Implications of heating electrification on distribution networks and distributed energy resources

by

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Abstract

The electricity sector's transformation towards renewables, combined with technological improvements in electric appliances, has enabled *electrification* as a decarbonization pathway for other sectors. Electric heat pumps are an attractive solution for space heating, which is still largely served by direct combustion of fossil fuels. While current deployments are still low, widespread adoption of heat pumps is required to achieve emissions reductions consistent with global climate targets.

This thesis explores the impacts of residential heat pumps on electric distribution systems operations and planning. In the network studied, we find that heat pumps increase winter loads and reduce summer loads, leading to a winter-peaking system above 25% adoption and indicating near-term potential for "beneficial" heating electrification. Distribution issues emerge above 45% adoption on the network studied: substation-level transformers are the most immediate and costly investment need, and voltage quality becomes an issue near full adoption. Time-varying rate designs can induce consumers to shift heating demand and reduce peak impacts, increasing electrification levels on a constrained network from 45% to 50–60% with the rates tested. As heat pumps reshape residential electricity demand, accurate price signals for distributed energy resources are essential for efficient grid operation and investments.

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Table of Contents

1. Introduction 6

1.1. Building Electrification through Heat Pumps 6

1.2. Grid Impacts of Heating Electrification 7

1.3. Study Scope and Outline 8

2. Heating Electrification Efforts in the United States 9

2.1. Heat Pumps and Residential Space Heating Overview 10

2.2. Heating Electrification Policies 12

2.3. Barriers and Opportunities for Heating Electrification 14

3. Regulation of Distribution Systems with Heating Electrification 17

3.1. Evolution of Distribution System Planning and Regulation 17

3.2. Technical Considerations of Distribution Networks 22

3.3. Literature on Heating Electrification Load Impacts 25

4. Simulating Heating Electrification on a Residential Distribution System 29

4.1. Overview of Modeling Process 29

4.2. Model Selection and Configuration 30

4.3. Defining Electrification and Tariff Scenarios 31

4.4. Preparing Building and Distribution Network Models 36

4.5. Distribution Impacts of Heating Electrification 38

4.6. Heat Pump Integration Costs 43

4.7. Model Limitations 44

5. Discussion and Conclusions 46

5.1. Summary and Key Findings 46

5.2. Policy Implications 47

6. References 49

List of Figures

Figure 1: Residential Heating Technologies by Climate Region, 2015 11
Figure 2: Layout of a Typical U.S. Distribution System 23
Figure 3: Illustrative Voltage Drop Along Radial Distribution Feeder 24
Figure 4: U.S. Electric Distribution Spending, Customers, and Sales, 2000-2019 25
Figure 5: Heat Pump Performance Curves 34
Figure 6: Electricity Tariff Scenarios 34
Figure 7: Heating-Focused Rate Designs 35
Figure 8: Network Topology and Power Flows in Base Case 37
Figure 9: Network Building Characteristics 38
Figure 10: Monthly Substation Peak Demand 38
Figure 11: Substation Load in Peak Heating Week 40
Figure 12: Substation Load in Peak Cooling Week 40
Figure 13: Substation Load Duration Curve 41
Figure 14: Voltage Drop Along Longest Feeder 42
Figure 15: Power Flow Results for 100% Electrification, Flat Rate Scenario 43
Figure 16: Distribution Integration Costs in Constrained Scenarios 44

List of Tables

Table 1: Nominal Transmission and Distribution Voltages in the U.S. 22
Table 2: Summary of Electrification and Tariff Scenarios 32
Table 3: Customer Peak Demand Characteristics 37
Table 4: Load and Power Flow Results 42

1. Introduction

The transformation of electricity generation towards more renewable and lower-emitting sources has enabled *electrification* as a mechanism for reducing greenhouse gas emissions. Substantial electrification of industry, transport, and building sectors - "electrifying everything" - is required in virtually every study of decarbonization pathways consistent with global climate goals, including net zero emissions by midcentury (Larson et al. 2021, IEA 2021a). Shifting these sectors of the economy from fossil fuels to low-carbon electricity is an enormous undertaking that requires both immediate, massive deployments of solutions that exist today and continued innovation to develop breakthrough technologies.

In this thesis, we analyze how electrifying space heating impacts electricity distribution systems and explore the critical role of utility regulation and rate design in facilitating electrification.

1.1. Building Electrification through Heat Pumps

Burning fossil fuels in buildings contributed to 13% of 2020 U.S. greenhouse gas emissions or ~680 million metrics tons of CO_2 (US EPA 2022). The largest end-use contributor to these emissions is space heating, which relies on fossil fuels in two-thirds of buildings (US EIA 2016). In the research literature and increasingly in U.S. state policies, the playbook for decarbonizing buildings involves increasing the efficiency of building envelopes and replacing fossil-based heating systems with high efficiency electric heat pumps.[1] With clean electricity supply, such a transition would reduce greenhouse gas and criteria pollutant emissions.

Electric heat pumps can provide both space heating and cooling, and can operate much more efficiently than traditional heating systems. Heat pumps were present in 10% of U.S. homes in 2015, concentrated mostly in warmer regions like the Southeast where electricity is affordable and heating demands are low (US EIA 2016). To achieve net zero in 2050, the International Energy Agency (IEA) models heat pumps in two-thirds of U.S. and European homes, and Princeton researchers model heat pumps in 50 to 80% of U.S. homes (IEA 2021a, Larson et al. 2021). Because heating systems are long-lived assets, achieving the IEA's target requires completely

[1] While other technologies like hydrogen and renewable natural gas can technically provide clean heat, optimal decarbonization scenarios allocate limited supplies of low-carbon fuels to hard-to-decarbonize sectors such as aviation and industrial processes (Baldino, O'Malley, and Searle 2021, Larson et al. 2021) .

phasing out fossil heating in new homes by 2025 and retrofitting existing homes with heat pumps at an annual rate of 2.5% per year, which is 25 times the current rate of home retrofits under existing federal programs (Amann, Srivastava, and Henner 2021).

Many heat pumps will need to be installed in regions where they have traditionally been unpopular. To overcome adoption barriers, states such as Massachusetts, New York, and California have set ambitious heat pump targets, created consumer and contractor awareness programs, and set aside substantial funds to incentivize heat pumps through rebates (Cohn and Esram 2022). In addition, a growing number of cities such as Berkeley, Seattle, and Brookline have banned natural gas connections in new buildings (DiChristopher 2021b). These efforts illustrate a rough plan for decarbonizing buildings, but absent sweeping policy mandates the adoption of heat pumps will depend on decentralized, private decisions by property owners. This means that economic factors, such as equipment costs and operating costs, and non-cost factors such as contractor expertise and consumer awareness will affect actual heat pump deployment.

1.2. Grid Impacts of Heating Electrification

When installed to replace fossil heat, heat pumps will increase building electricity demand. Exactly how much demand increases depends on how efficient each building is at retaining heat. The IEA estimates that 55% heat pump adoption in 2050 increases building electricity demand by 35% compared to current levels (IEA 2021a).

