

System impacts of decarbonization pathways for space heating in cold climates

Final Project Report

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Motivation and objectives

Declining costs of variable renewable energy (VRE) and policy support are motivating energy consumers to displace their use of fossil fuels with cleaner electricity consumption. This trend is most evident in the adoption of electrical vehicles (EVs) in transportation and heat pumps (HPs) in the building sector. For example, in the U.S., the share of EVs in total sales has more than tripled from 2.4% in 2020 to 7.8% in 2022, global sales of HPs grew by 11% in 2022 and notably exceeded sales of gas furnaces (International Energy Agency n.d.; n.d.). While electrification is broadly recognized as a key element of economy-wide decarbonization, to be successful, it requires simultaneously decarbonizing and expanding the electric power sector in a cost-effective manner.

In this context, building heat electrification introduces several challenges that warrant further analyses. **First**, in the US context, electrifying buildings is expected to reduce natural gas (NG) consumption for heating. Since buildings are major NG consumers today, electrification will impact the economic viability of NG transmission infrastructure and thus potentially impact the availability of NG for the electric power sector. Consequently, efforts on building decarbonization need to be coordinated with gas-electric infrastructure planning. Such an end-to-end coordination will facilitate timely deployment of long-lead-time, low-carbon energy infrastructure and also support gradually reducing operating costs of legacy NG infrastructure through strategic retirements.

Second, expanded building electrification could increase weather-sensitivity of electricity consumption and thus introduce significant seasonal and interannual fluctuations in electricity demand. For instance, large-scale building electrification in cold climates like the U.S. Northeast could result in the region's electricity system transitioning from a summer to winter peaking system (Waite and Modi 2020; Williams et al. 2021).

Third, unlike transportation electrification, electricity consumption for heating is likely to have limited flexibility, thereby highlighting the importance of demand-side technology and policy measures to mitigate increases in peak demand with electrification.

Fourth, the heterogeneity in the existing building stock implies that fuel switching will have spatially differentiated cost impacts, thus warranting spatially and temporally resolved analysis of building electrification impacts.

The goal of this project is to evaluate the demand-side impacts of electrification-based decarbonization of buildings and the necessary transformation of current power-gas systems to accommodate this new demand under deep decarbonization scenarios. Our analysis applies a suite of modeling approaches, described below, to the case study of the New England region, where NG plays a dominant role today both for power generation and building heating.

Research questions

Our project aims to address several key gaps in the literature regarding the system impacts of electrification-based decarbonization of buildings in cold climates. First, while several research studies have investigated the supply-side implications of deeply decarbonizing regional and national electricity systems, the demand-side analysis and its resulting power system impacts have received relatively less

attention. In particular, the spatio-temporal characterization of electricity and NG demand from buildings, considering the heterogeneity in the building stock, as well as the effect of various technology and policy interventions, remain key areas for further research. Second, there is a limited number of studies on bulk power system decarbonization that also consider the coordination with NG infrastructure (Von Wald et al. 2022; Wu et al. 2022), whose reduced relevance for heating might also impact its role in the grid. Moreover, these studies have a limited appreciation of weather factors that can crucially impact the load projections as well as power-gas system outcomes. Third, electrification will also impact electricity distribution networks, where further analysis is needed to understand how the need for network reinforcements is affected by network topology, retail tariff design, as well as adoption of distributed energy resources (DERs) (Deetjen, Walsh, and Vaishnav 2021; White et al. 2021; Protopapadaki and Saelens 2017).

Here, we propose to address the following research questions spanning both the bulk energy system and distribution system (Figure 1), needing further study identified above.

- What are the plausible spatio-temporal variations in electricity and NG demand from space heating resulting from different rates of heat electrification, climate and weather patterns, and technology adoption scenarios?
- What are the distribution network impacts of different heat electrification levels and how can DERs play a role in mitigating impacts? How do these impacts influence electricity tariff design, and conversely, how does electricity tariff design influence customer load shapes?
- What are the bulk energy system impacts (e.g., wholesale power costs, investment needs) of expanded heat electrification under different scenarios defined by degree of heat electrification, building energy efficiency (e.g., envelope improvements), emissions constraints, and technology scenarios?
- How do inter-annual variations in supply and demand and the availability of emerging technologies (e.g., long-term storage or low-carbon fuels) impact system outcomes?

Data and methods

Figure 1 broadly summarizes the multi-faceted analytical approach used in this study, which includes: a) a bottom-up model for demand-side characterization in a spatially and temporally resolved manner; b) a coordinated electricity-gas infrastructure planning model that co-optimizes investments and operation across both systems while considering technology, network operating constraints and policy constraints (e.g., emissions targets); c) an end-user demand optimization model that minimizes customer bills subject to end-use technology and building-level constraints under various retail rates and demand-side scenarios; and d) a distribution network planning model that minimizes operation and planning costs while adhering to technical constraints (i.e., thermal and voltage limits and topological constraints). These models and accompanying data sets are described in further detail below.

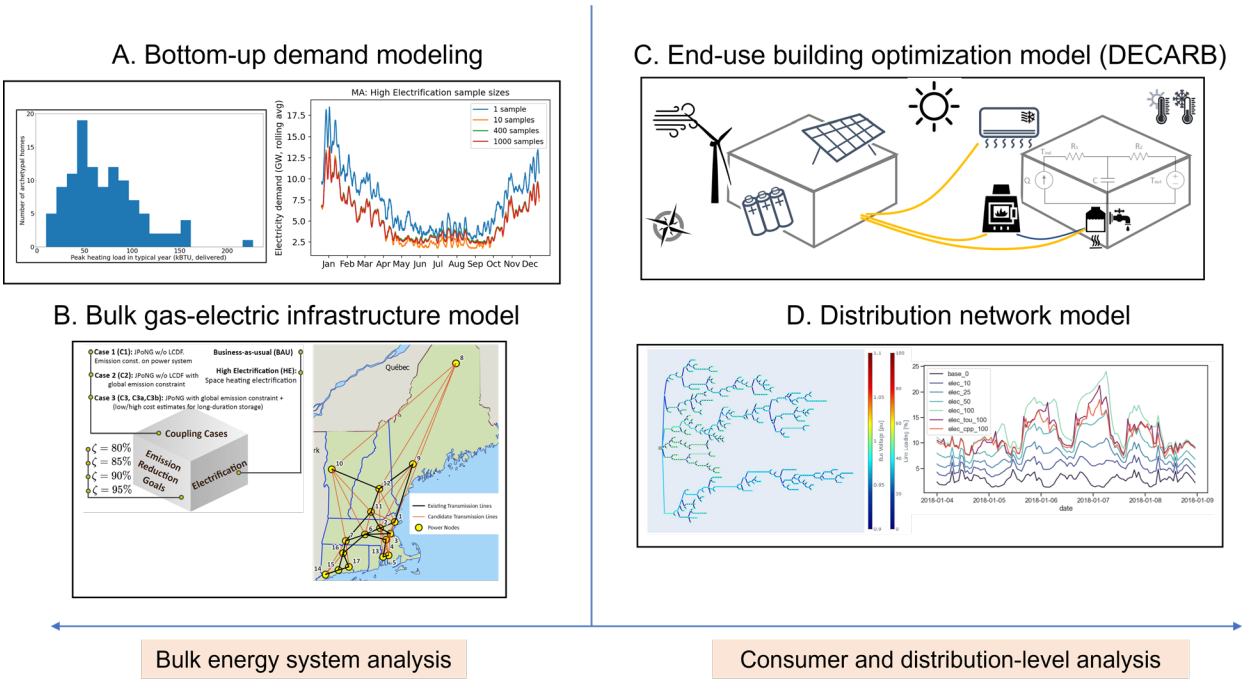


Figure 1. Overview of modeling approaches developed and employed in the study, spanning the two levels of analysis.

Regional-level demand characterization

Residential heating electrification demand modeling

We leverage a bottom-up building energy modeling framework to evaluate regional hourly demand impacts across New England. The bottom-up modeling approach, summarized in Figure 2, enables characterization of the diversity of the housing stock through simulation of many representative building archetypes sourced from NREL's ResStock model (Wilson et al. 2022) and does not require historical consumption data as an input.

