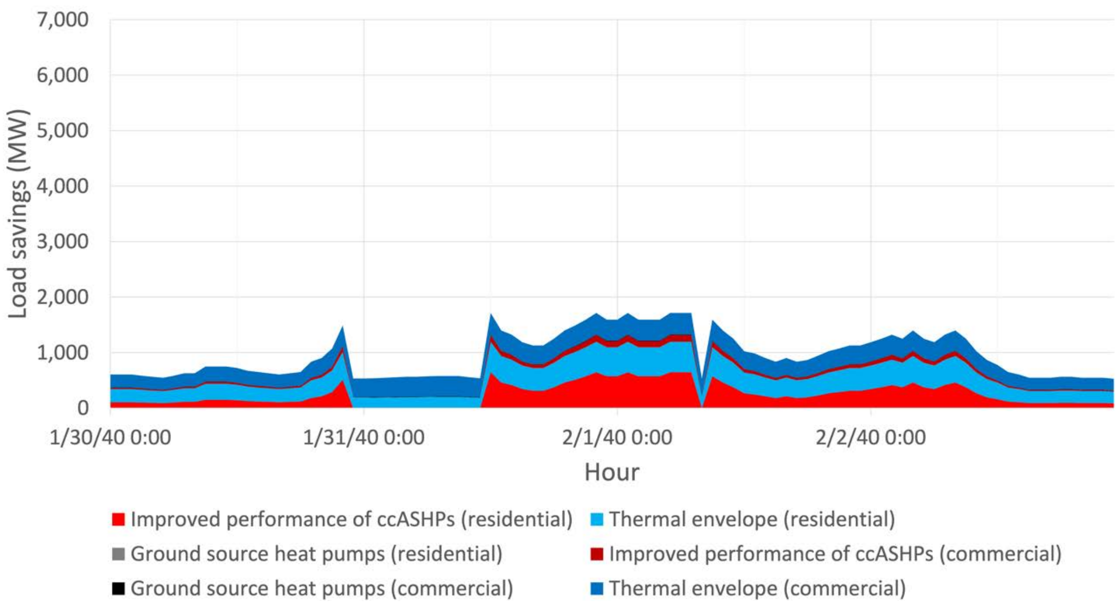

Figure 19. Load savings from figure 18 provided by each measure in the standard DSM package

Figure 20 displays the load profile for the fossil backup case after applying our deep DSM package. The load flexibility enabled by connected water heaters, EVs, and stand-alone batteries, combined with efficiency and load-shedding measures, not only reduces the remaining peak by up to roughly 20% but also enables a relatively flat system load profile.[35] The load savings for this case are presented in figure 21. As with the standard case, thermal envelope measures deliver the greatest savings during the fossil backup hours, followed by the addition of smart thermostats and intelligent commercial thermal controls.

Results from the 100% residential heat pump scenario display similar features, such as the importance of commercial envelope and intelligent commercial thermal control measures during the fossil backup hours. The combination of our deep DSM package with fossil backup lowers the four-day system peak from 67 GW to 16 GW, a value comparable to contemporary New England winter peaks. Residential thermal measures are rendered irrelevant during this period due to the absence of electric heating load. The sole exception is the GSHP measure, which, in the absence of ccASHP load, introduces additional electric load that would not exist without it. This causes the savings from this measure to run slightly negative. Load shapes and savings for this and other electrification scenarios and DSM package combinations can be found in Appendix B.

[35] No attempt has been made to apply DR measures in a way that is economically optimal. This merely shows the peak flattening potential if flexible loads are utilized specifically for that purpose.

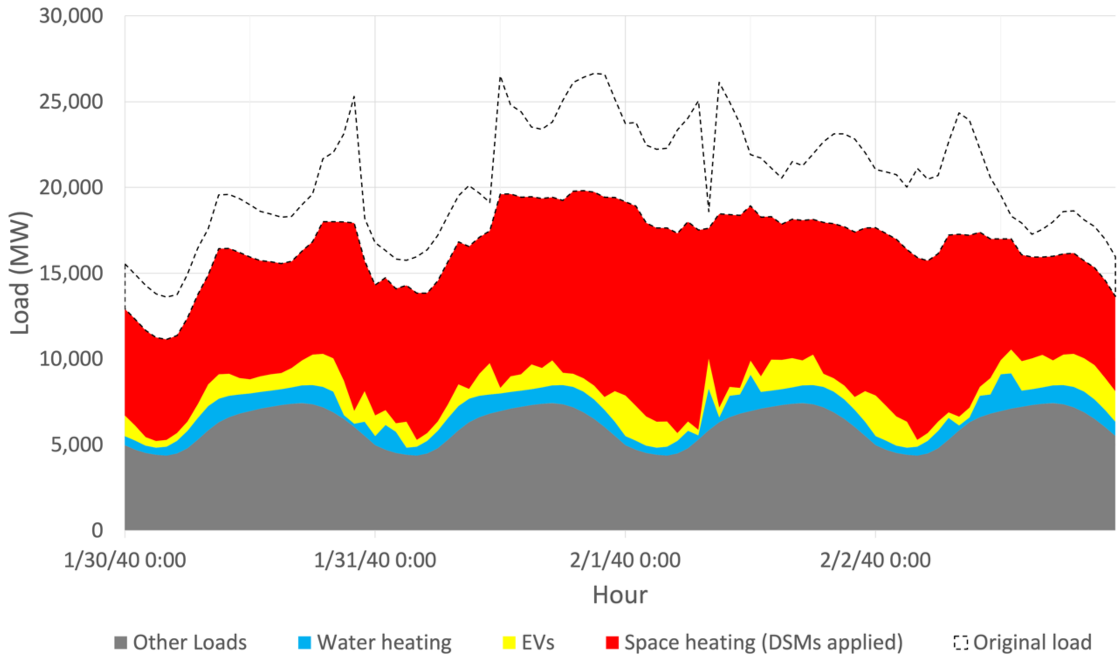

Figure 20. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (fossil backup at 0°F) before and after applying deep DSM package. Industrial and "other" commercial loads not included.

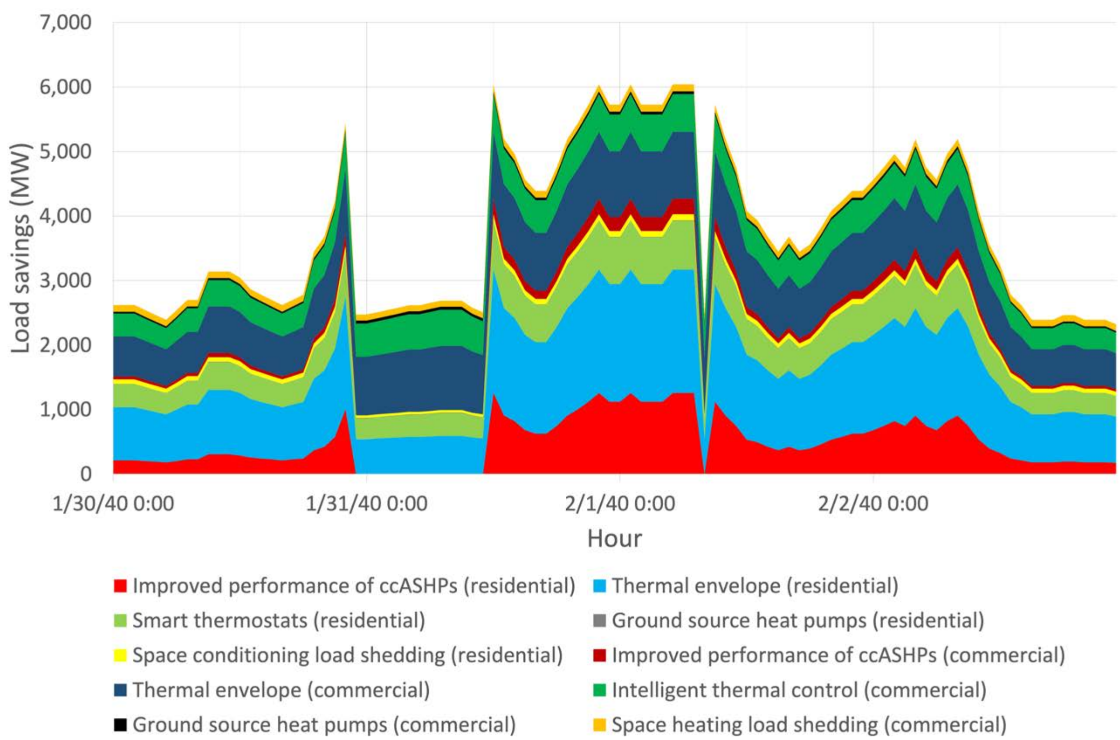

Figure 21. Load savings from figure 20 provided by each measure in the deep DSM package

RELATIVE COSTS OF DEMAND-SIDE MEASURES TO ADDRESS WINTER PEAKS

The costs associated with generating and delivering energy to serve increasing peak demands in the winter may be significant. Synapse Energy Economics developed a forecast and calculation tool to model future wholesale costs of energy in New England under several electrification scenarios. The Avoided Energy Supply Cost (AESC) study, used by regulators and utilities across the region for cost-effectiveness testing and planning, provides projections of avoided costs of electricity and natural gas from 2018 through 2035 (Knight et al. 2018). The study includes cost models and extrapolations from 2036 out to 2050 using an average rate of growth.

Here we look at two scenarios from the 2018 AESC study: Synapse's main AESC scenario, based on the latest understanding of generation, transmission, and load forecasts at the time of writing, and a "high load" sensitivity that analyzes impacts of additional load from electrification based on increased deployment of heat pumps and EVs.[36] Neither of these scenarios includes demand-side impacts.[37] The AESC forecast may therefore be compared with relative costs of DSM measures to develop a general understanding of the comparative value of supply- and demand-side resources.

Figure 22 shows Synapse's projections for wholesale energy costs in the ISO-NE market from 2018 (the year of the AESC study) to 2050. Costs are modeled up to 2035 and extrapolated beyond that using a compounding annual growth rate. The graph shows data from two scenarios: standard AESC and high load sensitivity. These scenarios are further divided into two cases: the standard winter on-peak wholesale rate, which represents weekday hours from October to May, 7 a.m. to 11 p.m. (and are classified as "winter on-peak" by ISO-NE), representing 44% of hours; and the "super peak" rate, which accounts for the top 5% of hours of peak demand in winter. The graph also shows levelized costs over 15 years for the high load scenario. The values show a substantial increase in costs during the top 5% of hours, which are 40–60% higher than standard winter "on-peak" rates. These are among the most expensive hours in the entire year. We note that changes to load within AESC's high electrification scenario do not result in substantial wholesale price increases, largely by virtue of the consistent price of natural gas between scenarios (Knight et al. 2018).[38]

[36] Synapse's high load sensitivity includes load from an additional 3.3 million EVs and assumes heat pumps replace 30% of thermal heating load in New England by 2035, with an average COP increasing from 2.3 in 2018 to 2.9 in 2035. These projections are slightly lower than our own electrification scenario. More details on inputs to the high load sensitivity scenario are provided in Appendix C.

[37] Synapse does include demand-side impacts in a separate AESC sensitivity analysis that is not highlighted in this report.

[38] While figure 22 shows a significant increase in wholesale energy prices after 2035 in the high electrification scenario, these values are extrapolated and should be considered less reliable than those indicated for years prior to 2035.