In addition to increasing annual electric demand, heating electrification can have major effects on load shapes and peak demand. This is important because grid infrastructure planning and generator maintenance scheduling is largely determined based on peak demand, which currently occurs in the hottest periods of summer months in most locations. Some estimates suggest that full electrification with heat pumps would increase peak demand by 70% (Waite and Modi 2020). These changes are sensitive to assumptions on demand-side flexibility, or how much heating loads can be shifted to lessen peak impacts. As NREL researchers conclude, how electrification impacts load shapes can have significant consequences for utility planning, grid operations, reliability assessments, and electricity markets (Mai et al. 2018).

The load shape impacts of incremental heat pump adoption will first be felt on distribution systems, which represent the “grid edge”. Distribution grids are the local, low-voltage networks that deliver the last mile of electricity to homes. They are mostly owned and operated by utilities under cost

of service, rate of return regulation. The uptake of distributed energy resources (DERs), primarily rooftop solar but also electric vehicles and battery storage, has complicated traditional distribution planning. Meanwhile, distribution costs have risen three times more than the customer growth and six times more than load growth since 2000, primarily due to costs related to grid modernization and replacement of aging infrastructure (US EIA 2021).

If heat pumps reshape electricity demand in ways that overload distribution grids, it could require costly infrastructure upgrades and further increase in distribution costs, which would weaken the economics of electrification. Conversely, if heat pumps increase the average utilization of distribution grids, they could lower distribution costs and improve electrification economics, at least until distribution upgrades are required. Whether distribution systems enable or impede electrification will depend on how consumers operate heat pumps, how utilities plan for heat pump impacts, and how regulators improve distribution planning to integrate DERs and other non-wires alternatives as solutions to future grid challenges.

1.3. Study Scope and Outline

Widespread adoption of heat pumps is an essential part of deep decarbonization efforts. This thesis explores the potential impacts of residential heat pumps on distribution operations, network investments, and utility regulation. We develop a modeling framework to inform the following research questions: (1) what are the impacts of heat pumps on household electricity demand, (2) what kinds of distribution issues occur at different levels of heat pump adoption, and (3) to what extent can rate design reshape heating demand and mitigate these grid impacts.

This thesis is organized as follows: Chapter 2 summarizes heating electrification efforts in the U.S. and current challenges to heat pump adoption. Chapter 3 describes frameworks for regulating utilities in a world with greater DERs and demand-side solutions. Chapter 4 models the impacts of heat pump adoption on an illustrative residential distribution network in Massachusetts across different rate designs. Chapter 5 concludes and offers suggestions for regulating utilities with high levels of electrification and distributed energy resources.

2. Heating Electrification Efforts in the United States

Avoiding the worst effects of climate change requires considerable greenhouse emissions reductions across all sectors of the economy. Most credible pathways to decarbonization anticipate two important roles for the electricity sector: reducing emissions from electric generation to near-zero by 2050, and replacing fossil fuels used in sectors such as transportation and buildings with clean electricity, also known as *electrification* (Jenkins, Luke, and Thernstrom 2018).

Over the past two decades, the United States has made substantial progress in cleaning up its power grid. Thanks to a combination of policy, market, and technology drivers, electric generation emissions in 2020 were 50% lower than the U.S. Energy Information Administration's (EIA) 2005 projections (Wiser et al. 2021). Today, new solar, wind, and energy storage capacity in U.S. interconnection queues exceeds total existing installed generation capacity (Rand et al. 2021), and 21 states plus the District of Columbia have enacted 100% clean energy targets by 2050 (Clean Energy States Alliance 2022). These trends suggest the carbon intensity of electricity will continue to fall.

For residential and commercial buildings, the main route for electrification is to replace fossil-based heating systems with electric heat pumps. A wide range of policies to accelerate heating electrification have emerged at municipal, state, and federal levels. These efforts have helped increase U.S. annual shipments of heat pumps from 2.3 million units in 2015 to 3.4 million in 2020 as heat pumps have become more popular in new construction (IEA 2021b). However, the market for heat pump retrofits remains nascent and well below levels needed to achieve decarbonization targets for the building sector. As the climate imperative to eliminate fossil fuels from buildings becomes more urgent, state and municipal policymakers have enacted policies that strengthen building codes to incentivize all-electric construction, establish emissions targets and transition plans for gas utilities, and expand energy efficiency programs to support building electrification (RMI 2021).

This Chapter presents the technology and policy context for analyzing the electrification of residential heat. It begins with an overview of heat pumps, their potential impacts, and the current state of residential heating technology in the United States. A survey of programs that have emerged to advance heating electrification follows. It concludes with a summary of adoption barriers that remain and opportunities for policy action.

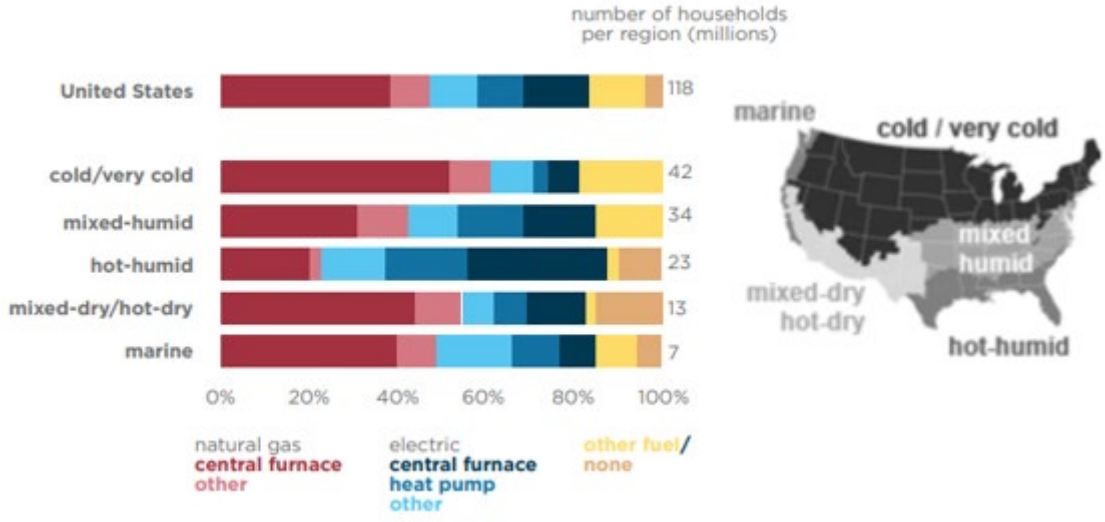
2.1. Heat Pumps and Residential Space Heating Overview

In the United States, the main technologies used for space heating are furnaces, boilers, and electric resistance heaters. Furnaces burn fossil fuels or use electric resistance heaters to generate warm air and circulate it through ducts. Boilers operate similarly but heat up water which is then distributed to radiators. Resistance heaters generate heat by passing electricity through resistors.