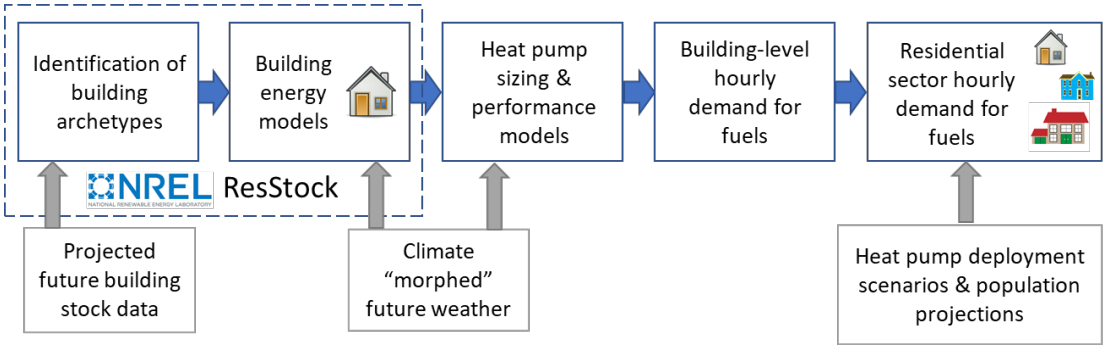


Figure 2. Overview of bottom-up modeling framework of energy demand from buildings

For a given input dataset of housing stock and hourly weather features, ResStock generates hourly energy demand outputs that mutually account for diversity in building stock, occupant behavior, and end-use

technologies. We generate a set of buildings that contain several thousand archetypes reflecting the projected regional building stock in 2050. To approximate a broad range of realistic weather patterns for 2050, we use spatially resolved 20 years of historical weather data spanning the years 2001 to 2020 for the New England region (see Figure 2). We then employ the so-called *morphing method* to account for the projected impact of climate change by 2050. The morphing method is common in the building energy modeling literature (Belcher, Hacker, and Powell 2005) and leverages monthly future climate projections to alter the historical hourly weather patterns and approximate the effects of climate change while preserving realistic weather phenomena.

To capture the effect of heating electrification for each weather year, we take the hourly heating and cooling demands from each archetype simulated in ResStock and input them to an HP model regressed upon the well-known NEEP cold-climate HP dataset (Northeast Energy Efficiency Partnerships n.d.). The model accounts for the fact that HP heating efficiency and capacity both decline with decreasing ambient temperatures. We calculate the demand impacts for each archetype under two forms of HP sizing strategies commonly considered among stakeholders: 1) a "whole-home" sizing strategy where HPs are "winter-sized" to meet heating needs throughout the year, and 2) a "summer-sized" strategy where a lower-capacity HP is installed (sized for maximum cooling load in the summer) and supplemented in the winter by the home's existing heating system, which most often uses some kind of fuel (typically NG or fuel oil) in a so-called "hybrid" configuration. In both cases, the HP also supplies air conditioning.

We define a set of technology adoption scenarios to capture potential future demand impacts under electrification, as shown in Figure 3 below. The scenarios include a reference (RF) scenario to reflect business-as-usual HP adoption rates and medium and high electrification scenarios with (MX, HX) and without (ME, HE) basic building envelope improvements that make the buildings more thermally efficient. The RF scenario is taken from NREL's Electrification Futures Study (Mai et al. 2018) and all other scenarios are parameterized to reflect a subset of Massachusetts' HP adoption scenarios presented in the Clean Energy and Climate Plan for 2050 (Massachusetts Department of Energy Resources 2022). We focus on air-source heat pumps (ASHP) over other HP technologies because they are most emphasized in the current literature (Waite and Modi 2020; Deetjen, Walsh, and Vaishnav 2021) and adoption projections (e.g., the Massachusetts Clean Energy and Climate Plan for 2050 presumes only 6% ground-source heat pump (GSHP) adoption by mid-century in its "high electrification" scenario).

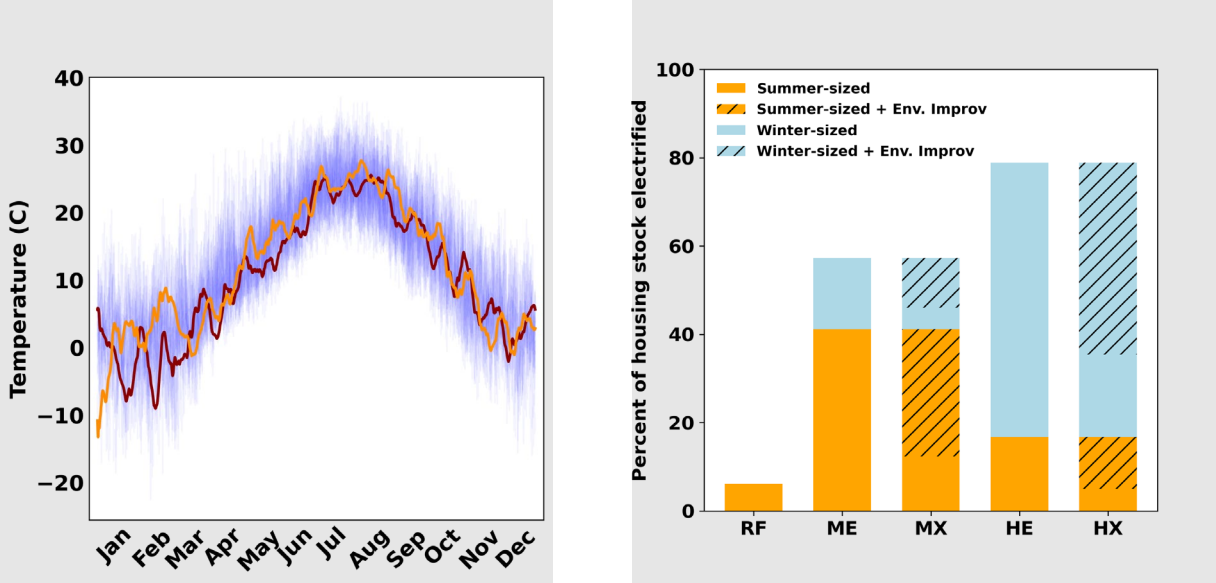


Figure 3. Left: Temperature profiles in Suffolk County, MA for the 20 weather years used in the analysis. Light blue lines in the background illustrate hourly temperature values for all 20 years. Orange and red bolded lines show weekly rolling averages of temperatures for two example years to illustrate the weather diversity. Right: Scenarios for electrification (i.e., HP adoption) of residential building heating for 2050. Shaded bars represent percent of electrified homes also receiving energy efficiency improvements.

Bulk energy infrastructure planning modeling

We formulate an optimization model for joint planning of bulk (transmission-level) power and NG infrastructure with resolved representation of spatial, temporal, and technological system operations. The formulation models the interaction between power and NG networks in deeply decarbonized regional-scale energy systems and provides a systematic evaluation of decarbonization pathways under plausible technology, demand, and policy scenarios. The formulated model accounts for the different temporal granularity requirements for both networks, alternative supply-side technologies including renewable generators (VRE and hydro), short- and long-duration battery storage, low-carbon fuels (LCF) as a substitute for NG, gas generation with and without carbon capture and storage (CCS), transmission expansion, and strategic retirement of NG pipelines. The model is a semi-isolated energy system where only the import of power and NG is possible, and its fidelity includes: i) network constraints for electricity (DC-OPF) and gas (simplified energy flow limits formulation without modeling gas pressures); ii) hourly and daily operations of electricity and NG system including the supply-side balancing operations, respectively; iii) capacity reserve margin for electricity system; iv) availability of resources, like VRE and Canadian hydropower imports; and v) system-wide emissions reduction goals.

We use the supply and demand projections from the method described in an earlier section, 'Residential heating electrification demand modeling,' and apply the integrated optimization model for joint planning of power and NG infrastructure to a case study of the U.S. New England region, as depicted in Figure 4. The bottom-up model projects the power/gas demand as well as availability factors for renewables for the year 2050 under various electrification and weather years. Using the projected values, the planning

model, JPoNG, provides investment and operational outcomes for each unique instance of weather year and electrification scenario.