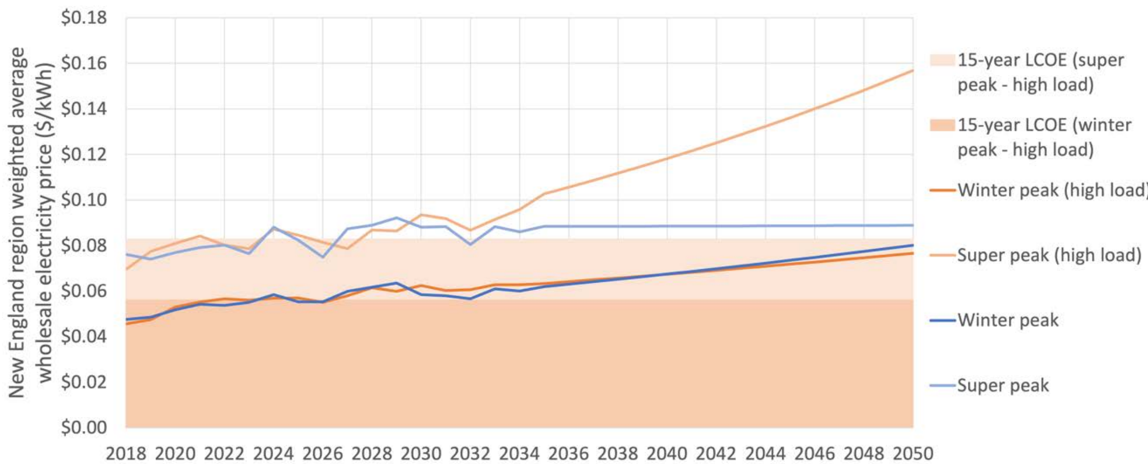

Figure 22. Wholesale costs of winter peak energy. *Source:* Knight et al. 2018. LCOE: levelized cost of electricity.

Figure 23 compares the levelized cost of electricity at the wholesale level during winter peak periods ($0.056/kWh) with the program administrator cost of saved energy for various energy-saving DSMs. These values are based on an aggregated average of program costs and savings on a national level. The cost of saved energy is based on total savings over the lifetime of a given measure, divided by the total costs to program administrators to deliver that measure, with an annual nominal discount rate of 6%.[39] We compare these values with a 15-year levelized cost of electricity during regular winter peak (not "super peak") from the Synapse AESC data, also at an annual discount rate of 6%.

[39] Many of these estimates originate from Lawrence Berkeley National Laboratory's (LBNL) forthcoming Peak Demand Savings from Efficiency study. A detailed account of inputs and methodology is provided in Appendix C.

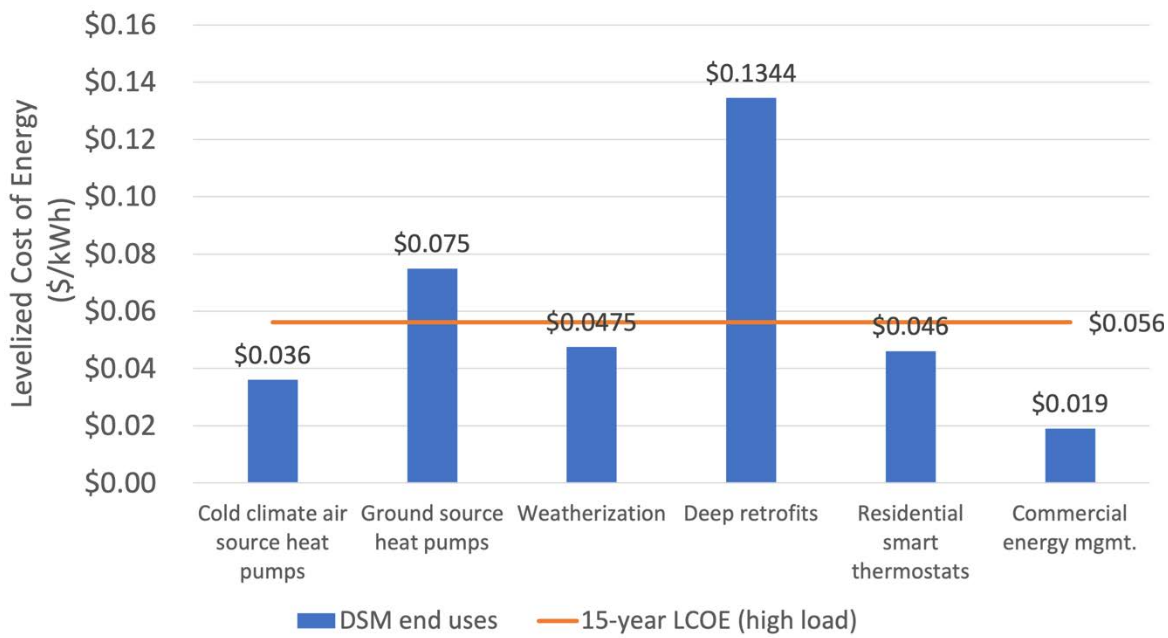

Figure 23. Levelized cost of saved energy for energy efficiency DSMs versus levelized cost of wholesale energy for winter peak periods. *Sources:* Frick and Relf 2020; Knight et al. 2018.

These savings do not factor in additional benefits such as reduced emissions; improved comfort, health outcomes, and indoor air quality; capacity and T&D impacts (discussed below); and demand reduction induced price effects (DRIPE).[40] By comparing these values, we can see that on a pure cost of energy basis, most efficiency measures (high-efficiency cold-climate heat pumps, weatherization, smart thermostats, and commercial energy management) deliver energy savings at a lower cost than purchased power during the 33% of hours in a year that are classified as "winter on-peak."[41]

Two of the measures (GSHP and deep retrofits) have higher costs. Both are nascent technologies that are currently reaching only a small portion of the market.[42] Over time and with additional RD&D, increasing market penetration and a workforce that is more knowledgeable about these measures may help drive down lifetime costs. An example of a market transformation effort to lower deep retrofit costs comes from New York State, where NYSERDA has been working to develop a net-zero affordable housing market based on a successful European deep-retrofit system called Energisprong (NYSERDA 2020b).

[40] DRIPE is a market-based phenomenon wherein lowering peak demand puts downward pressure on wholesale prices.

[41] The New England analysis was selected to explore how DSM would perform under extreme conditions. We note that most "normal" winters will not require our modeled level of resources, and therefore, our polar vortex case may not represent a large proportion of avoided costs.

[42] LBNL's 2014 Deep Retrofit meta-analysis finds fuel conversions in deep retrofits (i.e., switching from gas to electric heat, or vice versa) were relatively infrequent at the time of study. Most deep retrofits were focused on envelope measures and kept the same type of fuel in the home that existed prior to retrofit (Less and Walker 2014).

In terms of capacity benefits, a study supplementary to Synapse's AESC finds that, given the current summer-peaking nature of the ISO-NE grid, winter peak demand reductions do not meaningfully influence the reserve margins that dictate grid planning decisions (Knight et al. 2020). However, the forecast shift to a winter-peaking system may increase the role of demand-side measures in avoiding buildout of new generation and transmission assets. More details on capacity costs and the cost of saved peak demand through various demand-side measures can be found in Appendix C.

APPLICABILITY TO OTHER REGIONS

The analysis above illustrates the potential that DSM has to significantly mitigate winter peaks. However, every region has unique characteristics. The best DSM package for New England may not be optimal elsewhere. Solutions will be most transferrable if regions share similar climates, renewable energy profiles, and end-use saturations.

The electrification of space heating is a key driver of winter peaks, so any DSMs that reduce heating demand or the electricity needed to satisfy it are likely to be effective across regions. This includes improved heat pump performance, envelope improvements, smart thermostats, and other forms of space heating management. Measures that address water heating load (e.g., demand response, conversion to heat pump water heaters), while less significant mitigators of peak demand, are also likely to be effective across regions.

A general approach to using DSM to address winter peaks begins with developing an understanding of a region's specific set of end-use load shapes. Yet this is something much of the industry is currently lacking.[43] Useful input can be gathered through end-use saturation surveys; interviews with local equipment manufacturers, contractors, and retailers; AMI data; and machine learning.

For example, Duke Energy used this combination of information to better understand a load spike it observed during the mornings of its winter peak days. It identified electric resistance heating that turned on at around 40 °F as a primary driver. Through engagement with trade allies, Duke Energy discovered that contractors, in an effort to maximize heating speed and minimize repeat house calls, establish higher changeover temperature set points that lead to higher energy consumption and exacerbation of winter peaks (T. Hines, principal, Tierra Resource Consultants, pers. comm., July 10, 2020).

In New England, there were only a handful of hours in our simulation during which outdoor temperatures dropped below the electric resistance changeover temperature of quality ccASHPs (see figures 8 and 9). These results will likely translate to regions like the Southeast and mid-Atlantic. Grid planners should be more careful, though, about extending conclusions regarding ccASHP DSMs to areas like the Midwest, where temperatures can plummet for many hours below the changeover temperature during extreme cold weather events. In this situation, ground-source heat pumps may be more valuable. Given that

[43] A three-year effort to develop up-to-date load profiles is currently underway by researchers in LBNL's Electricity Markets & Policy group (Frick 2019).

heating systems are constantly improving, it is imperative for utilities to keep abreast of new technologies.

Utilities should also understand how measures will affect their particular customer base. For example, BC Hydro executed a winter measure in which residential space heating set points were reduced by one to three degrees during a winter peak period. While some customers (such as families with young children) chose to override the DR event, the number was lower than anticipated. In contrast, customers were less tolerant of temperature increases resulting from preheating homes in advance of a peak (C. Intihar, program manager, BC Hydro, pers. comm., August, 6, 2020). Experts observe that regardless of jurisdiction, proper rate designs are needed to incentivize customers to preheat their homes or agree to heating temperature setpoint reductions.

Utilities should also explore whether their regions' economies introduce unique opportunities or challenges for winter DSM. This includes identifying local seasonal or coincident loads like snowmaking or street lighting. There also may be differences in expected EV charging during winter peak periods. If those periods coincide with extreme weather, additional opportunities may exist in delaying the startup of schools or commercial buildings by a few hours.

On the policy side, some measures may prove more effective if they are required by building codes or incentivized by a regional carbon market. Utilities can also reduce costs by leveraging their existing tools and programs (e.g., summer smart thermostat programs, load control switches) to deliver versions applicable for winter.

Example of Winter Peak Planning through DSM: Duke Energy

Duke Energy recently undertook its own Winter Peak Shaving study to understand the potential for energy efficiency and demand response to deliver demand-side savings during winter peak periods for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems. Duke partnered with Tierra Resource Consultants, Dunsky Energy Consulting, and Proctor Engineering to identify innovative rate initiatives and utility programs for this purpose. They developed a screening approach that identifies DSMs aligned with Duke's specific winter peak needs, collects stakeholder input, targets technologies that customers are adopting, considers innovative program designs, "winterizes" existing programs, combines smart programs and rate designs, and finds quick-start opportunities. Duke has already broken out opportunities by customer segment, targeted end use(s), and program type (e.g., on-peak rate signal, peak savings rewards, load shift/DR, energy efficiency). It found a 2041 winter season DSM potential of 4.3% and 4.4% of the DEC and DEP forecast loads, respectively, realized mostly through the residential sector via new rates and expanding mechanical solutions like smart thermostats, battery storage, and electric vehicles (Duke Energy 2020a, 2020b, 2020c).

Discussion of New England Analysis

Our 2040 electrification scenarios show that increased penetration of ccASHPs increases winter peak system load significantly. From a current winter peak baseline of about 20 GW, adding 1.46 million residential heat pumps increases winter peak by 67.5% (to 33.5 GW), and converting all residential heating to ccASHPs increases winter peak by 235% (to 67

GW).[44] For the 1.46 million HP scenario with electric resistance backup, the three DSM packages that we modeled could yield a range of savings: 6.7% for our standard (i.e., business as usual) case, 11.9% for the smart package, and 34.2% for the deep case. Table 11 summarizes our findings for estimated peak reductions and energy savings with different DSM packages and two penetration levels of heat pumps using electric resistance or fossil fuel–based heating backup.