Heat pumps are essentially reversible air conditioners that can both heat and cool. They use a vapor-compression cycle to move heat from lower-temperature areas to higher-temperature areas. Heat pumps come in two varieties: air source (ASHPs) and ground source or geothermal (GSHPs). ASHPs exchange heat with the surrounding air, whereas GSHPs use an underground loop for heat exchange. ASHPs are more common, less expensive, and simpler to install than GSHPs. Because GSHPs require more land and upfront cost, most electrification and deep decarbonization studies focus on ASHPs as the primary scalable solution for clean heat (Jadun et al. 2017, Larson et al. 2021). By moving heat rather than converting potential energy, heat pumps can be three to four times more efficient than furnaces, boilers, and resistance heaters at providing heat (Jadun et al. 2017). This efficiency advantage means that heat pumps can reduce the carbon intensity of space heating even when electricity supply is not fully decarbonized: the IEA estimates that with the 2020 U.S. average grid mix, heat pumps have 55% lower net greenhouse gas emissions than the most efficient natural gas boilers (IEA 2021b).

The U.S. residential sector relies heavily on fossil fuels for heating. In 2015, roughly 45% of homes had natural gas heating systems, and 15% had systems that burned fuel oil (US EIA 2016). Only a third of homes use electric heating, and only 10% of homes had heat pumps. As a result, space heating represents one of the largest potential opportunities for electrification in the residential sector. The choice of heating equipment varies considerably based on local climates. Figure 1 illustrates the distribution of heating technologies across U.S. climate regions in 2015.

Figure 1: Residential Heating Technologies by Climate Region, 2015



Source: Kaufman et al. (2019).

As shown above, natural gas and fuel oil are predominantly used for heating in colder regions, and electric heating is mostly used in warmer regions. While electric heat pumps exist in all regions, they are mostly concentrated in the hot-humid and mixed-humid climates of Southeast and Mid-Atlantic where heating demands and electricity prices are lower (Kaufman et al. 2019). This trend reflects an important drawback of heat pumps: their efficiency advantage over conventional systems decreases with lower temperatures (Pantano et al. 2021). A measure of heating efficiency for heat pumps is the coefficient of performance (COP), which is the amount of heat delivered per unit of electricity consumed.[2] For cold-climate specific ASHPs, COPs are typically around 4-5 when outdoor temperatures are above 10 degrees Celsius, and are roughly halved to 2-2.5 when temperatures fall to -10 degrees Celsius.[3] As the COP for a typical fossil-based furnace is 0.85 and for electric resistance heating is 1.0, heat pumps are still more efficient than conventional heating systems (Pantano et al. 2021).

Despite their higher efficiency, heat pump economics remain challenging in many parts of the U.S. because heat pumps have higher upfront costs than furnaces or boilers, and electricity is often more

[2] Other common measures include Seasonal Coefficient of Performance (SCOP), calculated as the total heating delivered over the heating season divided by the total energy consumed, and Heating Season Performance Factor (HSPF), calculated as HSPF = SCOP x 3.412 (Jadun et al. 2017).
[3] Ranges based on the median of a database of over 1,000 cold-climate ASHPs maintained by the Northeast Energy Efficiency Partnerships (NEEP 2022a).

expensive than natural gas (Billimoria et al. 2018). RMI authors find that heat pumps are cost-effective for customers in new construction, but are more expensive than existing gas heating when installed as a retrofit. These findings are consistent with the very few heat pump retrofits completed to date, which are 25 times less than annual rate needed to meet the IEA's net zero trajectory (Amann, Srivastava, and Henner 2021). Heat pumps' challenging economics may change if the price differential between electricity and natural gas tightens due to changing market conditions or regulatory interventions.

One reason heat pumps appear more costly than fossil heating is unpriced greenhouse gases and air pollution externalities. Borenstein and Bushnell (2021) have shown that residential electricity prices exceed social marginal costs to a much greater degree than natural gas prices in most of the U.S.[4] Because electricity prices often recover more fixed costs and are subject to more environmental regulations (i.e., electric-sector carbon pricing in Regional Greenhouse Gas Initiative (RGGI) states) than natural gas prices, electricity is overpriced relative to natural gas for most residential customers. Along these lines, Kaufman et al. (2019) find that economy-wide carbon pricing (i.e., affecting both electricity and natural gas prices) and improvements in ASHP performance can make heat pumps economic in cold climates in the 2030s. Deetjen, Walsh, and Vaishnav (2021) find that by considering the social costs of CO_2 and criteria pollutants (SO_2, NO_x, and $PM_{2.5}$) in addition to operating and investment cost, the share of U.S. homes with today's grid generation mix that benefit from heat pump adoption increases from 32% to 70%. The authors also find that while heat pumps almost always reduce CO_2 emissions, they can increase health damages from criteria pollutants because gas-fired power plants generate more air pollution than gas-fueled residential heaters do per unit of heat. Without additional clean electricity, health damages from heat pumps undermine climate benefits in nearly a third of potential retrofits, according to Deetjen, Walsh, and Vaishnav (2021).

2.2. Heating Electrification Policies

As the climate benefits of heat pumps have become clear and more urgent, policies to accelerate heating electrification have emerged at municipal, state, and federal levels.

[4] Social marginal costs equal private marginal costs plus social externalities, in this case primarily health damages from emissions.

This section summarizes the different kinds of building electrification policies that have been applied across jurisdictions based on Cohn and Esram (2022) and RMI (2021), unless otherwise noted. As discussed further below, four archetypes of policies have emerged: heat pump incentives, heat pump targets, building codes and standards, and regulations for gas utilities.

- **Heat pump incentives** are bottom-up financial incentives that defray heat pump installed costs and are present in 15 states.[5] These incentives are administered by state agencies, utilities, and nonprofits, and most commonly take the form of an end-user rebate targeting single-family residential buildings that currently use natural gas, propane, or heating oil. As programs span from small pilots to full-scale rollouts, the incentive levels vary greatly, ranging from $300-$2,000/ton of capacity or $50-$12,000/system with median incentives of $800/ton and $1,500/system. Most incentives are funded by utility ratepayers through existing energy efficiency programs and encourage customers to also implement weatherization upgrades.
- **Heat pump targets** are top-down installation targets issued by governments to guide electrification efforts. While these goals are usually not legislatively binding, they can serve as a bellwether signaling more aggressive policy implementations to come, such as increased incentives, building codes, and utility regulations. Some targets include Massachusetts' goal of 1 million heat pumps installed by 2030 and Maine's goal of 100,000 heat pumps installed by 2025. The U.S. federal government has also committed to eliminate emissions in federal buildings by 2045.
- **Building codes and standards** have been increasingly used to advance electrification in new construction. Over 54 cities and counties in California have committed to phase out gas in new buildings through all-electric mandates, sometimes known as gas bans (Gough 2021). There are also state-level efforts underway in New York and California to adopt all-electric building codes by 2025 and zero-emissions appliance standards in the 2030s. These policies have attracted controversy and denigration from the gas industry, which has led to 20 states passing preemption bills that prohibit municipal gas bans (DiChristopher 2021b).