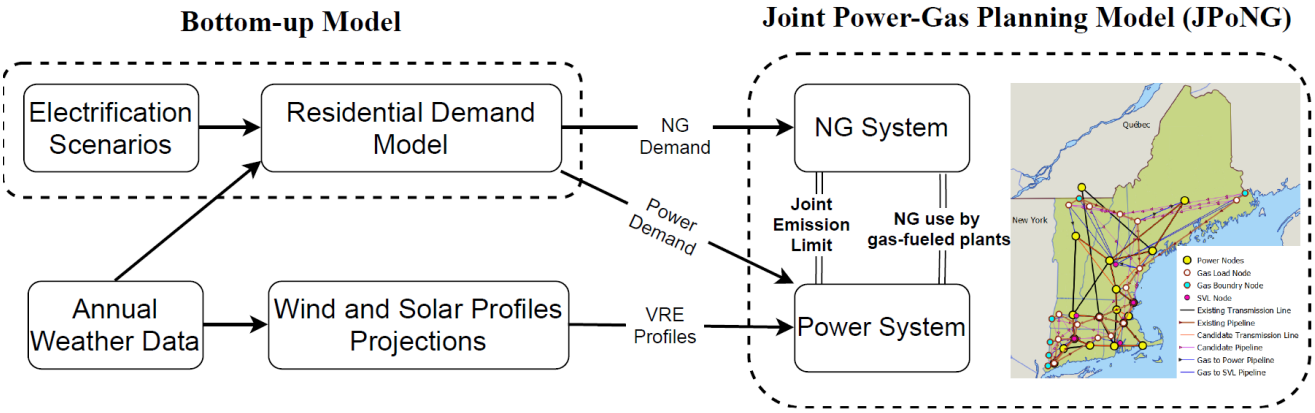


Figure 4: Overview of the modeling framework to evaluate the impact of residential heating electrification on bulk power-gas planning outcomes.

End user and distribution network modeling

End user energy cost optimization

In addition to the bulk system analysis above, we assess the distribution-level impacts of heating electrification under heterogeneous consumer decisions using the DECARB (Distributed Energy Consumption in Actively Responsive Buildings) model, which is an optimization tool designed to simulate the household-level investment and operation of building energy resources. It uses such inputs as hourly building-level load profiles, energy prices, weather data, and technology parameters to optimize the investment and operation of a building's energy resources. The model aims to maintain indoor temperatures within a given range, reflecting occupant comfort and such other factors as thermostat settings and smart thermostat responses to variable rates or weather conditions. The objective is to minimize net present costs associated with different tariff structures including flat, real time, time of use, or capacity peak pricing.

The model assumes rational, price-elastic consumers with perfect foresight of future system conditions, implying that all buildings on the network have advanced meter infrastructure and smart thermostats for automated demand flexibility. We employ the DECARB optimization model to calculate the specific costs of electrification for space conditioning across different types of buildings sampled from a large database of ResStock results produced in NREL's End-Use Load Profiles Project (EULP) (Wilson et al. 2022). The model optimizes the operation of existing installed heating and cooling equipment, which allows us to estimate heating demand and subsequently optimize investment and operation of new heating and cooling appliances.

As a case study of the New England region distribution networks, we randomly sample 100 synthetic buildings in a suburban feeder from the EULP database. The EULP database provided detailed building-level energy consumption variables and construction features, which were instrumental in our cost modeling and optimization.

Simulation of distribution-level gas and power flows

We formulate an integrated gas-electricity operational model to simulate the interactions between power and gas systems at the distribution level, with a particular emphasis on the effects of increased electricity consumption and the blending of different gaseous energy carriers that can serve as low-carbon substitutes for NG. For the electrical power systems, the model uses steady-state AC power flow calculations to determine the system's state, including voltage stability and capacity congestions for transformers and wires. In the context of NGs systems, the model operates under a steady-state assumption, where the state of the gas system is described by the pressure and calorific value at each node.

Our methodology features the use of Synthetic Models for Advanced, Realistic Testing: Distribution Systems and Scenarios (SMART-DS) databases for networks. We utilize these databases to select a representative medium voltage (MV) substation and feeder from a synthetic network that mirrors the San Francisco Bay Area, under the assumption that the network topology and primary characteristics of distribution systems in the US are similar across different regions, with variations primarily in load profiles. This selected sub-network is then adapted to represent a New England suburban distribution network by substituting the load and generation profiles from previously sampled building level data from the EULP database for suburban Boston.

Key results and takeaway messages

Electricity and gas demand impacts

Implications for annual power and gas demand

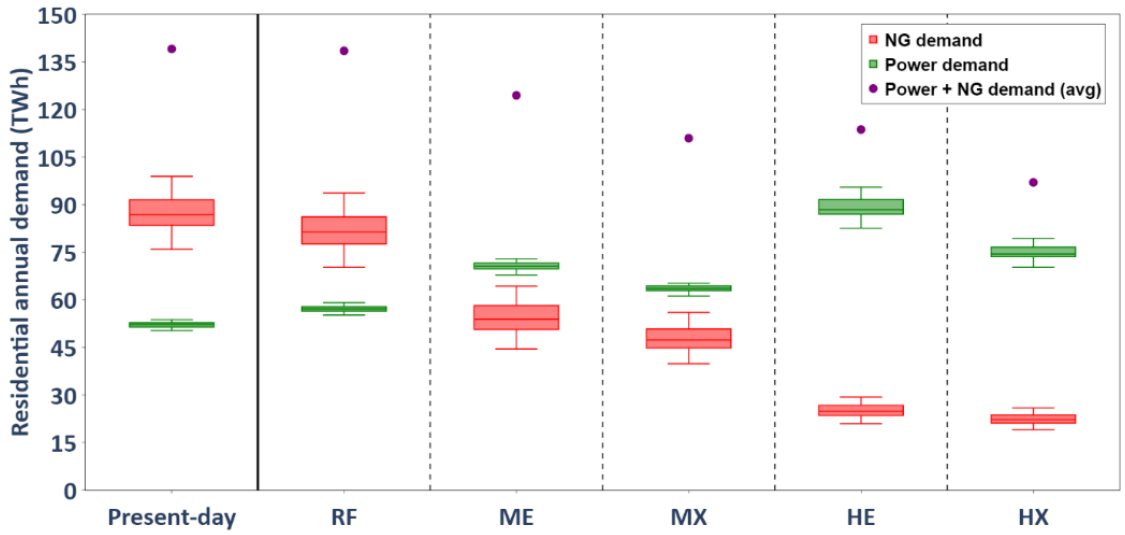


Figure 5. Total annual electricity and gas demands in the residential sector under different electrification scenarios. Each box plot contains demand data for the 20 weather years. HE, HX, ME, MX, and RF are all 2050 scenarios while the "present-day" results are parameterized to approximate 2020 demand conditions. See Figure 3 for scenario details.

With increasing amounts of heating electrification in the housing stock, Figure 5 shows that annual residential NG consumption declines while electricity consumption increases. For the HE and ME scenarios, electricity demand increases over the present day by an average of 36.7 TWh (70%) and 18.5 TWh (35%) across all weather years. The impact of these electrification scenarios on NG consumption is a reduction of 62.1 TWh (71%) and 33.1 TWh (38%), respectively. Due to the higher efficiency of HPs compared to the existing heating technology stock, the total final energy demand also declines with increasing electrification by an average of 18% between the present-day and HE scenarios. Deploying envelope improvements in parallel with HPs reduces consumption of electricity by 16% between HX and HE scenarios, and by 10% between MX and ME scenarios. Envelope improvements also induce gas demand savings of 11% and 12%, respectively.

As part of our model benchmarking, we also compare our simulated present-day numbers versus historical gas consumption in the residential sector, reported by EIA. We find that the simulated present-day numbers overestimate residential gas demand relative to EIA data (by 33-54%). Through sensitivity analysis, we identify several factors explaining this observation: a) limited number of archetypes used to approximate the building stock; b) errors intrinsic to the ResStock model (as quantified by NREL (Wilson et al. 2022)); and c) the weather data. However, upon further investigation we find that the errors do not

strongly propagate into our future-looking scenarios for 2050. Further details on the benchmarking analysis and the sources of error are discussed elsewhere (Khorramfar et al., 2023).