Table 11. Four-day energy savings and peak load reductions from the application of three DSM packages under two electrification scenarios and one fossil fuel backup case

DSM package	1.46 million HP (EFS) scenario			100% HP scenario		
	Energy savings (GWh)	Peak reduction (electric backup)	Peak reduction (fossil fuel backup)	Energy savings (GWh)	Peak reduction (electric backup)	Peak reduction (fossil fuel backup)
Standard	1,160	6.7%	25.2%	3,430	10.7%	40.9%
Smart	1,430	11.9%	27.9%	4,090	14.9%	43.8%
Deep	4,370	34.2%	40.8%	9,460	39.1%	55.3%

As observed earlier, winter peak demand in the 100% heat pump scenario more than triples. Our smart and deep packages would limit this increase to a doubling. The estimates in table 11 show the impacts of different backup heating technologies (electric resistance versus fossil fuel) on DSM packages to reduce winter peak demand. Clearly, if heat pump systems revert to resistance heating during extremely cold weather, they greatly increase electric demand relative to fossil fuel backup.

Our analysis shows that continuing current DSM programs in New England can have a large impact on reducing both total energy consumption and winter peak demand. For the EFS scenario, improved performance of ccASHPs, then residential weatherization, have the greatest positive impact in weathering our polar vortex event. These results reflect the dominance of residential winter heating loads that drive winter peak demand. Weatherization reduces heating loads, and high-efficiency ccASHPs use less electricity to meet those loads. Commercial measures included in the standard package of current DSM programs have a somewhat smaller overall impact since the EFS scenario assumes that much commercial heating remains fossil fuel–based in 2040.

Inclusion of a wider set of smart (GEB) technologies in the smart DSM package yields higher energy and peak demand savings in the EFS scenario. The greatest relative impact is on reducing peak demand—almost doubling the reduction, from 6.7% (standard package) to 11.9%. Projected energy savings increase by 23%. These results demonstrate the potential for smart technologies not only to shave or shift demand, but also to reduce total energy use. Smart residential thermostats yield the largest additional savings when comparing the

[44] The baseline electrification scenario assumes the average residential/commercial heat pump has a COP of 1.88 at 5 °F.

smart DSM package with the standard package. These additional savings from smart thermostats are comparable to those resulting from weatherization.

As would be expected, the deep DSM package has a large impact on energy use and peak winter demand. Four-day energy savings in the EFS scenario increase dramatically to 4,370 GWh. Peak demand decreases by 34.2%. This large peak demand reduction results in part from flattening most of the system peaks through a set of demand response technologies, primarily connected water heaters, managed EV charging, and battery storage. The large increase in energy savings is primarily by virtue of an increased number of deep retrofits.

While commercial DSMs in the standard and smart packages have relatively small impacts, such measures show a much larger impact in the deep package. Intelligent thermal management in the form of energy information management systems and advanced rooftop controls emerges as the most effective commercial DSM. Improved performance of commercial heat pumps and envelope also play a substantial role, though in combination they remain smaller than the residential measures. This situation could change if the commercial sector were to electrify at a level more in line with the residential sector. The corresponding impacts of improvements to the performance of commercial building envelopes and heat pumps would increase in this case.

Under the scenario in which 100% of residential heating load is met by ccASHPs, the impacts of the DSMs included in each package are greatly magnified. With an overall system load about twice that of the EFS scenario, the four-day energy savings increase as shown on the right side of table 11. The respective share of load reductions attributable to residential heating measures increases as would be expected in this scenario since electrification of heating accounts for a large share of the overall increased system load. Near the system peak, ccASHP performance accounts for about 56% of all realized load savings (DR not included) as compared with about 36% in the EFS scenario.

Finally, we observe the greatest peak load reductions in our fossil backup case. Shifting ccASHPs away from inefficient electric backup heating systems during the coldest temperatures can cost less than building new generation or grid-scale storage capacity. While the emissions resulting from fossil combustion would be confined to a limited number of hours per year, this approach carries the risk of locking in natural gas infrastructure that would be used during nonpeak hours. Such an outcome could be avoided by requiring the use of climate-friendlier fuels, such as renewable natural gas.

POLICY, PROGRAM, AND MARKET OPPORTUNITIES TO UNLOCK DSM AS A WINTER PEAK SOLUTION

The ability of energy efficiency and demand response to reduce summer peak demand is well proven over decades of program experience. Using similar strategies to address winter peak demand, by contrast, is still emerging and largely untested. Our analysis shows, however, that many of the same types of measures in current DSM programs will yield beneficial winter peak demand impacts. Reducing overall heating loads in homes through weatherization can have large impacts on winter peak demand, particularly as such demand grows in both cold and warm climates due to electrification of home heating. Using smart control technologies for home heating systems provides a valuable system resource. With such connected, grid-interactive controls, grid operators can initiate various customer responses to shave or shift loads, such as by cycling heat pumps off for short periods or reducing temperature set points.

Our analysis suggests that the residential sector offers greater potential to reduce winter peaks in New England in 2040 than does the commercial sector, which largely reflects the expected slower transition in commercial buildings away from fossil fuels for space and water heating. Since winter peak demand in cold climates is driven by weather conditions, reducing heating demand generally provides the greatest opportunities for reducing winter peaks.

These findings suggest key opportunities to unlock DSM as a winter peak solution. Programs and policies that support and incentivize energy efficiency for residential buildings of all types (single family and multifamily) can provide large benefits for managing winter peak demand. This includes efforts in regions with relatively high levels of electrification, like the Southeast, where sometimes decades-old heat pumps and electric resistance heating could be replaced with more efficient ccASHPs. Improving the performance of heat pumps is another key to slowing winter peak demand growth, especially as the number of heat pumps grows. Equipment standards and incentives for high-efficiency units, along with marketing to consumers and training of contractors and suppliers, can help drive markets for high-performance heat pumps.

In addition to mitigating winter peaks and constraints, the combination of weatherization and improved heat pump performance provides an opportunity to meet resilience goals. The reduction in electric load makes outages less likely, but when they do occur, a tighter thermal envelope can help building residents stay warm longer. The benefit is similarly valuable in summer, as well-weatherized buildings can reduce heat flow into living space in the event that air-conditioning is unavailable.

Utilities and other program administrators can apply lessons from early experiences with DSM that targets reducing winter peak demand. While such experiences to date are limited, there are promising examples, as discussed earlier, such as Efficiency Maine's Heat Pump Rebate Program, NYSERDA's Comfort Home pilot, NEEA's Heat Pump Water Heater Initiative, and Great River Energy's Water Heating Peak Load Reduction & Load Shifting Program. As illustrated in our analysis, the addition and expansion of smart HVAC control technologies can greatly increase the impact of energy efficiency programs, such as residential weatherization, to reduce winter peak demand.

The efficacy of improved ccASHP performance as a demand-side measure speaks to the critical need for continued technological innovation. This can arise through normal market forces but will be accelerated with federal R&D investments facilitated by, for example, DOE's Building Technologies Office. Such acceleration of R&D can be part of a broader market transformation effort to increase penetration of high-performance technologies, helping to bring down costs and increase customer acceptance and adoption of targeted high-efficiency technologies and equipment. Deep retrofits and ground-source heat pumps could similarly benefit from greater R&D investments and application of market transformation. Such efforts could include collaboration among utilities/program administrators, trade organizations, stakeholders, and manufacturers to set tiers of performance standards, such as those led by the Consortium for Energy Efficiency for residential central air conditioners and air source heat pumps. Other market initiatives needed to increase the availability and adoption of ccASHPs are education and outreach to customers so they understand and invest in this technology, and professional education and training for suppliers and contractors who install and maintain HVAC equipment and systems.

In regions with wholesale capacity markets (e.g., ISO-NE, PJM), capacity commitments can be procured through auctions held three years in advance of deployment.[45] While the installation of efficient ccASHPs and connected hot-water heaters can be accomplished relatively quickly, replacement of equipment may not be economical until the end of its lifespan, which is often more than a decade. Program administrators and grid operators therefore need longer planning horizons to anticipate and integrate such potential additions to demand-side resource portfolios that result from equipment change-outs to technologies with much higher performance. This highlights the need to develop the DSM market and demonstrate each technology's viability and cost effectiveness given various time frames. Additional challenges like establishing the role of third parties, improving valuation and rate designs, evolving utility business models, and adjusting electric system infrastructure and capabilities must also be addressed.

COSTS

Our analysis shows that most of the efficiency measures we examined that are capable of providing winter peak demand savings can and do deliver such savings at lower cost than purchased power during the hours that are classified as "winter on-peak" by ISO New England's rate schedule.[46] These savings include only program costs and energy benefits. DSMs included in our analysis that cost less than the levelized cost of energy on a wholesale level are:

- Cold-climate air source heat pumps
- Weatherization
- Residential smart thermostats
- Commercial energy management

We found that two of the measures we examined, ground-source heat pumps and deep retrofits, have higher costs than levelized wholesale costs during winter on-peak hours. These measures require relatively large initial investments. Advances in technologies and program implementation may help bring these costs down.

Our cost analysis does not include additional benefits such as reduced carbon dioxide and other air emissions; improved comfort, health outcomes, and indoor air quality; demand reduction induced price effects (DRIPE); and capacity impacts.

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[45] MISO and NYISO also hold capacity auctions, but only months in advance of deployment. NYISO does not currently allow energy efficiency to participate in capacity auctions, but FERC Order 2222, which requires wholesale market operators to allow DERs to offer grid services where able, may change that.

[46] ISO New England defines its "winter on-peak" rates as effective from 7 a.m. to 11 p.m. for October through May.

A key point that emerges from our cost analysis is that most of the energy efficiency measures are cost effective based on consideration of the value of energy savings only. The value of peak demand reductions is difficult to estimate, but past experience clearly shows that electricity costs can rise sharply during extreme winter events. Reducing peak demand via demand-side options has a correspondingly high value. There also are savings from avoided T&D costs. The peak savings from energy efficiency can be viewed as a high-value bonus benefit for offsetting the need to procure electricity supplies at much higher cost.

Recommendations

Application of DSM to address winter peaks will require support and collaboration among utilities, grid operators, regulators, and customers. Many of the necessary program and policy elements may be in place, but these generally are not targeted and adapted to address winter peak demand, nor are they set up to scale to the size of the challenge. We offer the following recommendations to foster and support the use of DSM as a cost-effective means to address winter peak demand.

For regulators/policymakers

- Create requirements for utilities to establish goals for winter peak demand reductions in regions where winter peaks have the potential to surpass summer peaks and available resources to meet winter peak demand would be insufficient[47]
- Require utilities to consider demand-side solutions when analyzing options to meet winter peak demands, creating parity for demand and supply options in integrated resource planning
- Ensure that screening of DSM programs and technologies accurately and fully values the benefits of reducing winter peak demand
- Encourage and approve, as appropriate in service areas where advanced metering infrastructure is in place, rate structures and pricing for electricity that incentivize customers to reduce winter peak demand. Pair advanced time-varying rate structures with program offerings that enable customers to best benefit from them[48]
- Support utility research and demonstration of demand-side solutions to winter peak problems

For utilities/program administrators

- Adapt existing DSM programs to incorporate technologies and measures that specifically target winter peak demand reduction
- Analyze customer loads to develop targeted recommendations for measures that reduce winter peak demand

[47] The Massachusetts 2019–2021 energy efficiency plan term sheet, for example, supports the state's winter reliability efforts by targeting winter electric demand savings of 500 MW (Molina 2018; MA EEAC 2018a).