[5] AK, AZ, CA, CO, CT, DC, IL, MA, ME, MN, NY, OR, RI, VT, WA

- New **regulations and transition plans for gas utilities** have emerged as several states grapple with the need to decarbonize heating. Regulations can include emissions targets, such as Colorado's Clean Heat Standard which requires gas utilities to cut emissions by 4% by 2025 and 22% by 2030. Other states such as Vermont are considering similar policies that cap emissions for suppliers of heating fuels (NEEP 2022b). In addition, utility commissions in nine states have opened "future of gas" proceedings to investigate stranded asset risks of continued gas system investments.[6]

Efforts to advance heating electrification have gained significant momentum over the recent years, as demonstrated by the scale and scope of policies. However, many adoption barriers remain which require policy solutions if heating electrification is to be achieved at scale.

2.3. Barriers and Opportunities for Heating Electrification

Remaining challenges for heating electrification can be categorized into economic barriers, non-economic barriers, and regulatory challenges. These challenges and opportunities for corrective action are discussed below.

Economic barriers exist if the capital cost and operational cost premium of heat pumps are not offset by available incentives, or if the incentives are not salient to potential participants. The literature on heating electrification economics, including Deetjen, Walsh, and Vaishnav (2021) and Kaufman et al. (2019), typically does not consider existing incentives or the optimal incentive levels to induce electrification. Rate designs that set electricity prices well above marginal costs distort consumer fuel switching decisions, requiring greater upfront incentives for heat pump adoption (Borenstein and Bushnell 2021). In addition, incentives for heat pumps may not be salient to participants such as residential tenants in multifamily apartments or low-income households. Tenants and landlords face a split incentive problem that has been well documented across energy efficiency programs. Reaching these households requires increasing incentives for property owners and raising awareness with tenants. Lastly, energy efficiency rules that prohibit fuel switching still exist in 10 states (Cohn and Esram 2022).[7] These rules require that funds collected from electricity rates only be used for efficiency programs targeting existing electric end uses, and

[6] CA, CO, DC, MA, MN, NV, NY, OR, WA.
[7] AZ, AK, KS, LA, OK, PA, SC, TX, WA, WV.

cannot be used to incentivize customers to switch from natural gas to electricity. Replacing these policies with fuel-neutral energy efficiency rules would unlock additional energy efficiency funds to support electrification in these states.

Non-economic barriers can also hinder electrification in meaningful ways. The infrequent replacement cycle of heating equipment means that there are few opportunities to electrify, unless retrofits become vastly more popular in the future than they have been historically. 85% of HVAC system replacements are done on an emergency basis, and when systems fail, homeowners usually choose a like-for-like replacement because it is the most accessible and affordable option (Pantano et al. 2021). This sequence of events adds up to missed opportunities for electrification that lock in future heating emissions and raise the costs of building decarbonization. Two underlying reasons that explain this pattern are a lack of consumer awareness and a lack of qualified contractors who are comfortable with selling heat pumps. In Massachusetts, there is anecdotal evidence that many HVAC contractors are traditionalists who are averse to recommending heat pumps due to a lack of familiarity or trust with the technology (Zuckoff 2022). Pantano et al. (2021) propose a targeted, temporary federal subsidy to suppliers who manufacture or distribute ASHPs instead of central air conditioners. The authors estimate that such a supply-side program would deploy 45 million new ASHPs nationwide, resolving supply chain, availability, and contractor awareness issues that currently hinder the effectiveness of demand-side incentives.

Lastly, electrification at any meaningful scale will cause regulatory challenges in stranded cost recovery for gas utilities. When heating electrification causes customers to leave the gas system, the remaining fixed costs (both maintenance and capital costs) of the gas delivery system are allocated across a fewer number of customers. This leads to higher bills for remaining customers, which sharpens the incentives to leave, creating in effect a natural gas version of the "utility death spiral". Davis and Hausman (2022) estimate that 40% of residential customers leaving the gas system would cause per-customer gas bills to increase by $115 per year. While such a feedback loop can be beneficial from a climate perspective, it could raise serious equity issues as customers who are unable to adopt heat pumps will be stuck with the burden of cost recovery of legacy gas assets. These equity issues may compound pre-existing equity issues such as who benefits from solar and energy efficiency subsidies and who suffers from local air pollution (Reames 2016). Davis and Hausman (2022) suggest several policy options to address these issues, including

prioritizing electrification of low-income customers, accelerating depreciation schedules for natural gas assets, charging exit fees for disconnecting from the gas system, shifting costs to utility company shareholders, and recovering stranded costs through the tax base instead of the remaining gas ratepayers.

Together, these barriers create several hurdles towards achieving electrification at the scale needed to meet climate goals. Utilities and regulators have important roles to play in enabling electrification through distribution planning and rate design. The following chapter reviews frameworks for regulating utilities in a world with greater DERs such as heating electrification.

3. Regulation of Distribution Systems with Heating Electrification

Heating electrification will dramatically change how buildings use electricity, both increasing the total energy consumed and altering the profile of energy consumption. These impacts can create new challenges for operating electric power systems, which are simultaneously experiencing two major structural shifts: the transition from mostly dispatchable fossil resources to mostly intermittent renewable resources, and the transition from a grid with mostly centralized generation to a grid with more DERs. In this context, heating electrification introduces additional operational and investment challenges, but also presents an opportunity to re-evaluate the regulation of electricity and consider reforms that sharpen incentives for demand-side resources and flexible consumption to provide value to the grid by shifting load and reducing peak demand.

This Chapter presents an overview of distribution system planning and regulatory frameworks, introduces some technical considerations of distribution networks, and summarizes the literature on how heating electrification will affect electricity demand.

3.1. Evolution of Distribution System Planning and Regulation

Electric distribution systems comprise of the poles, wires, and devices that convert electricity from the transmission system and deliver it to end users. These networks are typically planned, maintained, and operated by distribution utilities. As electricity distribution is a natural monopoly, distribution utilities have been subject to different forms of regulation throughout history, including public ownership or direct oversight of pricing by state public utility commissions. Today, distribution utilities remain regulated even in regions where generation and retail are deregulated through electricity markets. To understand how heating electrification will affect distribution systems, it is useful to first review utility planning and regulation principles and highlight how these methods have evolved with the growth of DERs.

Utility regulation involves two primary tasks: determining the total revenue requirement that the utility should recover from end users based on prudent capital and operating expenses (the cost of service problem), and determining how to collect these revenues from end users (the cost allocation or rate design problem) (Jenkins 2014).

In the cost of service problem, regulators seek to ensure that utilities provide electricity to customers reliably and cost-effectively while remaining financially viable. These objectives have

clear tradeoffs: an overbuilt system is very reliable but prohibitively expensive, while an underbuilt system is economical but highly inconvenient. Likewise, a utility that is unable to recover its investments through rates will struggle to raise financing in capital markets and will eventually go bankrupt. Under traditional cost of service (or rate of return) regulation, regulators attempt to balance these tradeoffs by only approving utility expenses that are prudently incurred and setting a "fair" rate of return to appropriately compensate for the utility's opportunity cost of capital. In doing so, they face several regulatory challenges, including incomplete information, the potential for strategic behavior, and moral hazard (Jenkins 2014).