Implications for regional electricity peak demand

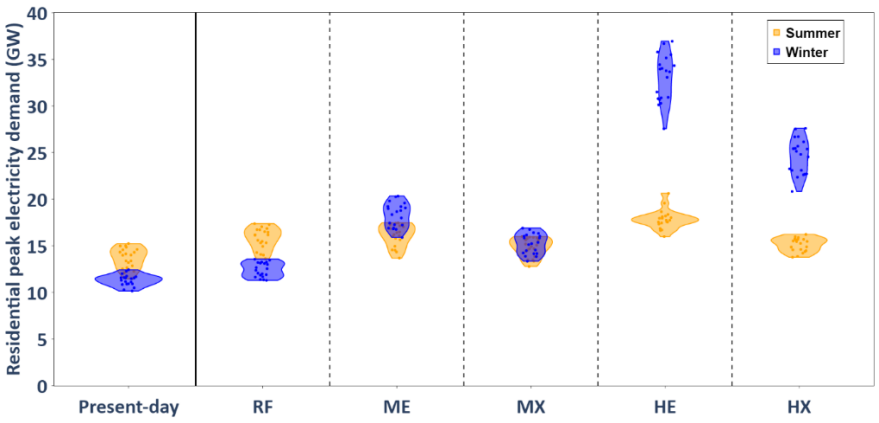


Figure 6. Summer and winter peak demands for the residential sector under different electrification scenarios. Each colored region contains demand data simulated for 20 weather years. The width of plots increases where the density of data is higher, and their height represents sensitivity toward the weather variation.

As highlighted in Figure 6, we find that peak electricity demands increase with higher amounts of electrification. The reference scenario RF results in a small average peak increase of 2.1 GW across the weather years, while ME and HE result in increasingly higher average peak increases of 4.7 and 19.3 GW, respectively. Envelope improvements significantly decrease peak electricity demand by an average of 8.4 GW for HX compared to HE and 2.6 GW for MX compared to ME. Figure 6 highlights that high electrification of the residential sector alone results in sectoral peak demands that are comparable to the present-day New England system-wide peak demands of 24.4-26.0 GW. Additionally, the range of weather-induced variation in demand (represented by the vertical spread of the plots) grows at higher electrification levels.

As an alternative to hybrid heating systems that use fossil fuel heating systems as backup, we also evaluate the impacts of all-electric heating systems that combine ASHP with electric resistance backup. Using electric resistance backup instead of fuel backup leads to much higher average peak loads and greater inter-annual variation (figure not shown), indicating policies that promote the early deployment of hybrid systems should be balanced against the risk posed by the potential replacement of existing systems with electric resistance backup upon breakdown of existing furnace/boilers. In this case, scenario ME now has the highest median peak of 47.3 GW, 28% higher than the highest peak of 36.9 GW presented under the HE scenario in the base case results shown in Figure 6.

Spatial distribution of demand changes:

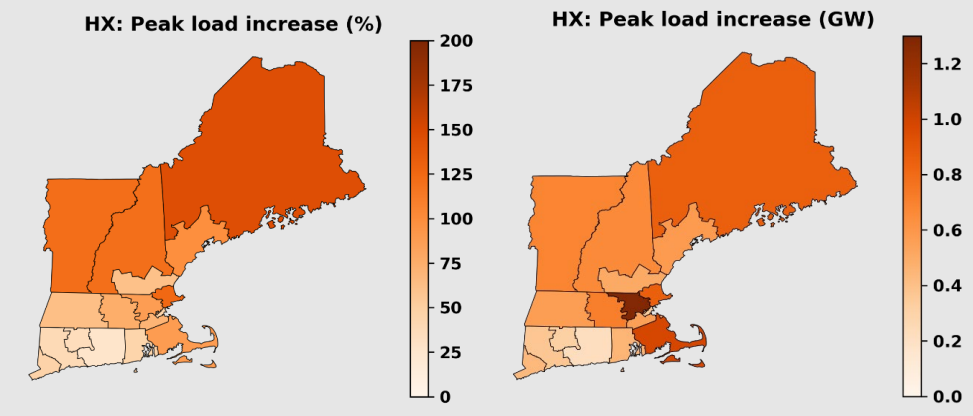


Figure 7. Average residential peak load increases across the 20 weather years for scenario HX above present-day for 17 zones in New England. Each zone has a population between 600,000 and 1.6 million.

The spatial distribution of the increase in peak loads is also important for infrastructure buildout decisions and cost allocation among ratepayers. The average load increase for scenario HX across the weather years is shown in Figure 7. As compared to gross load increases (Figure 7 left panel), we find that percent load increases (Figure 7 right panel) relative to the present day are greater in the more rural, colder regions. A key potential implication is that the demand increase in predominantly rural utility service territories could require deeper distribution network buildouts relative to the population of ratepayers who will likely incur the cost through higher tariffs. Conversely, the more densely populated southern regions of New England may not need as dramatic network upgrades, the costs of which can also be spread across larger populations. These distributional impacts may raise questions around the equity of heating electrification.

Bulk energy system impacts of heat electrification – New England case study

Impact on capacity, generation, and gas supply

We evaluate the bulk power-gas system impacts for the aforementioned bottom-up electrification scenarios described in Figures 5-7 under deep decarbonization constraints. Our observation aligns with similar studies where aggressive VRE and energy storage expansion are observed with deep decarbonization. Figure 8 shows the system outcome for one selected weather year. VRE dominates the capacity and generation, with wind generation (onshore and offshore) making up the majority of the generation mix due to its higher availability in the region. Furthermore, solar and onshore wind capacities are built to the assumed maximum resource availability limit across all scenarios, implying their further deployment in lieu of other resources, such as gas and offshore generation, in case of more land availability. Across all scenarios, substantial short-duration battery storage (Li-ion) capacity is established to compensate for the intermittent nature of VRE, ranging from 12.2 to 13.8 GW with rated duration of 3.1 to 3.8 hours. The power system retains most of the current fleet of NG-fueled plants due to planning reserve requirements, thus only sparingly using them to mainly meet peak demand. At the same time, the future power grid under heating electrification shows significant utilization of CCS-based power plants

(capacity utilization of 24-43%) despite their higher capital cost and heat rate compared to conventional gas-fueled power plants. Overall, the capacity of gas-fueled plants is 20-51% larger than the existing capacity but constitutes only 13-18% of the generation mix compared to the current 52% contribution for New England in 2022.

Impact on bulk power-NG system cost

Total system cost is one of the critical criteria for comparing various decarbonization pathways and evaluating their feasibility. The cost of establishing new power plant and storage facilities plus their associated fixed operation and maintenance (FOM) costs make up the largest portion of system cost, ranging from 44% in RF to 59% in HE scenarios. The deployment of the expensive LCF, modeled as a carbon-neutral fuel with a cost of $20/MMBtu versus $4/MMBtu for NG, increases in more stringent electrification scenarios and under deeper decarbonization targets. As reflected by the relative cost contribution of network expansion in Figure 8d, the transmission capacity increases by 13-25% compared to the current network capacity as the electrification level increases. Across the five electrification scenarios, high electrification coupled with envelope improvements, which has the lowest total sectoral final energy demand, yields the most cost-effective electrification scenario to meet decarbonization targets, as reflected in Figure 8d. Under 80% and 95% decarbonization targets, HX is 14% and 15% less costly than RF, respectively.