[48] See York, Relf, and Waters 2019 for an examination and assessment of integrated energy efficiency/demand response programs.

- Expand weatherization and home retrofit programs to increase participation and savings
- Incentivize and promote adoption of high-efficiency heat pumps, and support market transformation toward the most efficient models
- Integrate demand response technologies (such as smart thermostats) and advanced rate designs into energy efficiency programs to fully capture the resources' value streams, improve effectiveness of marketing and implementation, and provide a more streamlined, positive customer experience.
- Develop and implement marketing and outreach to inform and educate customers about the value and importance of taking actions and investing in solutions that reduce winter peak demand

For planners (ISOs/regional markets/utility planners in vertically integrated markets)

- Ensure parity in integrated resource planning and distribution system planning for both supply- and demand-side options when developing solutions for meeting winter peak demand
- Establish market rules and tariffs that readily enable distributed energy resources to participate in wholesale markets

AREAS FOR FUTURE RESEARCH

These results illustrate the potential that a handful of demand-side measures have for reducing winter peaks. There are several improvements that could be made to this analysis. A full net load profile that includes renewable energy and other commercial and industrial loads could be introduced to better understand the full system demand that would need to be addressed. More nuanced understanding of the building envelope and heat flows could be modeled to improve accuracy on hourly heating loads.

We recommend several future areas of inquiry to improve upon this research, including extending the analysis to other regions like the Southeast, which already is experiencing winter peaks in some areas, and the Midwest, where impacts of cold weather can be extreme. Suggested areas for future research include:

- Detailed cost-effectiveness testing of various demand-side solutions
- Analysis of the effectiveness of programs that address winter peaks, focusing on specific lessons learned about program design for program administrators
- Analysis of the interactions between the electric and natural gas systems during peak periods, including characterization of constraints on the natural gas system
- Investigation of the feasibility of dual-fuel systems in residential and commercial buildings in regions with cold climates, such as New England
- Extrapolation and analyses of larger capacity needs and system reserve margins
- Analysis of net load — accounting for the impact of renewable energy resources and examining the timing of greatest system benefits from energy efficiency savings

- Exploration of the potential for behind-the-meter thermal storage in commercial buildings and other forms of thermal management, such as preheating of residential buildings
- Comparison of DSMs to a wider array of decarbonization policies and technologies, particularly where costs and benefits of each may conflict

Conclusions

Electrification and decarbonization are transforming utility markets and energy technologies in our homes and businesses. The signs are strong that these transformations will increase electricity demand throughout the year. Some of the largest increases may occur in winter due to electrification of heating technologies. Available demand-side solutions align with efforts to decarbonize our economy as they avoid reliance on fossil fuel generation to meet peak demand. Continuing and expanding customer energy efficiency and demand response programs can help avoid future winter peak demand problems, especially by advancing measures and technologies that yield large winter demand savings.

In cold climates the most effective solutions are naturally those that either reduce heating loads or meet heating loads at higher efficiency. Energy efficiency and demand response complement each other and are best accomplished through comprehensive, integrated customer offerings.

The demand-side solutions for winter peaking require somewhat unique approaches due to the character of winter peaks and loads targeted. Some lessons and technologies used in summer peak management, such as smart thermostats and water heater controls, can be applied to winter peak management as well. Flexible loads will become important to addressing winter peak demand, just as they are in addressing summer peaks and shifting load curves.

Investment in the energy efficiency of new and existing buildings is a critical strategy to mitigate the cost and reliability impacts of winter peaks, especially as space heating becomes electrified. This will dampen demand growth and reduce the need for new resources to meet higher winter peak demand.

Energy efficiency can deliver peak savings at lower cost than projected levelized wholesale power costs during winter peak periods. Measures included in our analysis are cost effective (i.e., benefits exceed costs) on the basis of energy savings alone, without even considering the value of peak demand reductions. These can vary widely, especially during extreme winter weather events when markets and energy supplies can be constrained. Other nonenergy benefits, such as improved comfort and indoor air quality, are also not included in our analysis. In short, energy efficiency measures that are cost effective based on energy savings alone (kWh) can yield additional benefits as flexible demand resources.

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Appendix A. Electrification Scenarios, Technology Baselines, and DSM Packages

Our analysis examines what may be referred to as a "high electrification scenario." This matches the language used by the NREL Electrification Futures Study (EFS), which is a multiyear effort to explore the impacts of widespread electrification in all U.S. economic sectors. The EFS is composed of several reports, but we limited our focus to its *Scenarios of Electric Technology Adoption and Power Consumption for the United States* report (Mai et al. 2018). This is a market-based report in which sales shares are processed and scenarios are generated through a bottom-up energy accounting model, EnergyPATHWAYS, that captures a detailed stock rollover of the energy system. Results are provided annually at the state level.

EFS provides three primary adoption scenarios. The first is the *reference scenario*, which has the least incremental change and is based on EIA's Annual Energy Outlook reference forecast. Its *medium scenario* captures widespread electrification among what EFS envisions as the lowest-hanging fruit—opportunities with the greatest case for adoption. Its *high scenario* assumes a combination of technology success and policy drivers that lead to a high degree of electric technology adoption. We based our analysis on this high scenario as it most closely aligns with New England's state climate goals and provides the more challenging scenario for DSMs to address. It is important to note that the EFS outputs are not forecasts. Rather, they are internally consistent technology adoption scenarios that could plausibly occur over the next 30 years.

Our work was further informed by electrification load projections from ISO-NE (Black 2019, 2020a, 2020b) and an independent confirmation of its work from Synapse (Goldberg et al. 2020). Like the EFS, Synapse also reports three cases: business as usual (low), Policy (medium), and Greenhouse Gas Target (high), which differ in that these are policy-based *forecasts* rather than scenarios. Synapse's high scenario is based on each state's 2030 climate goals and assumes the bulk of the electrification in the space heating sector will occur over the next decade. We used the Synapse forecasts to estimate the number of heat pumps and EVs that will be in operation in New England in 2040. We extrapolated the number of heat pumps expected in 2029 to 2040, leading to one of our two electrification scenarios in which every residential building is serviced by a ccASHP. We cross-referenced Synapse's 2029 EV forecast and its extrapolation to 2040 with the EFS, ultimately estimating that there will be about 3 million EVs on the road in 2040. Additional information on how we derived this estimate is provided in the main body of this report.

SPACE HEATING

In the EFS electrification scenario we assumed 1.46 million ccASHPs will be deployed in New England residential buildings in 2040 (as reflected in the EFS high scenario). We assigned one heat pump to each new residential building built between now and then and distributed the remainder randomly among existing homes that currently have a nonzero electric heating load. The homes with nonzero electric heating that do not receive a heat pump are assumed to be heated by electric resistance heating with a COP of 1. We assumed the remaining homes will continue to be heated by nonelectric sources and therefore will not contribute to electric system demand.

We used a representative sample of thermal properties of the New England building stock to calculate how outdoor temperature will impact electric demand. The RECS database contains 246 New England homes (i.e., those in census division 1) with a reported space heating load, representing a stock of about 5.5 million buildings. We let q_i equal the space heating load per hour per degree day (hereafter *space heating load density*) in the i^{th} RECS building and calculated it as

$$q_i = \frac{annual\ heating\ consumption\ in\ "house\ i"}{24 \cdot annual\ heating\ degree\ days} = \frac{Q_{i,annual}}{24 \cdot HDD_i}.$$

A similar statistic was derived for each commercial building using CBECS.

Each building will have an associated hourly space heating load Q_i such that

$$Q_i = \begin{cases} (65 - T)q_i & \text{if } T < 65°\text{F} \\ 0 & \text{otherwise} \end{cases},$$

where T is the average hourly outdoor temperature in degrees Fahrenheit. The mapping between heating demand and electric load will differ according to heating fuel, as depicted in table A1.

Table A1. Mapping between heating demand and electric demand by fuel type

Primary heating source	Mapping
Fuel oil, kerosene, propane	$E = 0$
Natural gas	$E = 0$
Wood	$E = 0$
ASHP	See below
Electricity (non-ASHP)	$E = Q$

We assumed that non-ASHP electric heating is provided by electric resistance and that there is a complete conversion of electrical energy to heat. The hourly electric demand E required to operate the heat pump will vary based on Q, the heat pump coefficient of performance COP, and the type of backup fuel the heat pump switches over to when T drops below the changeover temperature T_c.

The work provided by a heat pump equals the electric load such that $E_i = Q_i/COP$. Cold-climate air source heat pump performance is temperature dependent, and we parameterized a quadratic $\mathrm{COP}(T)$ based on an analysis of the performance of best-in-class heat pumps (Nadel and Perry 2020). In Nadel and Perry's analysis, the top four units based on integrated energy efficiency ratio (IEER) were selected from the AHRI, ENERGY STAR Most

Efficient, and NEEP Cold Climate databases (AHRI 2020; ENERGY STAR 2020; NEEP 2020). This yielded coefficient of performance curves for both residential- and commercial-scale units shown in figures 8 and 9.

The hourly electric demand from ccASHPs is therefore

$$E_i = \begin{cases} 0 & if\ T \geq 65 \\ \dfrac{q_i(65-T)}{COP(T)} & if\ T_c \leq T < 65 \\ \dfrac{q_i(65-T)}{COP(T)} & if\ T < T_c\ \ with\ electric\ backup \\ 0 & if\ T < T_c\ \ with\ fossil\ backup \end{cases}.$$

We assumed that an additional 6% of electricity will be consumed to run the ccASHPs' defrost modes (Walczyk 2017). The total hourly electric space heating load on the system will then be $E = \sum_i w_i E_i$, where w_i represents the weight assigned to the i^{th} RECS building (i.e., the number of other buildings in New England that RECS building i stands in for).

As of 2020, the state of residential building code adoption in New England ranged from 2009 IECC in Connecticut, Rhode Island, New Hampshire, and Maine to 2015 IECC in Massachusetts and 2018 IECC in Vermont (ICC 2020). To approximate the thermal performance of new buildings, we calculated the weighted average of q for the 30 New England RECS buildings constructed between 2000 and 2015. We obtained a value of 324 Btu/hr-HDD. A better apples-to-apples comparison would look at RECS buildings built since 2009, but only six of those were available, so we opted for the larger range to lower statistical uncertainty. In our standard DSM package we assumed new buildings are constructed to IECC 2021 codes, leading to a (conservative) decrease in q of 10% (NBI 2020). In the deep package we assumed envelopes of all new buildings are built to passive house standards, leading to a drop in q of 80% (Passipedia 2020).

ELECTRIC VEHICLES

We assumed that the energy draw of an average light-duty EV in 2040 will be comparable to the top-performing light-duty cars of today. Through a comparison of 24 leading 2019 EV models, we found a best mileage performance of 4.8 miles/kWh (Gorzelany 2019). The average vehicle-miles traveled (VMT) of light-duty vehicles is currently 11,467 miles per year (DOE 2020a). This leads to an average draw of 6.55 kWh per day.

We represented the future heavy-duty vehicle fleet using the current distribution of transit buses and class 8 trucks. Buses and trucks come in different varieties (e.g., city bus, school bus, port drayage, garbage truck), so we assumed that the battery characteristics of today's best-performing EVs in each group will become the average in 2040. This works out to be 0.91 miles per kWh and 0.37 miles per kWh for transit buses and class 8 vehicles, respectively (Gao et al. 2018). We assumed the average bus travels 23,000 miles per year and that the average class 8 truck travels 63,428 miles per year (DOE 2020b).[49] Altogether, this evaluates to an average daily energy draw of 69.3 kWh and 469.2 kWh for buses and class 8 trucks, respectively. We used the numbers of reported buses and class 8 trucks on the road in 2016 to perform a weighted average of these values, consequently arriving at a final average energy draw of heavy-duty vehicles of 384.5 kWh per day (BTS 2021; OOIDA 2021). Drawing from the same sources, we assumed medium-duty EVs will travel 13,000 miles per year at 1.25 miles per kWh for an average energy draw of 28.5 kWh per day per vehicle.