Incomplete information is endemic in utility regulation since only the utility knows its true costs, available opportunities, and how efficiently it conducted its business operations. Moreover, utilities build expensive and long-lived assets, so regulators often have to assess whether these investments are prudent under substantial uncertainties over future conditions. In addition, since utilities earn a return on their capital expenses but operating expenses (e.g., maintenance and fuel costs) are recovered at-cost, they are incentivized to over-invest in capital assets – an age-old concern known as the Averch-Johnson effect (Joskow 2007). Utilities have lucrative opportunities to behave strategically, such as by overestimating future demand or underestimating the contributions of non-capital solutions. Regulators are aware of this problem, so utilities typically face a high burden of proof when proposing new investments or programs. While this protects customers against excessive rates, it also limits the utility's ability and incentives to nimbly innovate or to quickly deploy new technologies. Finally, cost of service regulation presents a moral hazard for the utility: if its revenues are guaranteed based on realized costs, it has no incentive to pursue cost-saving strategies.

In response to these challenges, regulators have increasingly incorporated elements of incentive regulation, such as revenue caps and performance-based rates. When revenues are capped ex ante over a future period, firms earn a return on investment by reducing realized costs below the cap (Joskow 2007). Similarly, tying cost recovery to performance measures such as reliability metrics and customers satisfaction levels can align utility incentives with public benefits and reduce information asymmetry problems for the regulator. However, incentive regulation comes with its own challenges as it is quite difficult in practice to set an appropriate revenue cap and to choose and measure the appropriate metrics.

In the rate design problem, regulators seek to approve "reasonable" public utility rates that allocate the utility's efficiently-incurred revenue requirement across customer types. What is reasonable remains fiercely debated, but principally regulators seek to balance several well-established ratemaking principles: economic efficiency, equity, customer satisfaction, and revenue stability (Hledik, Lazar, and Schwartz 2017). Economically efficient rates reflect the cost of producing and delivering electricity to each customer (i.e., *cost causality*). Rates that accurately signal the impact of consumer behavior on network costs are more temporally and spatially differentiated, and should in theory lead to more efficient network use. Equitable or fair rates have minimal cross-subsidies and apply consistent methods to determine customer bills. In the same vein, customer satisfaction is important and can be achieved through transparent and understandable rates, or through automating technologies that simplify decisions with complex rates. Giving choices to customers can also improve satisfaction by better matching rates with individual risk tolerance. Lastly, revenue stability is important for both the utility and customer: utilities want to avoid under-recovering when rates are not cost reflective, and customers want to avoid unexpected bill shocks. There are inevitable trade-offs in a given pricing model's ability to meet these objectives.

Because visibility into the distribution system is limited and most customers had more or less predictable loads, the industry has traditionally relied on a "fit-and-forget" approach to distribution system planning: utilities would forecast system needs and propose capital investments in distribution infrastructure to meet peak demand with limited involvement from consumers. Because of the discrete nature of network investments, it is difficult to establish cost causality for distribution upgrades. These fixed distribution costs are largely recovered without differentiating for location or timing as a component of volumetric electricity prices for residential customers (Schittekatte 2020).

Heating electrification can have important effects on both cost of service and rate design aspects of utility regulation. Of course, increased electricity demand can overload distribution grids, necessitating upgrades that would increase the distribution cost of service. However, if heat pumps increase total energy consumption within the limits of current grid capacity, volumetric rates would decrease as the revenue requirement would be recovered from a higher denominator of kilowatt-hours, an effect known as "beneficial electrification" (Farnsworth et al. 2018). This can lead to a virtuous cycle where heat pump adoption lowers rates, which further increases adoption

– a reinforcement loop that is the opposite of the "utility death spiral" caused by distributed generation. Heat pumps can also change residential load shapes and require redesigning existing time-varying rates and demand response programs that currently target summer cooling hours to target winter heating hours instead. And as discussed in Chapter 2, heat pump adoption can be further facilitated by resolving inefficiencies in electricity and natural gas pricing by moving volumetric rates closer to marginal costs.

To evaluate the effects of heating electrification on distribution systems, we can draw lessons from recent efforts to integrate distributed energy resources (DERs). DERs are a wide range of technologies with generation, storage, or load shifting capabilities that connect "behind-the-meter" at the customer location. Examples of DERs include distributed solar, combined heat and power, distributed storage, demand response, and energy efficiency. With effective incentives, heat pumps are also a DER that provides flexible load and demand response.

The rapid growth of DERs has disrupted the "fit-and-forget" distribution planning paradigm. Over 78 GW of DERs were installed from 2017 through 2021 in the U.S., which is less than half of the 175 GW that the consultancy Wood Mackenzie projects will be installed from 2022 through 2026 (Hertz-Shargel 2022). Because DERs span many technologies, markets, and use cases, their impacts on distribution systems can be quite different. Sometimes DERs create integration challenges that increase network maintenance and investment costs, such as when excess generation from distributed solar causes reverse power flows. In other cases, DERs provide valuable network benefits by reducing line losses and congestion, providing voltage and reactive power support, and deferring network investments by shaving peak load. DERs still rely on the distribution grid to export electricity and provide grid services, provide power when local generation is unavailable, and maintain grid stability by balancing voltage and frequency. Ultimately, maximizing the benefits of greater DERs requires greater coordination between the distribution utility and end users.

In the recent years, policymakers have made inroads in integrating DERs through cost of service and rate design reforms. To coordinate DERs in utility investment plans, several states have revised resource planning processes to require consideration of non-wires alternatives (NWAs), DER portfolios developed explicitly to defer or replace grid infrastructure upgrades, alongside traditional solutions. Completed NWA projects in New York, California, Michigan, Washington,

Maine, and Rhode Island range in size from a few megawatts to upwards of 100 MW, and have successfully resolved distribution challenges such as feeder thermal constraints and transformer overloading issues at the substation (Chew et al. 2018). In addition to potential cost savings, NWAs offer flexibility to implement solutions incrementally when there is uncertainty in system needs. Instead of building new capital assets into the rate base that may not be needed, NWAs can provide temporary load relief, sometimes at lower cost, until grid needs actually materialize. This optionality is highly valuable in the case of electrification, as the potential system needs can be substantial but where and when they will materialize is highly uncertain. If the NWA solution performs adequately and is more cost-effective than the infrastructure upgrade, the program can be extended to lock in cost savings. As many NWAs have been the result of top-down regulatory mandates, fully realizing the potential of NWAs requires aligning utility investment incentives (Chew et al. 2018). New York allows utilities to earn a rate of return on NWA projects plus a bonus based on performance, which has led to a wave of utility-led NWA procurements that met distribution needs at lower cost than conventional equipment upgrades (New York PSC 2017). These efforts have been complemented by more cost-reflective rates for DERs implemented through New York's Value Stack policy, which replaces net energy metering (NEM) with hourly prices that vary by location (NYSERDA 2020). Under the Value Stack, DERs earn revenues proportional to the energy, capacity, environmental, and locational value of their generation on an hourly basis. These price signals coordinate DER operations and investment to areas of the grid where their grid services are most valuable. Outside of hours when NWA projects are needed to meet a specific distribution need, they can earn revenues from distributed generation, which improves project economics and results in greater deployments. New York's experience and relative successes with DERs highlight the importance of closely integrating the resource planning and rate design aspects of utility regulation, lessons which should be applied to other jurisdictions.