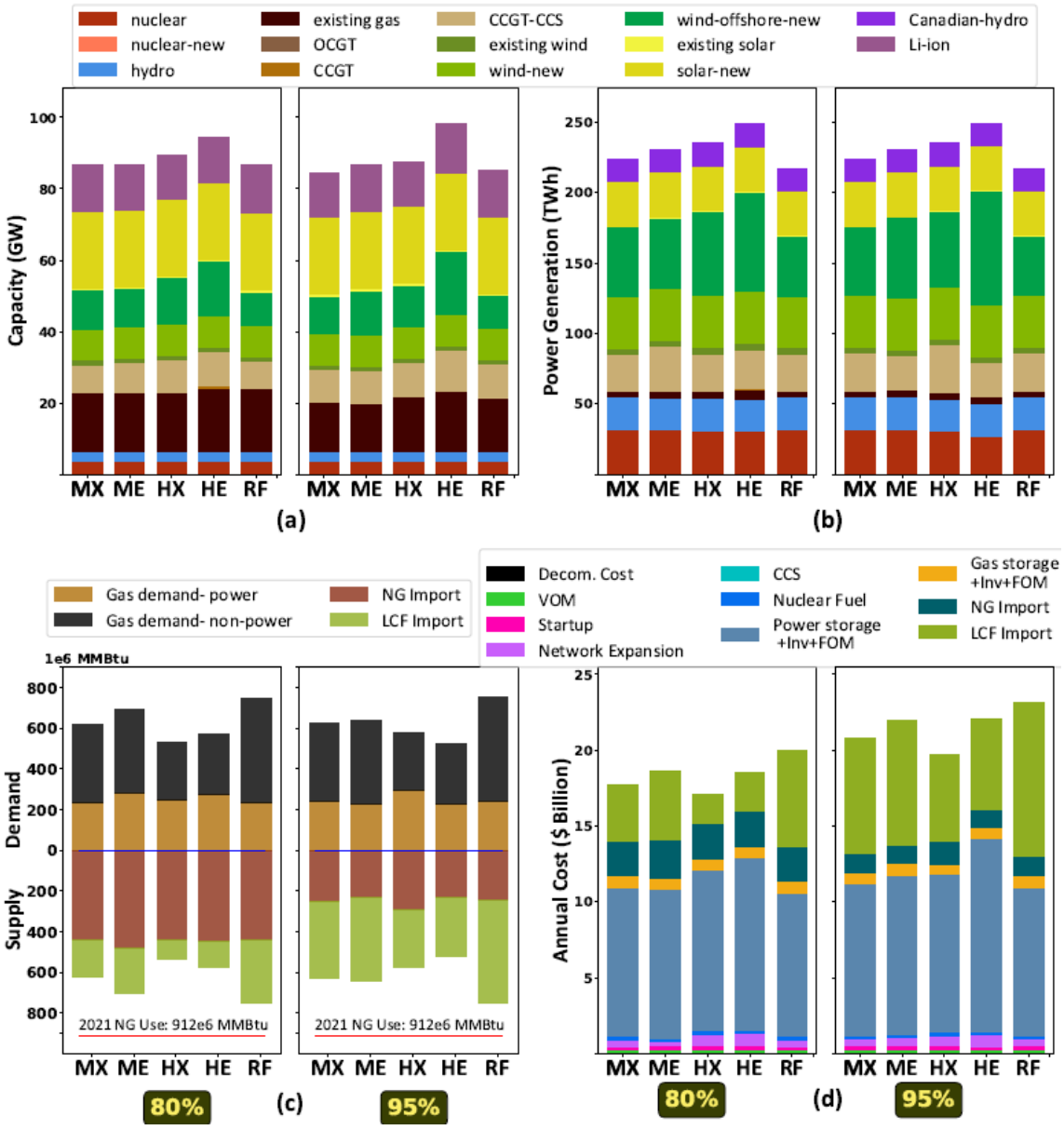


Figure 8. (a) Power capacity, (b) power generation, (c) gas consumption (top) and supply (bottom), and (d) annual system costs for the weather year 2003 under different electrification scenarios and decarbonization targets. In the upper legend, "Li-ion" is short-duration battery storage. In the lower-right legend, "VOM" and "FOM" are variable and fixed operating and maintenance costs, respectively. "CCS" is the cost of establishing carbon capture and storage infrastructure. "Power storage+Inv+FOM" is the investment and FOM costs for storage and power plants.

Impact of inter-annual variation

Inter-annual weather variation plays a key role in projections of load and VRE profiles. Evaluating these weather-dependent parameters for various weather years and electrification scenarios reveals that high electrification with envelope improvement results in the lowest average bulk power-gas system cost, as shown in *Figure* 9 (left panel). Interestingly, the business-as-usual scenario with the least electrification

(RF) has the highest average power-NG cost. This is in contrast to when power or NG system costs are considered in isolation;

Figure 9 (middle panel) shows that the power system cost is the highest for high electrification, and lowest for RF, whereas RF and HX are the least and most cost-effective options in terms of NG system cost. This observation shows that the optimal pathways may differ if energy systems are planned in isolation, thus resulting in misleading conclusions. Moreover, it suggests that the change in integrated power-gas system cost with increasing electrification is driven by savings in the gas system. Additionally, our findings indicate that envelope improvements are key to achieving the least-cost system outcome and should be incorporated in beneficial electrification initiatives. Sample calculations conducted in this study (not detailed here – see SI of working paper (Khorramfar et al. 2023)) suggest that the bulk power-gas system savings of envelope improvements at high electrification levels can offset 30-50% of the installed costs of the envelope retrofits, even before accounting for other system benefits (including those to health and distribution system savings).

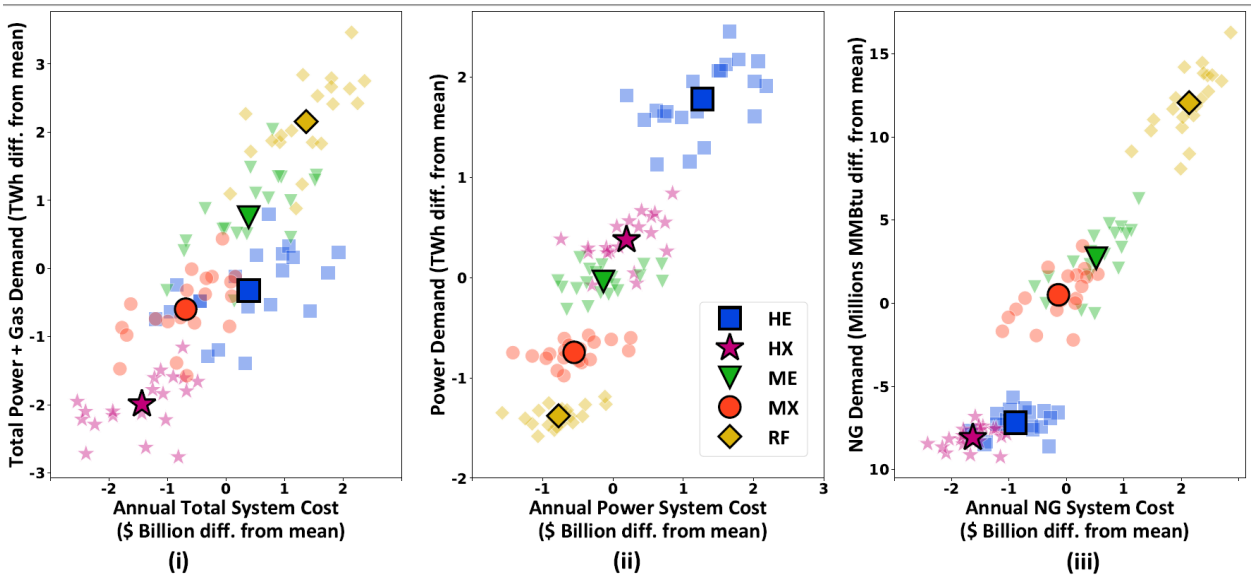


Figure 9. Total bulk power-gas system cost versus energy consumption under the 80% decarbonization scenario. The left figure compares the combined system cost with the combined energy demand for power and NG. The middle and right figures have the same individual comparisons for power and gas with their corresponding demands. Costs are normalized according to their difference with the corresponding costs for weather year 2003 for all scenarios and decarbonization targets. Translucent points show all 20 weather years for each electrification scenario, while bold points indicate the averages. Note that bulk power-gas system costs do not include end-use cost of electrification, such as HP *and envelope improvement retrofits as well as electricity and gas distribution infrastructure costs.*

Role for emerging technologies: CCS-based power generation and long-duration energy storage (LDES)

Our analysis shows that the impact of CCS technology on power-gas system outcomes largely depends on the decarbonization target. Under the 80% decarbonization target, the system cost without CCS is comparable to the case with CCS, whereas its absence increases system costs by 5.4 to 16% under the more stringent 95% emissions reduction goal. The importance of low-carbon firm dispatchable resources

such as CCS-based power plants increases under more stringent decarbonization targets. In the absence of the CCS technology, the power system relies more on offshore wind and unabated gas power capacity, which requires using more LCF for power generation. The larger share of offshore wind, in turn, increases the need for battery storage, especially under the 95% target. Overall, across five electrification scenarios, the absence of CCS power generation leads to 22-39% and 13-185% increase in offshore capacity, 32-46% and 10-34% increase in unabated thermal capacity, and up to 3% and 27% increase for storage capacity for 80% and 95% emissions reductions targets, respectively.