The EFS medium scenario reports 98.3%, 1.6%, and 0.6% of EVs will be light-, medium-, and heavy-duty, respectively. Taking the weighted average, we estimated the average daily energy draw of an EV in 2040 will be 9.15 kWh. We normalized the load shape of an EV in New England on a January weekday as reported by EV infrastructure company ChargePoint with the daily energy draw of 9.15 kWh, then multiplied by the number of EVs in 2040 to derive our base EV load profile (Black 2019).

We recognize that there is a fair amount of uncertainty in these estimates. We are unaware of any studies that project EV load shapes (either managed by utilities or otherwise) and performance in 2040. We acknowledge that a warming climate could affect when and for how long people choose to drive. Battery technologies are expected to evolve. Rideshares, active transportation, and autonomous vehicles may change vehicle miles traveled in unexpected ways, particularly among the younger generations (Shelton Group 2020). Working remotely may reduce the number of daily commutes, a phenomenon we already see emerging from the COVID-19 pandemic. In addition, while much EV charging currently takes place at home, if state policy drives more EV ownership, we may see an increase in midday workplace charging, especially among renters and occupants of buildings without reliable access to off-peak charging, such as multifamily residences.

ELECTROCHEMICAL BATTERY STORAGE

We estimated storage capacity by mapping its relationship to solar PV deployment. We used a power law relationship to extrapolate ISO-NE's regional forecast through 2029 of behind-the-meter solar PV, concluding that there will be about 7,200 MW of solar capacity available in 2040 (ISO New England 2020c). However, New England currently trails a leading solar-plus-storage state, Hawaii, in its ratio of grid-scale storage capacity to total regional PV capacity, achieving just 8% to Hawaii's 23% (EIA 2020c, 2021b). The high penetration of solar energy in Hawaii has led to rate design structures that all but require behind-the-meter PV to be paired with storage to be cost effective. Given New England's ambitious renewable energy targets, we anticipate the region will at least reach Hawaii's ratio of 23% and assume that this number roughly tracks the ratio of expected behind-the-meter storage. We therefore estimated that there will be about 1,650 MW of behind-the-meter electrochemical battery storage installed in New England in 2040.

We assumed that the percentage of this battery capacity available to DR programs will track the percentage of utility customers enrolled in time-varying rates. Only about 4% of customers nationwide are currently subscribed to a TOU or critical peak pricing rate, but

[49] The average annual VMT of transit buses and school buses are reported as 34,012 and 12,000 miles, respectively. We took the average of these two values to represent the bus stock as a whole.

that number is expected to increase to 12% of ratepayers by 2025 (Faruqui 2020). We assumed that this level of adoption will continue and that these rates will reach 36% of customers by 2040 (Hledik et al. 2019).

Utilities like National Grid (Massachusetts) and Green Mountain Power (Vermont) are currently running battery DR pilots, raising the likelihood that programs of this nature will be more ubiquitous in 2040. The National Grid winter peak battery storage pilot study found that on average 72% of ascribed battery capacity was available to be called on for demand response events lasting up to 1.5 hours (National Grid and Unitil 2020). We took this as the upper limit in our deep DSM package, and assumed that half of that would be available for the smart package. We calculated that, taken collectively, 297 MW and 594 MW of flexible battery capacity will be available for load shifting during peaks in our smart and deep DSM packages, respectively.

We also recognize that many customers purchase battery storage as a form of backup power, which can be particularly important as a resilience measure during extreme weather events. It is important, therefore, that any energy discharged to the grid be restored to customers within a reasonable period. We adopted a limit of 12 hours, though in our model our DSM packages were almost always able to restore charge on much shorter time scales.

Appendix B. Regional Analysis — Additional Results

In this appendix we include additional results on load shape and savings profiles resulting from our regional analysis of New England.

100% RESIDENTIAL HEAT PUMPS, STANDARD AND SMART PACKAGES

Figures B1–B4 illustrate the system load savings from our standard and smart DSM packages under the electrification scenario in which 100% of residential heating load in 2040 is met with ccASHPs.

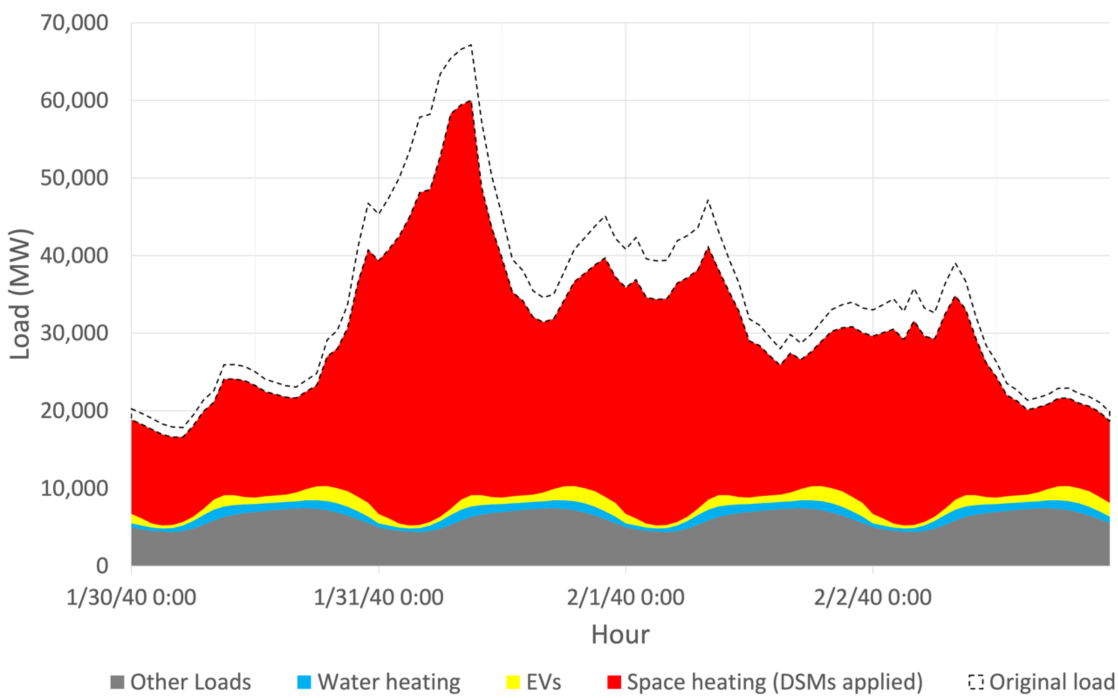

Figure B1. New England load profile during 2040 polar vortex event with 100% of residential heating load met by ccASHPs (electric resistance backup) before and after applying standard DSM package. Industrial and "other" commercial loads not included.

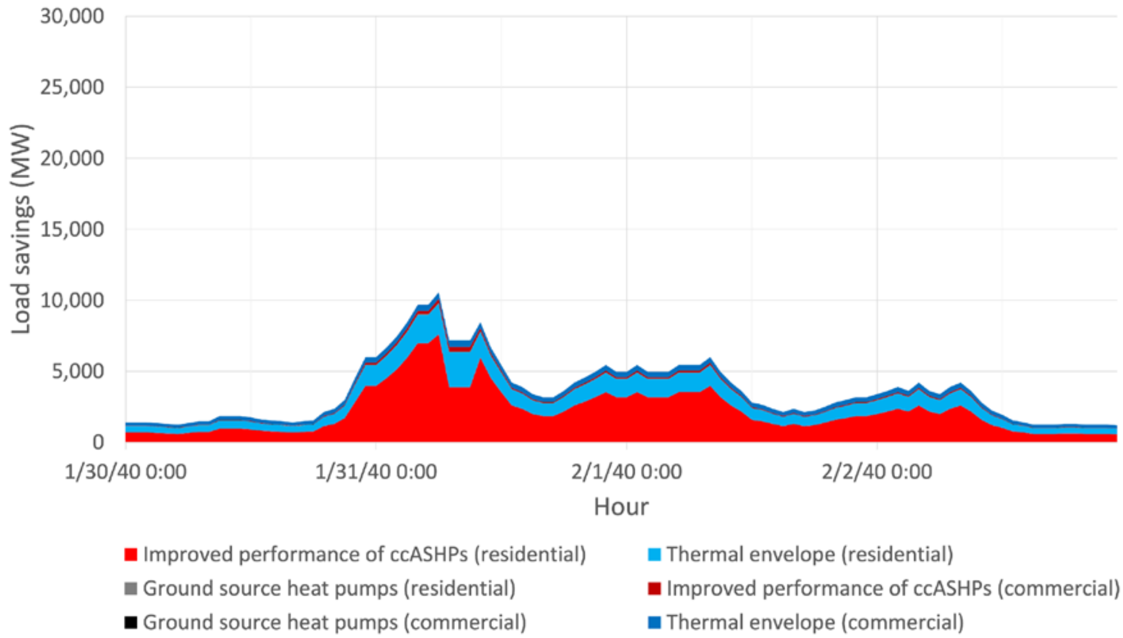

Figure B2. Load savings from figure B1 provided by each measure in the standard DSM package

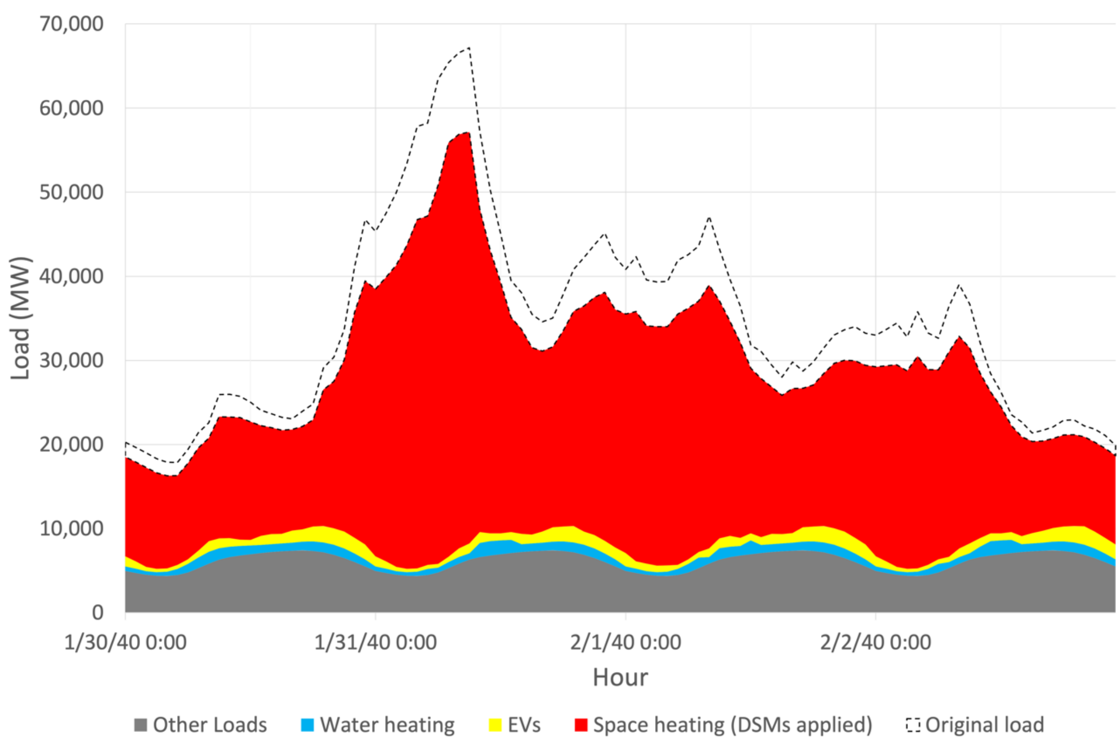

Figure B3. New England load profile during 2040 polar vortex event with 100% of residential heating load met by ccASHPs (electric resistance backup) before and after applying smart DSM package. Industrial and "other" commercial loads not included.