Similar to distributed solar and other DERs, heating electrification can potentially disrupt distribution planning and regulation through substantial impacts in energy and peak demand. The regulatory approach to promote cost-effective electrification involves many of the same ingredients for success as DER integration: full consideration of the inherent flexibility in new sources of demand, the importance of cost-reflective rates as a signal for efficient consumption patterns, and continued regulatory innovation to leverage the flexibility of DER solutions in meeting evolving grid capacity needs.

3.2. Technical Considerations of Distribution Networks

Reliable operation of distribution networks requires continuously meeting demand while ensuring power quality, voltage quality, and safe equipment limits. This is important because distribution networks account for over 90% of all service interruptions in the United States (Eto et al. 2019). These outages lead to massive economic losses of $80 to $100 billion per year (Larsen et al. 2018). Electrification increases public dependency on reliable power supply, and thus it is important to establish the technical factors to consider when evaluating heat pump impacts on distribution grids.

Distribution networks generally begin with one or more distribution substations that step-down voltage from the transmission level to a series of medium and low voltage feeders which connect end users.[8] Most residential and small commercial customers connect to the distribution system at low voltage levels, while larger commercial and industrial customers connect directly to medium and high voltage networks. Table 1 lists typical ranges for transmission and distribution voltages in the U.S.

Table 1: Nominal Transmission and Distribution Voltages in the U.S.

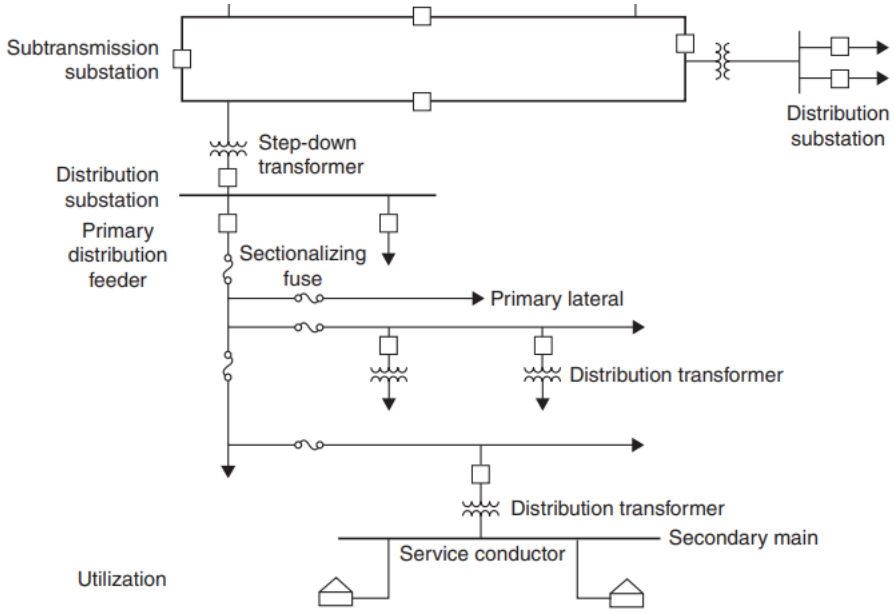
	Voltage Level	Nominal Voltage
Transmission	High Voltage (HV)	> 138 kV
Subtransmission	High Voltage (HV)	69 kV to 138 kV
Primary Distribution	Medium Voltage (MV)	2.2 kV to 46 kV
Secondary Distribution	Low Voltage (LV)	120 V to 480 V

Source: Glover, Sarma, and Overbye (2012)

Each voltage level can be designed and operated in meshed, loop, or radial configurations. In the United States, meshed and loop feeders are more common in high-density urban areas, where they are built underground for greater reliability. Overhead radial feeders are widely used in low-density suburban and rural areas because they are more cost-effective to build and maintain. Figure 2 illustrates the layout of a typical distribution system with radial feeders.

[8] This section draws upon (Glover, Sarma, and Overbye 2012), (Bharatkumar 2015), and (Huntington 2016).

Figure 2: Layout of a Typical U.S. Radial Distribution System



Source: Glover, Sarma, and Overbye (2012)

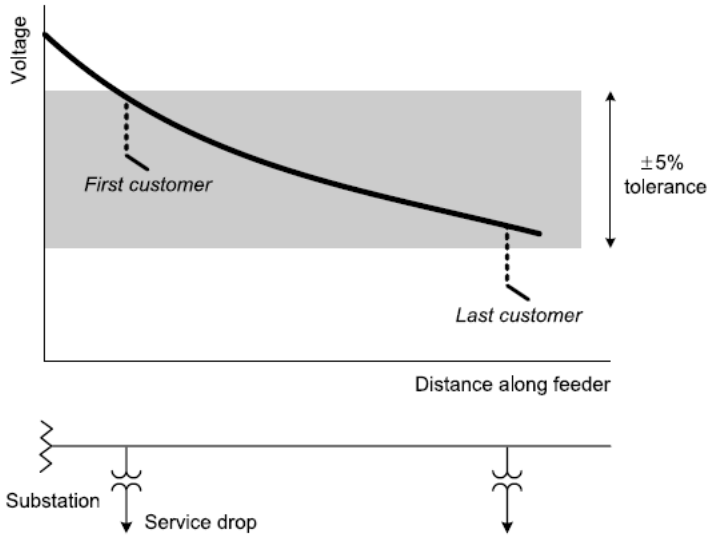
The transformer at the distribution substation steps down the voltage from HV to MV. The distribution network continues to a primary feeder which branches into primary phase laterals and secondary feeders connected by MV-LV distribution transformers. Each substation typically supplies several feeders. Protection devices such as sectionalizing fuses and automatic reclosing devices are distributed throughout the network to isolate faults and minimize customer service interruptions.

From an operational perspective, reliability in distribution networks means continuously meeting demand while respecting equipment capacity limits and voltage limits. The most relevant capacity limits for distribution systems apply to distribution lines and transformers. Distribution lines face thermal limits due to resistive heating in the conductor (Meier 2006). As demand increases, more current flowing through a line is dissipated as heat, causing the conductor to stretch from thermal expansion and the line to sag, eventually leading to equipment damage. Line ratings dictate how much power can safely flow through a line and vary based on ambient conditions, as more heat can be dissipated when temperatures are colder. Transformers are devices that change the voltage in an AC circuit using electromagnetic induction, and similarly face thermal limits due to resistive losses. Large transformers regulate heat by circulating oil through the core and windings. When they are overloaded, internal temperatures rise and the oil may break down or even burn, causing

an explosion. When lines or transformers become overloaded due to load growth, the typical distribution upgrade is to install additional equipment with higher capacity ratings, such as adding a parallel line or a larger transformer.