LDES is another emerging technology with a potential to play a major role in the energy transition. LDES technologies are varied, but all are characterized by much lower energy capital costs, round-trip efficiencies, and higher power capital costs compared to current Li-ion storage systems. Here, we evaluate the role for LDES in power-gas system decarbonization under high electrification scenarios. For illustrative purposes, we model LDES based on two possible cost projections for metal-air batteries (MIT Energy Initiative 2022). As highlighted in Figure 11, the availability of LDES generally shifts the power system to rely more on wind power over CCS generation, solar and short-duration Li-ion battery storage, especially under scenarios with low-cost LDES technology availability. Importantly, the adoption of LDES reduces the extent of coupling between the power and gas systems by reducing the consumption of gas (NG and LCF) by 78-95% and 11-31% under low- and high-cost estimations, respectively. Total power-gas cost is reduced by 3.2-4.5% and 0.2-0.3% in the low and high cost LDES scenarios, respectively.

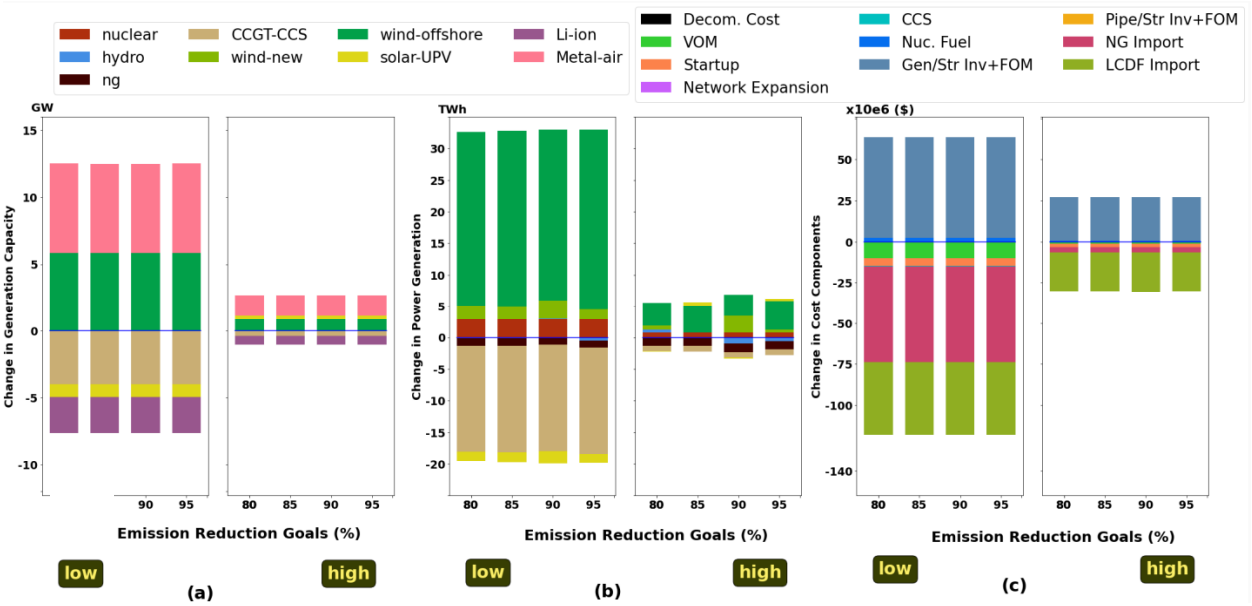


Figure 10: Difference in capacity (left), generation (middle), and cost components (right) between low and high LDES cost estimates under the HE scenario. Further details are presented in the working paper(Khorramfar et al., 2023)

Distribution network impacts of heat electrification

Heat pump technology cost characterization

To accurately capture cost impacts of electrification, we undertake an empirical analysis to catalogue the cost of HP installations in residential buildings, using data from the Massachusetts Clean Energy Center

(MassCEC). The dataset has 163 projects completed between 2019 and 2021 and provides a realistic view of the installed costs of whole-home and partial-home HPs. By cross-referencing this data with the NEEP technical specifications for cold-climate HPs (Northeast Energy Efficiency Partnerships n.d.), we are able to understand the variance in installed costs based on such factors as capacity and efficiency.

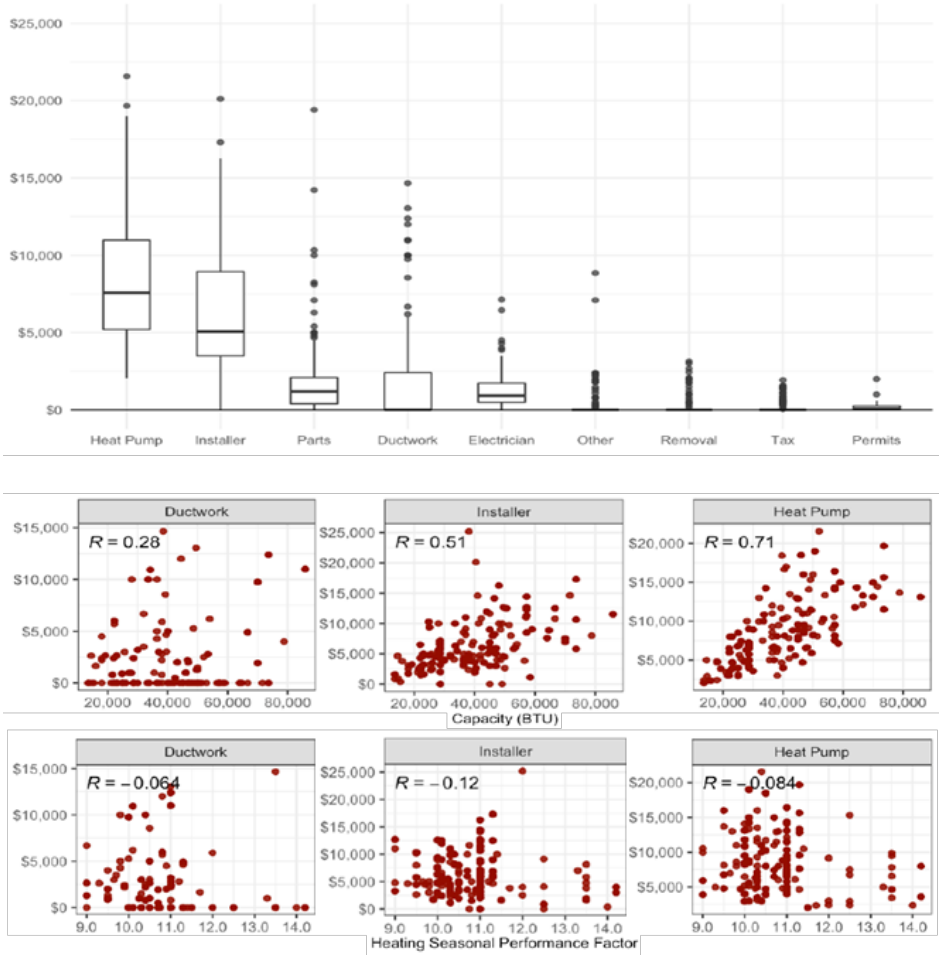


Figure 11. Top: Box plot of cost components of whole-home HP electrification projects in Massachusetts in 2019-2021. Bottom: Regression analysis of main cost components—HP, installer, ductwork—against HP capacity and heating efficiency "Heating Seasonal Performance Factor" on the same dataset.

The database contains both whole-home and partial-home projects. The partial-home data are likely incomplete, typically involving AC replacements and include supplemental heating. Using only whole-home data, we build a cost estimation model for the electrification of space heating with whole-home ASHPs. This model considers a range of HP options and incorporates the building's thermal demand, capital and operational energy costs, and utility rates. This approach allows us to provide a detailed and transparent analysis of costs of HPs presenting, highlighting the potential costs of electrifying space heating for a typical home.