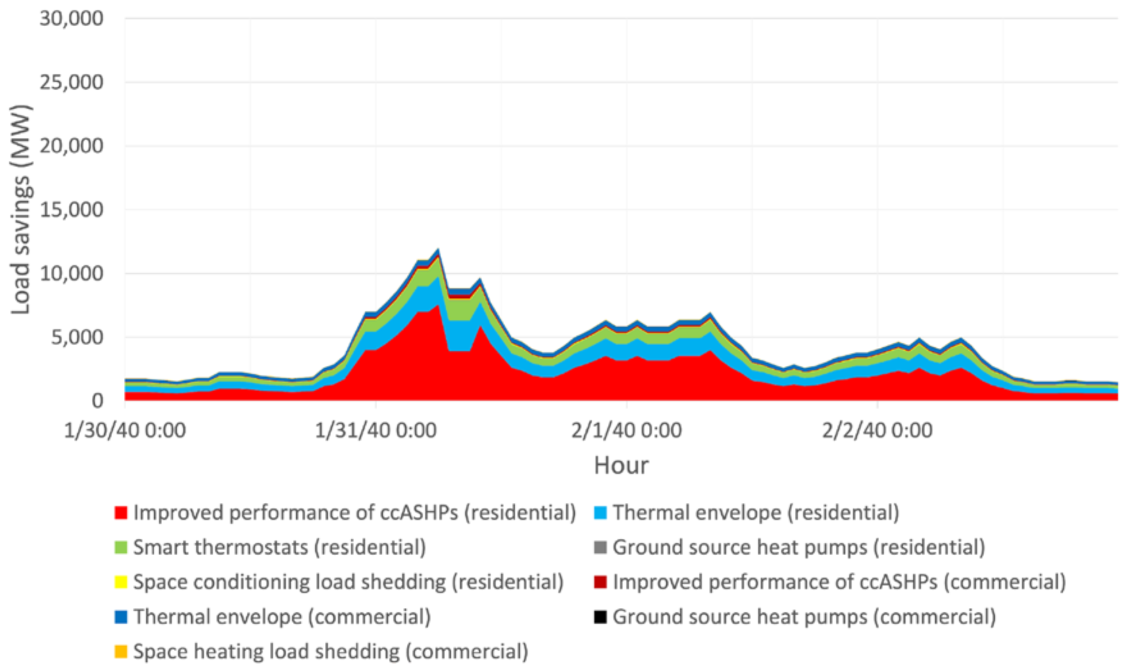

Figure B4. Load savings from figure B3 provided by each measure in the smart DSM package

FOSSIL BACKUP CASE

Figures B5–B12 illustrate the system load shapes and savings from select standard, smart, and deep DSM packages.

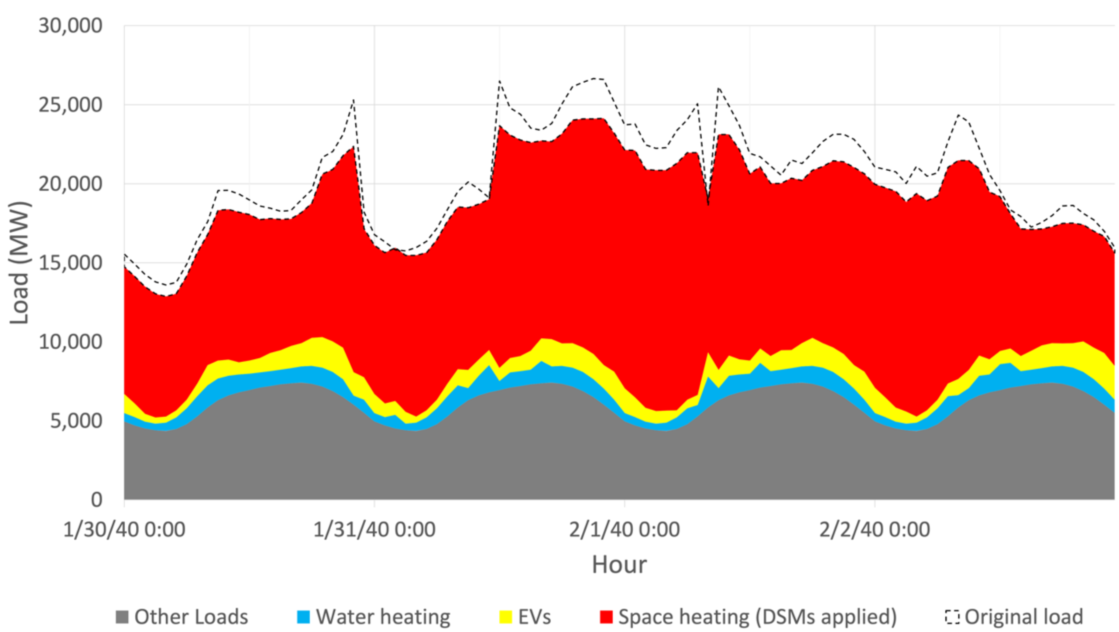

Figure B5. New England load profile during 2040 polar vortex event with 1.46 million residential heat pumps installed (fossil backup at 0°F) before and after applying smart DSM package. Industrial and "other" commercial loads not included.

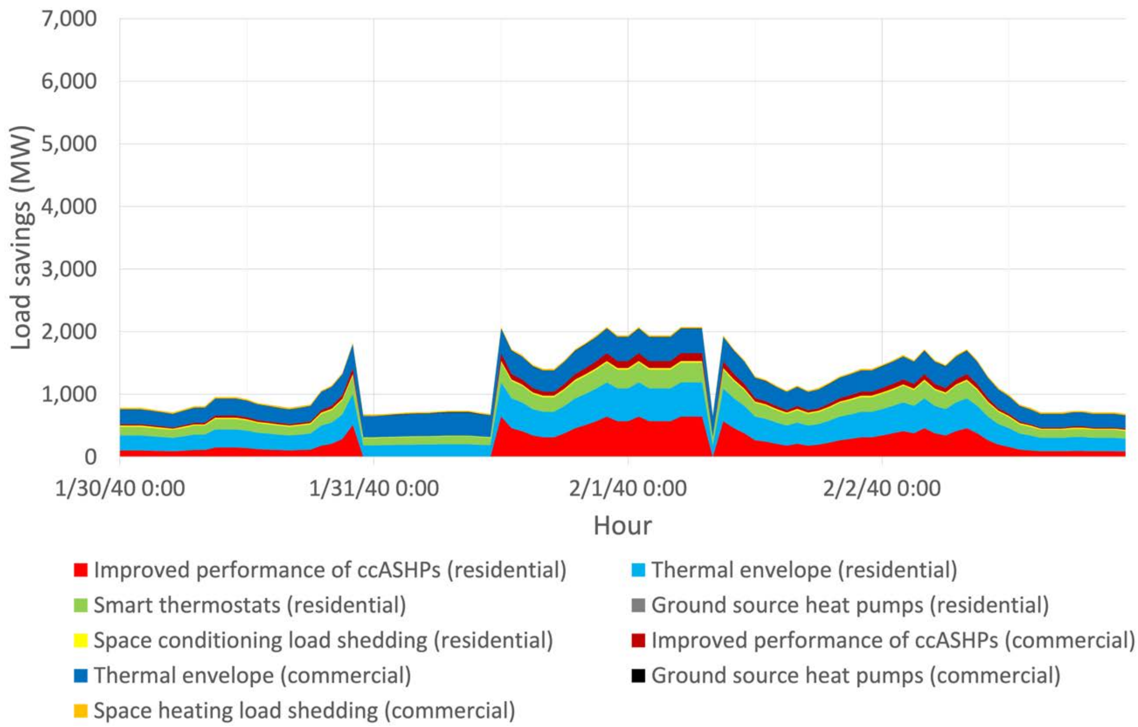

Figure B6. Load savings from figure B5 provided by each measure in the smart DSM package

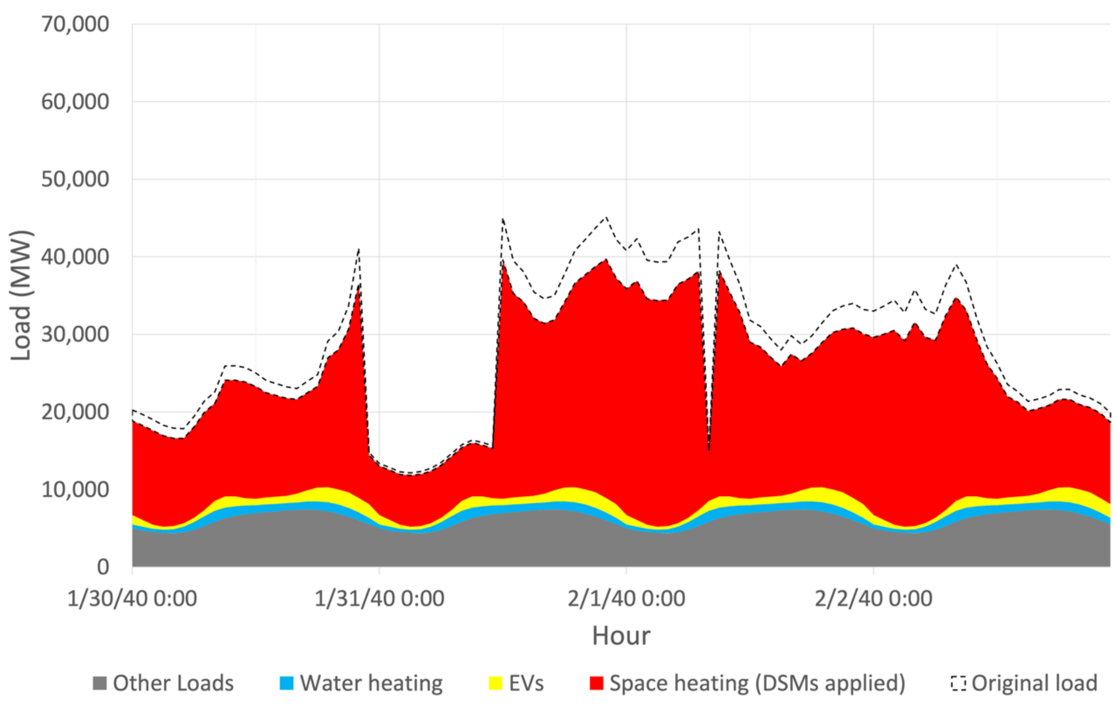

Figure B7. New England load profile during 2040 polar vortex event with <u>100% of residential heating load met by ccASHPs</u> (fossil backup at 0°F) before and after applying <u>standard DSM package</u>. Industrial and "other" commercial loads not included.