Voltage is tightly controlled throughout the generation, transmission, and distribution systems. The exact voltage level at each location of a network depends on the amount of reactive power generated or consumed locally, and the amount of voltage drop due to resistive losses along the line (Meier 2006). In radial distribution systems, the voltage drop effect is usually the more important issue. In the U.S., utilities need to maintain voltage for all users along a feeder within a +/- 5% tolerance of the nominal voltage. For example, a customer receiving 120 V should expect to measure between 114 and 126 V at their location at any given time. The voltage drop is illustrated in Figure 3. The first user closest to the substation has the highest voltage and the last user furthest from the substation has the lowest voltage; the total voltage drop increases with greater distance and greater load. When voltage issues arise, load tap changers and voltage regulators can be installed to maintain voltage within acceptable levels.

Figure 3: Illustrative Voltage Drop Along Radial Distribution Feeder



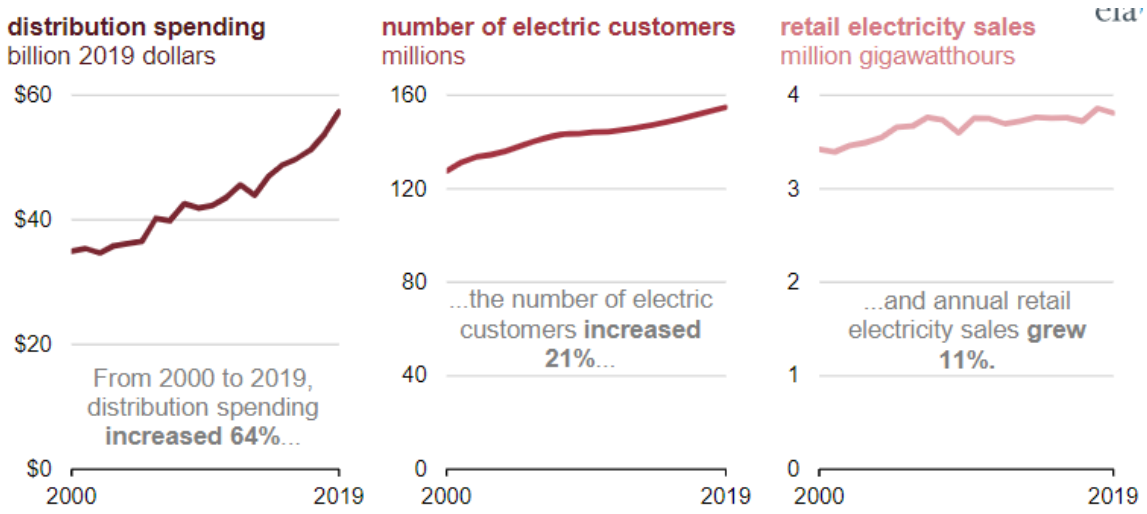
Source: Meier (2006)

Because heating electrification will increase demand, the resulting distribution issues primarily involve the potential for overloading transformer and conductor capacities and increasing voltage drop beyond acceptable tolerance levels. Beyond like-for-like equipment upgrades, distributed energy storage through batteries can also alleviate distribution issues by shifting load from peak

hours to off-peak hours, and distributed generation from rooftop solar can also help support voltage and capacity limits.

In the United States, total utility spending on distribution systems has grown at a faster rate than customer growth and demand growth, as shown in Figure 4. Utilities explain that this higher spending level is necessary to replace aging equipment that is well beyond its useful economic life and modernize grid infrastructure. Some investments, such as advanced metering infrastructure (AMI), are needed to appropriately compensate DERs and induce demand flexibility. These trends have contributed to energy delivery costs growing as a share of total customer bills, which has drawn regulatory scrutiny on what investments actually are prudent. As electrification efforts scale up across the U.S., regulators will need to balance public policy goals with likely additional requests from utilities to increase distribution spending in response to electrification impacts.

Figure 4: U.S. Electric Distribution Spending, Customers, and Sales, 2000-2019



Source: US EIA (2021)

3.3. Literature on Heating Electrification Load Impacts

As electrification has grown to become a popular decarbonization strategy in the past several years, so too has the academic and industry literature on its impacts. Here, we focus on major studies of heating electrification and highlight their methods for analyzing load shape and distribution system impacts.

Two major research efforts have studied the impacts of multi-sectoral electrification.

- In NREL's Electrification Futures Study, Mai et al. (2018) use a bottom-up stock rollover model to estimate the effects of transport, building, and industrial electrification on U.S. energy demand through 2050. The authors project annual sales shares of electric technologies, which informs equipment stocks used to calculate final energy use. They model 40% and 61% space heating electrification in 2050 under Medium and High cases (~60 million and ~100 million heat pumps deployed, respectively). They calculate electricity consumption from total service demand and equipment efficiency, and use regressions trained on building simulations and weather data to develop hourly heating load shapes that vary by location. Because efficient heat pumps replace some inefficient resistance heaters, the authors estimate only small increases in residential electricity consumption. The authors estimate that multi-sector electrification will increase peak demand by 19% and 33% in the Medium and High cases, respectively. The authors find that heat pump adoption in cold climates like the Midwest and Northeast lead to significant shifts in load shapes, and that in the High case Northeast regions become winter peaking by 2050. Zhou and Mai (2021) extend the prior work to assess the operational aspects of power systems with high electrification, high variable renewables, and high demand flexibility. The authors find that flexible load can enhance the ability of electrification to decarbonize the power sector by matching consumption to renewable generation patterns, in addition to providing grid services during periods of system stress. They estimate that demand flexibility can lower production costs by 9-10%.
- In Princeton's Net-Zero America Report, Larson et al. (2021) use essentially the same methodology but add a constraint of net-zero emissions by 2050. The authors develop top-down scenarios of technology transitions needed in each sector of U.S. economy to meet this emissions constraint. The authors model heat pumps in 54% and 80% of residential housing stock in 2050 under their low and high electrification cases (80 million and 120 million heat pumps deployed, respectively), slightly higher than what is contemplated in Mai et al. (2018).

These macro-energy system studies are helpful to understand the scale of transformation needed to reach climate and electrification objectives, but tell us little about the impacts of heating electrification on local distribution systems. Other researchers have analyzed heat pump impacts using building simulation models. As described below, these models use building construction

characteristics and weather data to size heating equipment and calculate its hourly operations and energy consumption profiles. This allows for building and feeder-level analyses of heat pump impacts.