As shown in Table 1, the model estimates costs ranging from approximately $19,000 to $30,000 for a typical 1700 sq-ft home, reflecting the variance of installed costs by capacity and efficiency. This wide range contrasts with previous studies' underestimations, which were below $10,000. The analysis of the cost database also highlights that although the cost of the heat pump is the single largest cost component, the equipment accounts for only 41% of total project cost (Figure 12a). Therefore, along with equipment cost reduction, further reduction in non-equipment costs would be critical to enable widespread adoption of heat pumps.

Table 1. Modeled relative installed costs of whole-home ASHP options for a 1,700 square foot Massachusetts home that does not already have ductwork. The total cost includes appliance, labor, ductwork, and miscellaneous costs (parts, furnace removal, permits, etc.); 37,000 BTU per hour thermal capacity, HSPF=10 and $19,020 cost are used as basis. HSPF stands for Heating Seasonal Performance Factor and is a performance metric that expresses the total heat output during the space heating season, in BTU, divided by the total electrical energy consumed during the heating season, in Wh.

	HSPF=10	HSPF=11	HSPF=12
37,000 BTU/hr	$19,020	+4.3%	+8.7%
46,500 BTU/hr	12.5%	17.6%	22.8%
57,200 BTU/hr	26.7%	32.6%	38.5%
70,000 BTU/hr	43.7%	50.5%	57.4%

Impacts under existing tariff structures

It is important to consider both capital cost and operating cost of HPs versus traditional gas-based heating systems to better understand the end-user perspective of HP adoption. The earlier discussion of HP capital costs highlights how equipment costs are only a portion of total installed capital costs, necessitating public policy support to lower the upfront cost of their adoption. The operating costs for HPs, like NG equipment, are governed by retail tariffs that vary widely across jurisdictions. Under average national retail rates[1], the high capital costs of HPs versus high-efficiency gas furnaces and boilers outweigh the operational savings and make HPs an uneconomical investment. Furthermore, the annual cost ratio of electricity (~$0.22/kWh) to natural gas (~$0.05/kWh) under 2021 flat rates in Massachusetts poses an additional challenge to achieving widespread electrification of space heating (*Massachusetts Household Heating Costs: Estimate of Energy Prices for Heating Fuels for the 2023/24 Winter Heating Season* n.d.). This

[1] According to the Energy Information Administration, the national average rates were $0.106/kWh for electricity, $0.037/kWh for gas, and $0.063/kWh for distillate home heating oil

suggests that in addition to addressing capital cost of HPs, reforming electricity retail rates would be critical to expand HP adoption and building electrification-based decarbonization. Currently, many emissions-reductions programs are financed through explicit or implicit additions to electricity rates. Examples include efficiency programs, distributed generation support programs, and Renewable Portfolio Standards, all of which increase electricity rates and thus deter electrification.

Electricity rates are also likely to be impacted by the level of distribution network investment undertaken to support increased electricity use in buildings. To explore this question, we investigate the network impacts of different levels of HP penetration in a prototypical suburban distribution feeder for the Massachusetts region. We find that HPs increase winter loads and reduce summer loads, leading to a winter-peaking system above 25% adoption for the sample feeder used in the study (Figure 13 left panel). Interestingly, below 25% adoption, we do not observe any operational constraints being violated, which suggests that there may be potential for some amount of so-called "beneficial" electrification via HPs whereby additional load from heating applies downward pressure on utility rates. However, distribution issues emerge above 45% adoption, with substation-level transformers being the most immediate and costly investment need. Full electrification integration costs are estimated from $292 to $1,460 per residential customer (Figure 13 right panel) as obtained after a review of diverse studies that estimate incremental distribution capacity costs, inclusive of transformer upgrades, ranging from $100/kW to $500/kW.

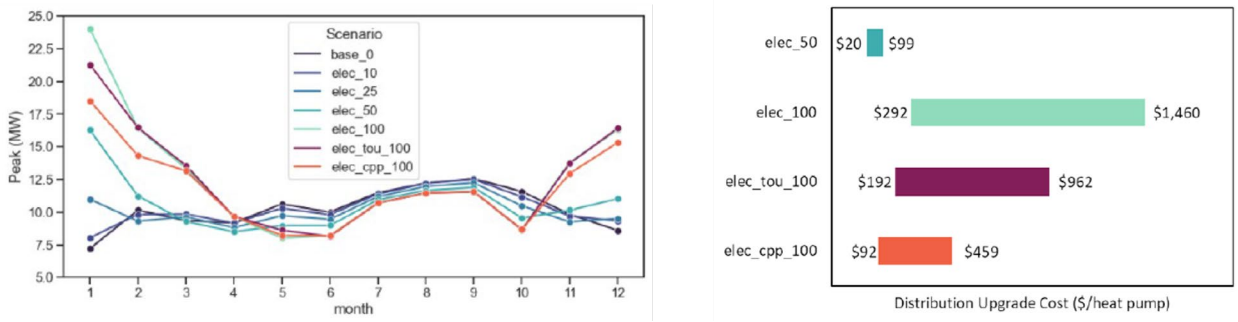


Figure 12. Left: Estimated monthly peak demand at the substation (16 MVA transformer capacity) for the modeled distribution feeder. Right: Distribution-level upgrade costs per heat pump customer in constrained scenarios for the modeled distribution feeder. Levels 0, 10, 25, 50, and 100 indicate percentage HP electrification. Upgrade costs are calculated by multiplying the capacity cost range – $100/kW (Synapse Energy Economics 2021) (lower bound) to $500/kW (Cutter, Eric et al. 2021) (upper bound) – by the amount that the peak demand exceeds the substation capacity limit. That total is divided by the number of customers who have a heat pump installed; all cases are under flat retail rate, except for tou: time of use and cpp: critical peak pricing.

Impacts of temporally varying rate structures: - Time-Of-Use (TOU) and Critical Peak Pricing (CPP)

Our Massachusetts feeder model also highlights the critical role of advanced rate design in managing demand and facilitating higher levels of HP adoption. Optimal responses to Time-Of-Use (TOU) and Critical

Peak Pricing (CPP) rates[2] can reduce peak demand by 11% and 23% respectively, under full electrification. These significant peak-load reductions are a result of pre-heating buildings (assumed to be the only controllable load in this study) during off-peak hours. Consequently, the constrained network can now support a higher adoption of HPs before issues emerge —from approximately 45% to around 50% under TOU rates, and up to about 60% under CPP rates. Adoption of such advanced rates requires, among other things, the installation of advanced metering equipment. Our study quantifies how innovative rate designs and mechanisms that incentivize thermal load shifting to reduce peak impacts make operating HP systems more economical.

Under full heating electrification, adoption of TOU and CPP rates cannot avoid increases in peak demand. These new peaks could necessitate additional local network reinforcements or non-wires alternatives and escalate total network costs. Nonetheless, as shown in Figure 13, the resulting network reinforcement costs will be substantially lower with TOU and CPP rates, as compared to traditional flat volumetric consumption tariffs.

Impact of spatially resolved network charges

The above analysis highlights the value of rate designs that include temporally varying volumetric retail tariffs, increasing levels of heat electrification without triggering network upgrades. When implemented at scale, such rates could elicit a more uniform consumer response as opposed to flat retail tariffs, where heterogeneity in consumer load profiles also introduces heterogeneity in overall load shape. The result might be that the peak load is shifted to hours right after the end of a high-priced period. This "peak-shifting" or "snapback" effect may undermine the value of time-varying energy component of retail tariffs and thus other complementary approaches are needed in the rate design.

In addition, we investigate the merits of altering the cost-allocation model from a traditional cost-causality principle, under which customers are charged based on their responsibility for each network cost component in the current system, to a model where customers are charged based on their marginal contribution to future network costs. This is known as long-term incremental costs or forward-looking network tariffs.