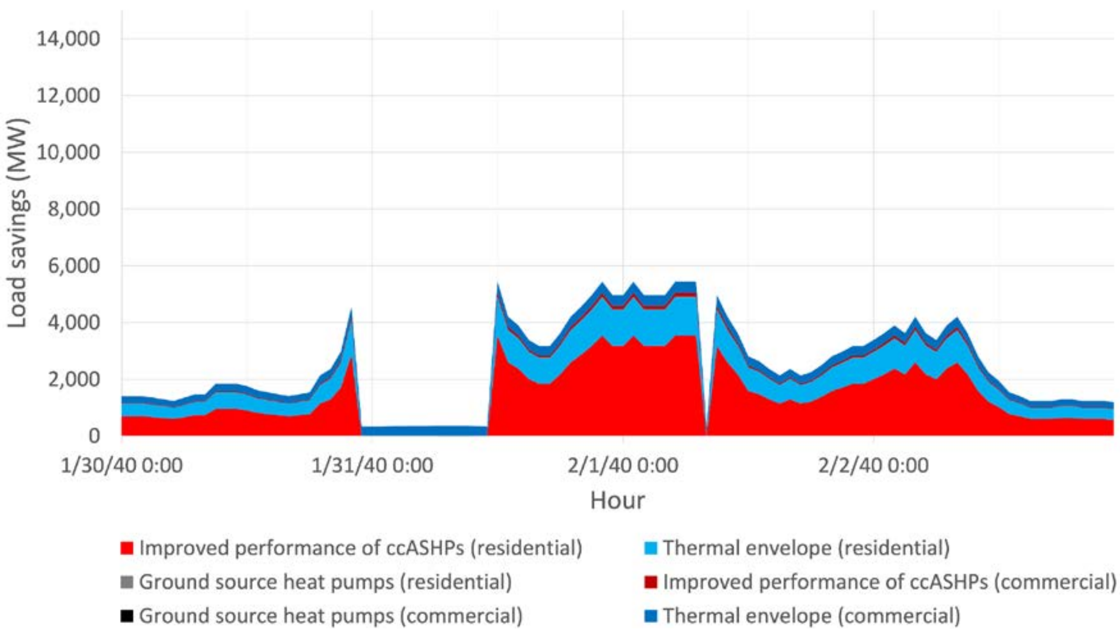

Figure B8. Load savings from figure B7 provided by each measure in the standard DSM package

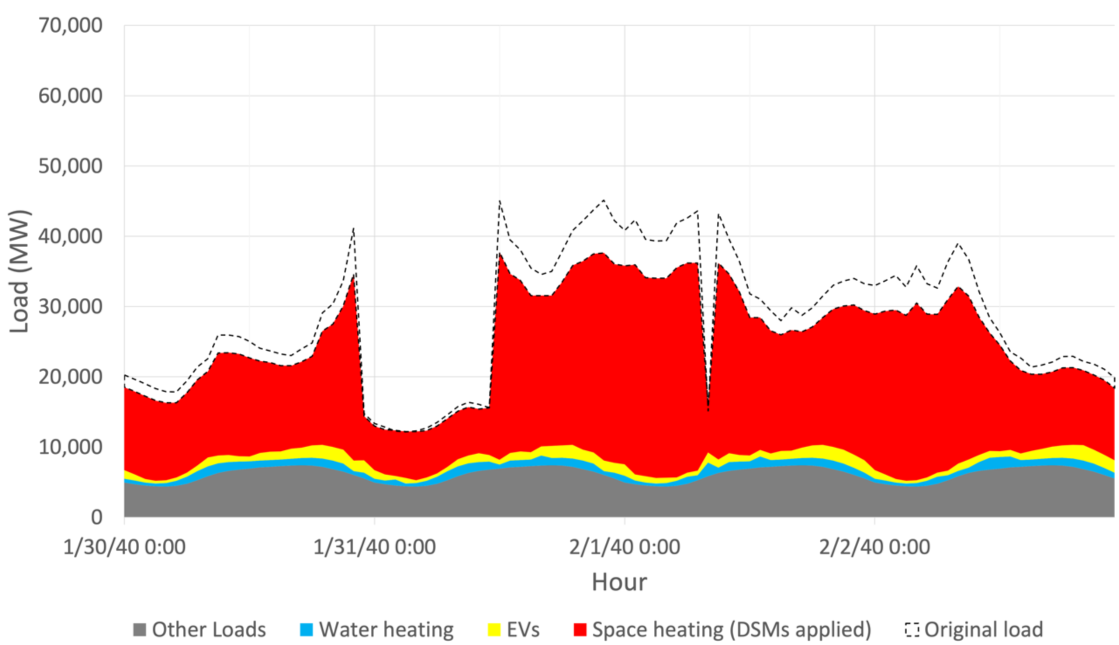

Figure B9. New England load profile during 2040 polar vortex event with <u>100% of residential heating load met by ccASHPs</u> (fossil backup at 0°F) before and after applying <u>smart DSM package</u>. Industrial and "other" commercial loads not included.

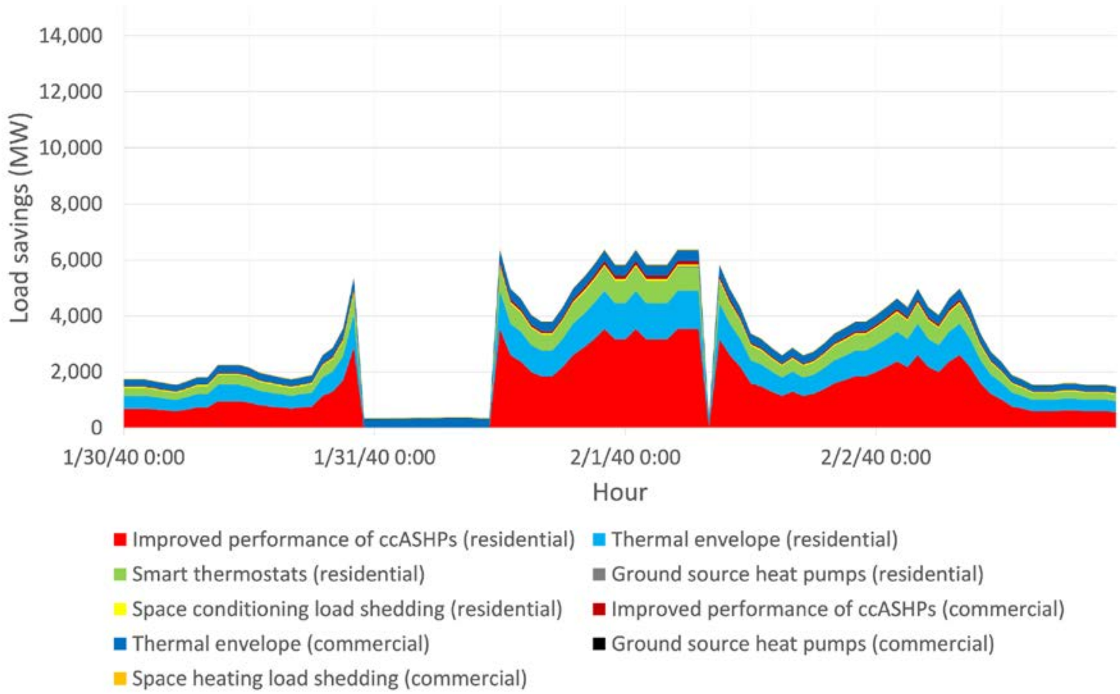

Figure B10. Load savings from figure B9 provided by each measure in the smart DSM package

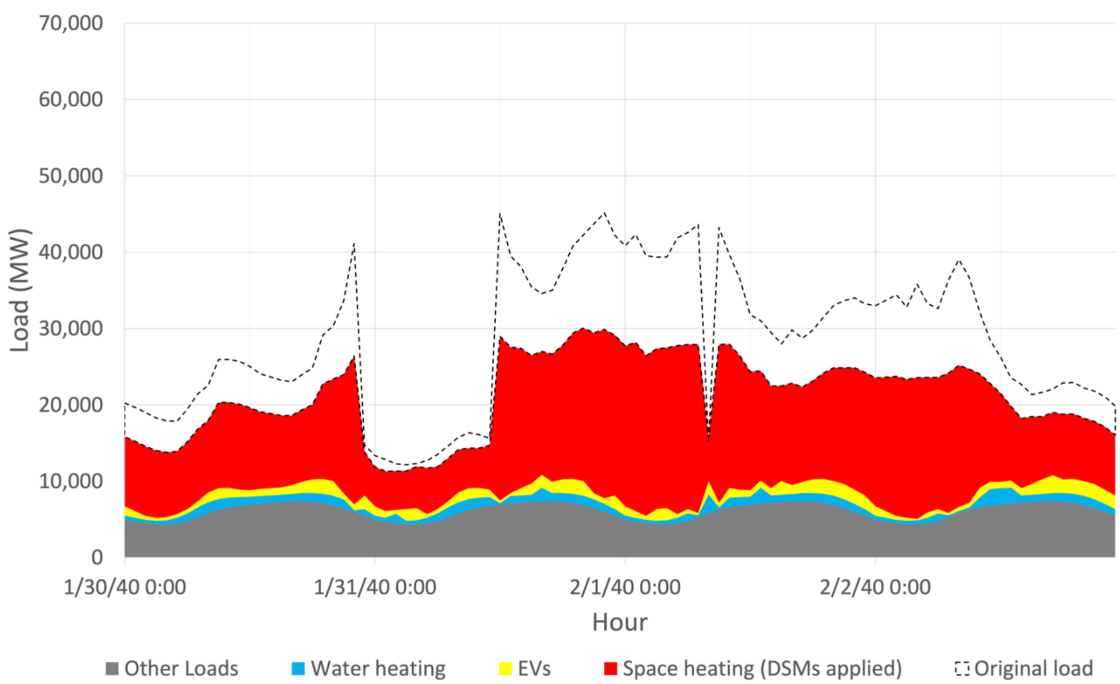

Figure B11. New England load profile during 2040 polar vortex event with <u>100% of residential heating load met by ccASHPs</u> (fossil backup at 0°F) before and after applying <u>deep DSM package</u>. Industrial and "other" commercial loads not included.

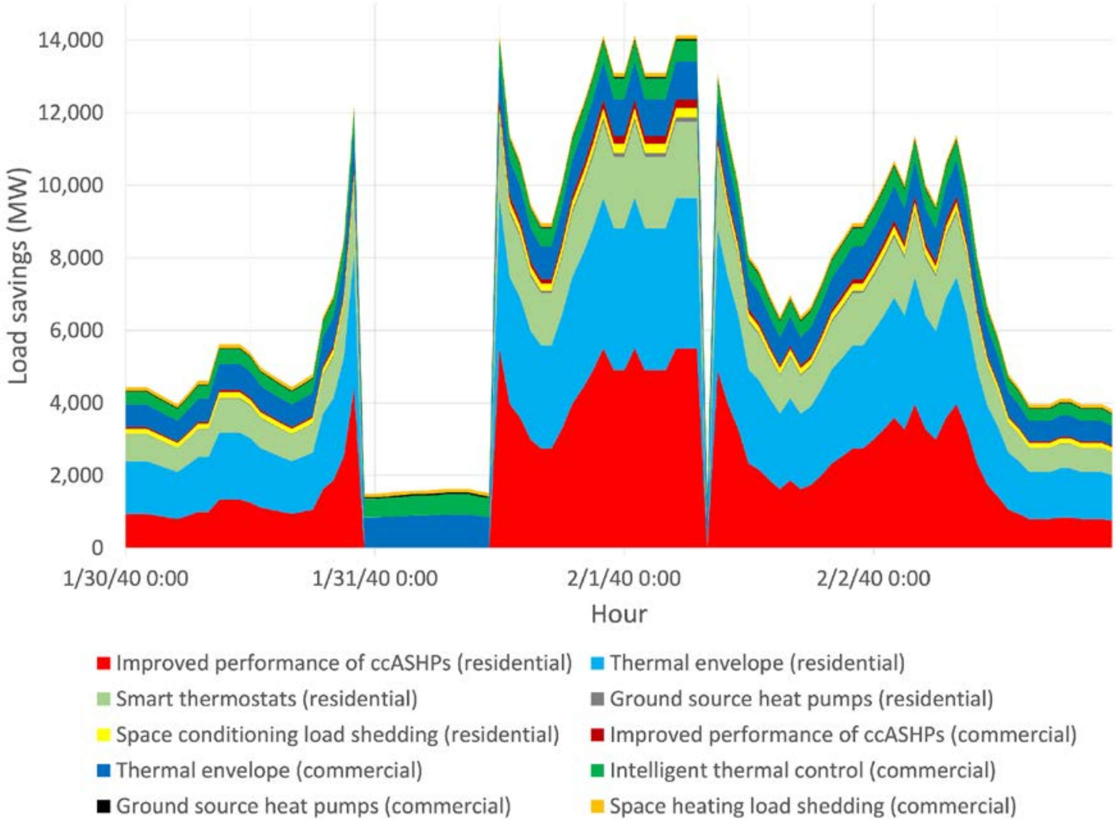

Figure B12. Load savings from figure B11 provided by each measure in the deep DSM package

Appendix C. Cost Analysis Inputs and Methodology

To determine wholesale cost estimates for the analysis as displayed in figure 22, we developed a weighted average cost of wholesale energy ($/kWh) among the New England states using Synapse's AESC User Interface tool. This weighted average derived from states' relative MWh consumption in 2018, with the biggest consumer being Massachusetts (~45%) and the smallest Vermont (~5%). We used data from both the Main 2018 AESC and the High Load User Interface to create averages for the main AESC and high load sensitivities, respectively.

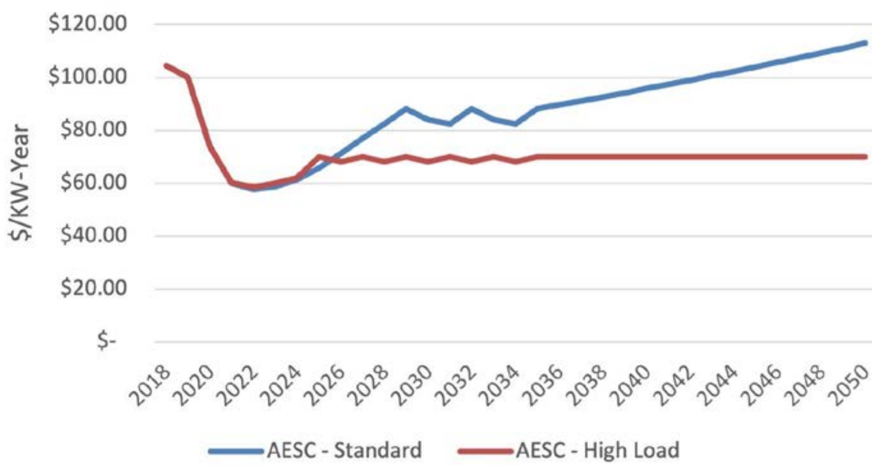

Figure C1. ISO-NE capacity prices. *Source:* Knight et al. 2018.

Capacity costs shown in figure C1 are the same across ISO-NE, so a weighted average of each state was not necessary. An unexpected result from the forecast data was that the high load scenario came with lower capacity costs than the main AESC scenario. The primary difference between the two scenarios is the addition of load from heat pumps and EVs to the grid system, shown in figure C2. Levelized cost of capacity is around $73/kW over the next 10 years and is estimated at $75–85 over the next 15–20 years. (As with all levelized cost calculations, future year values are discounted back to the net present value.)

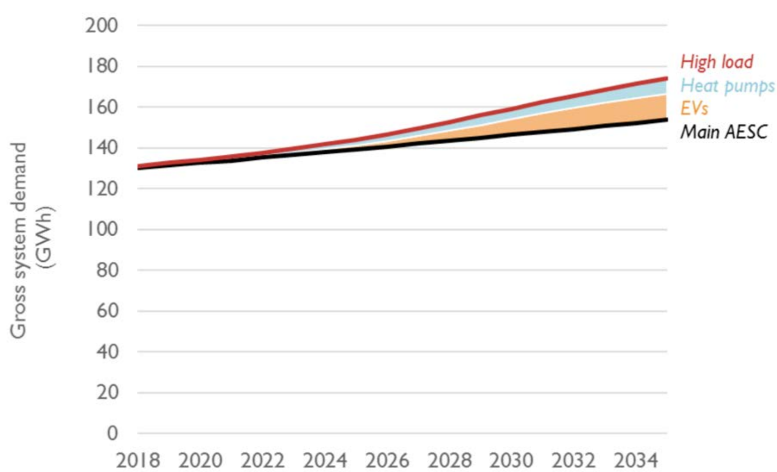

Figure C2. Inputs for Synapse AESC high electrification scenario. *Source:* Knight et al. 2018.

Additional values that were available in the user interface but were not factored into the data represented in figures C1 and C2 include:

- Demand reduction induced price effects (DRIPE) for energy and capacity ($/kWh and $/kW)
- Reserve margins (%)
- Renewable Energy Certificate (REC) costs ($/kWh)
- Non-embedded costs ($/kWh)
- T&D costs ($/kW)
- Reliability costs ($/kW)

DEMAND-SIDE MEASURE COSTS

The costs represented above are program administrator costs of saved energy and peak demand based largely on research from Lawrence Berkeley National Laboratory (LBNL) that aggregates data from a nationwide sample of demand-side programs. The categories used in the LBNL study differ slightly from the categories of demand-side measures evaluated in this analysis; the source of data for each is described in the "Source" column of table C1. For ground-source heat pumps, since no equivalent aggregate exists in LBNL's program dataset, we compiled our own estimate based on program administrator costs represented in ACEEE research (Nadel 2020). An analysis of ground-source heat pump incentives found that program administrator costs for this type of program is on average 106% higher than for air source heat pump programs.

Table C1. Levelized costs of demand-side measures

Demand-side measure	Levelized cost of saving electricity ($/kWh)	Levelized cost of saved peak demand ($/kW)	Source
Cold-climate air source heat pumps	$0.036	$170	LBNL "Residential HVAC" programs meta-analysis
Weatherization/ thermal envelope	$0.0475	$262	LBNL "Whole-Home Retrofit" programs meta-analysis
Deep retrofits	$0.1344	No data	LBNL "Deep Energy Retrofit" meta-analysis
Smart thermostats (residential)	$0.046	$262	LBNL "Residential Behavioral" programs meta-analysis
Smart thermostats/ thermal management (commercial)	$0.019	$107	LBNL "C&I Custom Rebate" programs meta-analysis
Ground-source heat pumps	$0.075	$354	ACEEE heat pump programs analysis

Sources: Nadel 2020; Frick et al. 2020; Less and Walker 2014

The load savings resulting from the DSMs we identify as being important for reducing winter peak can be realized year-round or exclusively during the winter peak period. For example, ccASHPs reduce both heating and cooling loads and therefore confer benefits in both the winter and summer, while demand response measures are likely to be called upon only during periods of very high system load. To identify the fraction of load shaping, shedding, and shifting benefits that accrue exclusively during the winter peak period, we considered how each DSM will actualize during the top 100 winter-peaking hours of 2040.

Six of the seven demand-side measures that deliver year-round savings are specifically designed to reduce heating and cooling loads.[50] We roughly estimate that the percentage of those DSM benefits that fall during a winter peak in 2040 will equal the ratio of heating degree days during the top 100 system load hours to the sum of the heating and cooling degree days over the course of the year. We let the hourly temperatures in Worcester, Massachusetts, in 2019 serve as a proxy for those in 2040, and assume that the largest system loads will occur during the 100 coldest hours.[51] Those 100 coldest hours equate to about 112 heating degree days out of the approximately 7.500 heating and cooling degree days across all of 2019 (National Centers for Environmental Information 2020). We consequently estimate that 112/7,500 = 1.5% of the DSM program benefits fall during the winter peak.

The seventh DSM that we anticipate will deliver year-round savings is managed EV charging. We expect the load savings will accrue equally throughout the year, for a benefit of 100 super-peak hours/8,760 hours in a year = 1.15% accruing during winter peaks.[52]

The remaining DSMs (battery DR, water heating DR, and temperature set-point reductions) will likely be applied throughout the year to help manage loads and take advantage of TOU rates, but we conservatively estimate that they will be utilized only during the top 100 system peak hours, meaning that 100% of their program benefits will accrue during winter peaks.

[50] These are ccASHPs, ground-source heat pumps, weatherization, deep thermal retrofits, intelligent thermal management (residential), and intelligent thermal management (commercial).

[51] For comparison, 49 of the 100 hottest hours in 2019 fell within the 100 highest system load hours in ISO-NE (ISO New England 2020b).

[52] This percentage is likely to be a bit higher in reality as batteries discharge more quickly at lower temperatures.

Appendix D. Winter Peaks Program Survey

Winter Peaks Program Questions

1. **Your Contact Information**

    a) First and Last Name

    b) Email address

    c) Phone number

    d) Employer/Organization

2. **Utility and Program Name**

    a) Please select the grid region. If the program takes place across multiple regions, indicate which region the majority of savings occur.

    - CA-ISO (California ISO)
    - Pacific Northwest
    - MISO (Midcontinent ISO)
    - ISO-NY (ISO — New York)
    - ERCOT (Electric Reliability Council of Texas)
    - SPP (Southwest Power Pool)
    - Southeast
    - PJM
    - ISO-NE (ISO New England)
    - Other U.S. Grid Region
    - Outside the United States

    b) Name of utility

    c) What is the name of the EE or DR program?

    d) If available, please provide a URL for more information about the program.

3. **Program Description and Categories**

    a) Please provide a short description of the program's design, implementation, and stakeholders involved in these processes.

    b) Please provide a description of the program's goals (e.g. peak demand reduction, demand flexibility, customer satisfaction, public health, renewable energy portfolio standard, etc.).

    c) What year did the program begin? (If the program has not yet launched, please put the approximate start date.)

d) Is the program still in operation?

- Yes
- No
- Not sure
- Program has not started yet

e) Please select the sectors the program targets: (choose all that apply)

- o Residential
- o Commercial
- o Industrial
- o Transportation
- o Municipal government operations
- o Other: ________

f) Does the program include any of the following: (choose all that apply)

- o Weatherization
- o Appliance Replacements/Retrofits
- o Energy Audits
- o Smart Thermostats
- o Distributed Energy Storage
- o EV Charging
- o Time-Based Utility Rates
- o Focus on Low-Income Communities
- o Strategic Energy Management (SEM)

4. **Program Delivery and Partnerships**

a) Which utilities or third-party implementers are responsible for the design or administration of the program?

b) Does the program involve partnerships with any other entities (e.g., government, nonprofit) on the design and/or implementation of the program?

- Yes
- No

If yes, please list the other organizations involved in the design and/or implementation of the program and a description of the partnership, if possible.

c) Who provides funding for this program?

d) What is the program's budget? (indicate if total or annual)

e) Is this program part of a larger initiative/program/campaign?

- Yes, part of a larger initiative
- No, this program is independent
- Not sure

If yes, please describe the larger initiative that includes this demand-reduction program.

5. **Program Evaluation and Impact**

a) Has the program been evaluated to measure its impact and progress toward its goals?

- Yes
- No

If yes, please provide information about the evaluation and measured impact, including MW savings

If no, have program implementers tracked program progress for some predefined key metrics? If so, please describe.

6. **If available, please upload a program evaluation or any other program documentation.**

7. **Survey Followup**

Are you willing to be contacted to provide additional information about the program described above?

- Yes, you can contact me for more information
- No, but I can direct you to a contact to provide more information
- No, please do not contact me for more information

Thank You!