To prevent the peak-shifting effect resulting from flat network tariffs and capture long-term incremental network costs, there is a need for network tariffs that are both more locationally differentiated and dynamic. To manage rapidly fluctuating network usage, tariffs should be adjusted promptly. In response, we formulate an alternative coordination mechanism as a local network capacity market in which customers can book in advance their expected usage of network capacity and deviation of actual consumption from booked capacity is priced ex-post. Concretely, the local network capacity market takes the form of an ascending clock auction, where the distribution system operator identifies critical days and calls for offers. Customers, directly or through retailers or aggregators, bid their offers for each hour of the next critical day. Three situations depend on the offers and the total network capacity: 1) the clearing

[2] The rates are designed to be revenue neutral when compared to the flat rate. For the TOU rate, we employ a 3:1 on- to off-peak ratio, $0.33/kWh and $0.11/kWh. On-peak hours are set 4am to 9am and 5pm to 10pm October to May, while on-peak hours are set 7am to 6pm June to September. For the CPP rate, we employ a 12:2;1 ratio: $1.35/kWh during 100 critical peak hours, recovering 25% of revenue requirement; and $0.25/kWh and $0.12/kWh during same on-peak and off-peak hours.

price is zero when the requested capacity is below the usage threshold (capacity that does not produce any increment in future network costs); 2) the clearing price linearly increases with network usage when the requested capacity is between the threshold and the network limit; and 3) the clearing price reaches its maximum (the so-called peak coincident network charge) and a certain number of customers cannot be granted network access. Further details are provided elsewhere (Morell-Dameto et al. 2024).

The study compares different implementations of forward-looking network tariffs: 1) in the first case (L-20%) forward-looking charges take the form of an ex-ante hourly energy charge during peak hours (1200 in this case); 2) in the second case (LC-20%), hourly energy charges are calculated ex-post and are higher during actual peak hours. In the second case, customers can book network capacity ex-ante through the proposed coordination mechanism. In both cases, non-distortionary fixed residual charges ($/year) are applied to ensure cost-recovery. The assumption for the energy tariff in both cases is a flat energy charge, to avoid possible distortions in the results. Both tariffs are tested in a 10,000-customer LV network area in the Slovenian system where 20% of customers adopt HPs as a flexible load-control device. The chosen area is densely populated with blocks of apartments (less diversity of consumption patterns) and characterized by cold winters (similar to urban areas in New England), which exacerbates peak shifting impacts.

The study shows (Figure 14) that under scenario LC-20%, ex-post network charges increase when network usage surpasses the threshold. Individual customers face ex-post network charges when their network usage surpasses their booked capacity. Consequently, customers are incentivized to collectively use the network below the threshold. Although the total energy consumed in scenarios LC-20% and L-20% are very similar (around 41.2 GWh), the number of hours surpassing the network capacity limit is 0 in scenario LC-20% compared to 155 hours in L-20%, which leads to earlier network reinforcements in L-20%. The infused complexity highlights the crucial role of aggregators and retailers as intermediaries in simplifying complex tariff structures for customers and representing customer interests in electricity markets. Acknowledging the practical and implementation challenges, the study paves the way for innovative rate designs and coordination mechanisms.

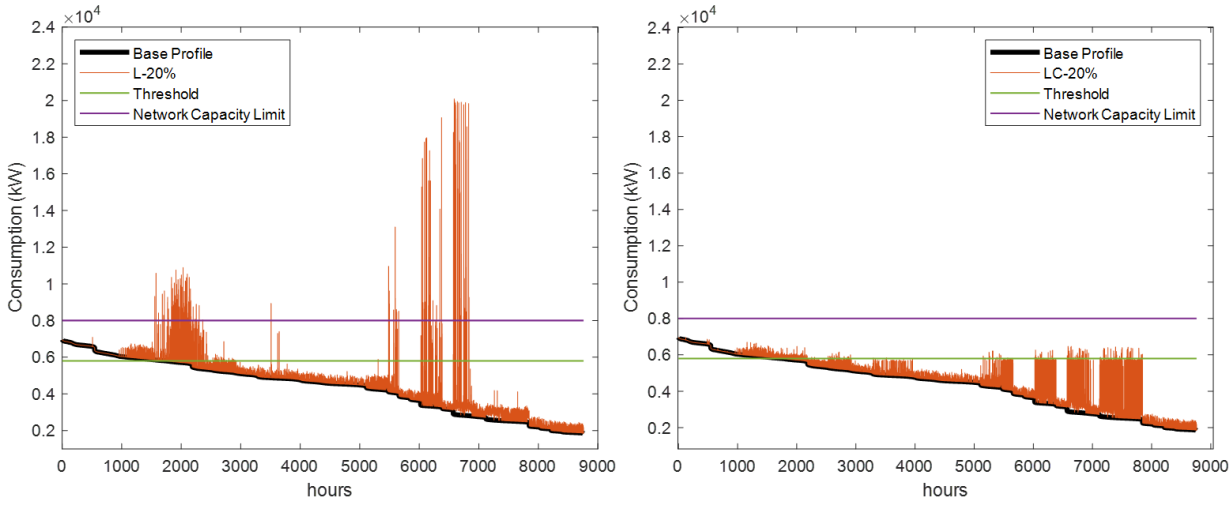


Figure 13. Load duration curve when 20% of customers install HPs (scenario L-20%) and respond to forward-looking charges with locational granularity without a coordination mechanism (left) and with the proposed coordination mechanism (right).

Project contribution to decarbonization

This work evaluates multiple under-explored questions pertaining to the system implications of heating electrification, which will undoubtedly be a challenging area in coming years. We summarize key contributions to decarbonization as follows:

1. Focusing our case studies on a particularly challenging, cold climate region with an aging housing stock furnishes robust conclusions that can be extrapolated to decarbonization efforts in other locations. We demonstrate that, especially in such regions, deep heating electrification can lead to significant demand impacts that may be potentially costly if not managed properly. However, we also identify key demand-side opportunities that can facilitate beneficial electrification. Two relatively low-cost measures can mitigate peak demand impacts of electrification and associated cost impacts: a) retail rate design to lower the end-user cost of electrification and mitigate distribution network impacts via incentivizing time-shifting of demand, and b) envelope improvements that reduce average and peak electricity consumption, and potentially provide a hedge against inter-annual weather variations.
2. We highlight the critical importance that weather variability has in heat decarbonization. Existing projections of heating electrification system impacts typically neglect the uncertainty caused by the weather-sensitivity of heating loads and variability in air source heat pump efficiency. We present one of the first quantifications of this variability and highlight the value of a diverse supply-side resource mix as necessary to yield decarbonized energy infrastructure systems that can withstand inter-annual variability in energy demand and supply.
3. We establish rigorous projections of regional demand impacts of electrification and identify potential supply-side resource mixes that can meet these demand challenges in a cost-effective manner. In so doing, we identify a handful of key themes pertaining to cost-effective power-gas system planning. Importantly, high electrification in the residential sector results in the least-cost bulk system outcome. Envelope efficiency improvements are essential to obtaining the least-cost outcome under any amount of electrification.

4. In addition, we intend to publish the related data and methods openly for use and emulation by stakeholders; some of these work products are already in use by other research groups.
5. We reveal key equity-related considerations that must be considered on the path to heating decarbonization. In New England, the electricity demand impacts of electrification will be spatially heterogeneous and relatively higher in rural, lower-income areas. At a more granular level, certain distribution feeders will incur more infrastructure costs than others, which may be problematic for traditional cost allocation principles that socialize network investments across all customers within a utility's service territory. Furthermore, heat pump installed costs are currently high, hindering adoption by low-income consumers, reducing the potential for beneficial electrification. These findings illustrate risks and obstacles that will have to be navigated by stakeholders to ensure socially beneficial electrification and decarbonization.

The following directions for future work could serve to expand the analysis presented here:

1. Representation of flexibility measures beyond rate structures, including direct load control, distributed energy storage, and EV charging flexibility;
2. Development of a robust optimization framework that explicitly accounts for inter-annual weather variability across a multi-decade time horizon (for example, the 20 weather years considered in the bottom-up regional demand analysis presented here);
3. Development of a surrogate machine-learning model to emulate the bottom-up demand modeling framework presented here and facilitate a more adaptable estimation of heat electrification demand impacts in other regions (including plans for the PJM interconnect);
4. Estimation of future impacts of heating electrification in the commercial building sector, which is also a weather-varying source of load that has received less attention in the literature as compared to the residential sector;
5. Evaluation of cost allocation and incentive structures under various scenarios of HP installation costs and their cascading system impacts (perhaps modeled in a manner similar to the work done here);
6. A targeted analysis of the role of low-carbon NG substitutes, including sensitivities to cost, emissions intensities, and resource availability, all of which are highly uncertain in the future context. Assessment of public acceptance of various decarbonization technologies could also be useful.
7. Comparative analysis of distribution upgrades needed to support heating electrification in urban versus rural utility service territories.

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