- Deetjen, Walsh, and Vaishnav (2021) analyze economic and health effects of heat pump adoption in 55 U.S. cities. They feed housing characteristics from NREL's ResStock database into the EnergyPlus building energy model to calculate the hourly impacts of heat pumps, which they then use to estimate economic and emissions outcomes. The authors find that the grid impacts of heat pumps can be problematic in colder cities at high levels of adoption. Specifically, they find that at 100% heat pump adoption peak residential electricity demand more than doubles in 24 studied cities (representing 44% of U.S. housing stock) located in cold climates. The remaining cities see manageable grid impacts, as peak demand increases by 50% or less, and in some cases decreases due to the higher cooling efficiency of heat pumps over existing air conditioners.
- White et al. (2021) use the same approach to analyze the impacts of full residential heat pump adoption on the Texas transmission grid across three heat pump efficiency scenarios. They find that because heat pumps reduce summer demand and increase winter demand, annual electricity consumption stays roughly the same or decreases up to 11% with higher efficiency heat pumps. However, heat pumps increase peak demand by as much as 9 GW (25% above base summer peak), pushing Texas residential loads from summer peaking to winter peaking despite the warm climate. The authors estimate a peak demand impact of 2.84 GW per 1 million heat pumps.
- Protopapadaki and Saelens (2017) combine a building energy model with power flow simulations to study the impacts of heat pump and solar PV on Belgian low-voltage (230/400 V) secondary feeders. Building upon methods developed by Navarro-Espinosa and Mancarella (2014), the authors use a Monte Carlo approach to create residential buildings with varying geometry, insulation, and occupancy profiles and feeders with varying size and cable types. They find that heat pumps have a greater line loading and voltage impacts on the studied feeders than solar PV, and that rural feeders are more prone to these problems than urban ones. In their analysis, cable overloading can be expected from 20-30% heat pump adoption, while voltage problems start at slightly higher percentages.

- Instead of using a building thermal model, Waite and Modi (2020) analyze the peak load implications of heat pump adoption for all U.S. census tracts with a temperature-based statistical model of household electricity and fossil fuel demand. They estimate that full electrification would increase non-coincident peak demand (NCP) by 506 GW (a 70% increase), and 25 states would see NCPs double.[9] In New England, they estimate that NCP nearly triples from 24 GW to 70 GW, but in Texas NCP is unchanged. The authors find that 53% of space heating energy demand can be electric without exceeding current peak loads, and that allowing fossil fuel supplemental heat can increase this to 97%. If heat pump technology improves to meet U.S. Department of Energy performance targets, the authors estimate that the NCP increase could be reduced from 506 GW to 120 GW.

Some takeaways from this review include: (1) 50% to 80% heat pump adoption is needed to meet 2050 net zero emissions targets, (2) heat pumps can push cold climate grids to winter peaking above 50% adoption and warm climate grids to winter peaking near full adoption, and (3) heat pump effects on annual electricity consumption are mixed and new demands from heating can be offset by energy savings from replacing inefficient air conditioners and resistance heaters.

While heating electrification has been extensively studied in various ways, there remain some gaps in the literature. Large-scale studies of electrification typically only examine heating impacts on annual energy and peak load. Heating-focused electrification studies often use building simulation models to estimate peak load and load shape impacts, but few analyze local grid impacts using power flow simulations. Protopapadaki and Saelens (2017) use building energy modeling and power flow simulations, but focus on low voltage secondary feeders and do not consider flexibility in heat pump demand. This thesis aims to address these gaps by combining high-resolution building optimization models with power flow simulations to assess the impacts of heat pumps under different rate designs.

[9] Non-coincident peak (NCP) in this context refers to the summation of individual census tract peaks, irrespective of when they occur.

4. Simulating Heating Electrification on a Residential Distribution System

Widespread adoption of heat pumps is an essential part of deep decarbonization efforts, but the implications for distribution systems are somewhat understudied, as discussed above. In this thesis, a modeling framework is developed to inform the following research questions: (1) what are the impacts of heat pumps on household electricity demand, (2) what kinds of distribution issues occur at different levels of heat pump adoption, and (3) to what extent can rate design reshape heating demand to mitigate these grid impacts. We focus on a case study of residential air source heat pump adoption on an illustrative distribution network representative of Massachusetts, a cold-climate region that has high heating demands and aggressive electrification policies, though the methods developed are applicable to other jurisdictions.

This chapter describes the modeling process, scenario definition, and modeling results.

4.1. Overview of Modeling Process

Our approach combines a building and DER optimization model with a power system analysis tool to analyze how a realistic distribution network responds to heat pump adoption by a diverse set of residential buildings. This extends methods used by Protopapadaki and Saelens (2017) to analyze heating electrification effects on European low-voltage feeders to a U.S. medium-voltage distribution network. In addition, we investigate the ability of flexible demand to lower distribution peak impacts and relieve distribution constraints. This is important because many researchers, including Zhou and Mai (2021) and Satchwell et al. (2021), have shown that the thermal capacity of buildings can offer significant demand flexibility to support bulk grid operations and defer or avoid local infrastructure upgrades.

The modeling process proposed in this thesis consists of two parts: first, we characterize the impacts of heat pumps on building-level electricity demands, and second, we analyze how these building demand profiles affect the technical operations of the local distribution network. The key steps in the process are outlined below and further described in the remaining chapter:

1. Model selection and configuration
2. Define electrification and tariff scenarios
3. Prepare residential building and distribution network models
4. Simulate residential energy consumption with and without heat pumps

5. Populate distribution network with building load profiles
6. Run power flow analyses to identify distribution problems and reinforcements needed

4.2. Model Selection and Configuration

Our approach combines a building optimization model with a power system analysis tool.

We use the MIT Energy Initiative's Distributed Energy Consumption in Actively Responsive Buildings (DECARB) model to assess the impacts of heat pumps on building energy consumption. DECARB is an optimization model that simulates investment and operations of building energy resources. It minimizes a building's total energy costs by scheduling the dispatch of DERs and thermal appliances, subject to constraints on energy balance, equipment operations, and occupant comfort. The outputs of DECARB include hourly profiles of energy consumption and economic results such as operating costs, investment costs, and emissions. DECARB was initially developed as the DR-DRE[10] model and has been used by Unel et al. (2021), Lee (2019), Yee (2017), and Huntington (2016) to analyze building and consumer decisions relating to DERs. The mathematical formulation of DECARB, which is described in detail in Huntington (2016) and Yee (2017), is beyond the scope of this thesis. To ensure building heat meets occupant comfort constraints, DECARB implements a building thermodynamics model which is further described in Yee (2017). As this thesis is focused on the operational impacts of heat pumps, we turn off the investment decision module and only allow DECARB to optimize the dispatch of a building's heating systems based on heating requirements and energy prices.

To run power flow analysis, we use the open-source power system analysis tool Pandapower, introduced in Thurner et al. (2018) and maintained by researchers at University of Kassel and Fraunhofer Institute for Energy Economics and Energy System Technology. Pandapower provides methods for power flow and optimal power flow, among other power systems calculations, according to IEC 60909.[11] Solving a non-linear set of AC power flow equations for the network is required to calculate the voltage drop and thermal loading on transformers and conductors, which are the primary distribution issues of interest. There is no analytical, closed-form solution for these power flow equations, so one must use numerical approximations such as the Newton-Raphson

[10] DR-DRE stands for Demand Response and Distributed Resource Economics
[11] IEC 60909 is an international engineering standard applicable to circuit calculations in low-voltage AC systems.

method. The mathematical formulation is well-known and described in Glover, Sarma, and Overbye (2012) and Meier (2006), and therefore will not be discussed herein.

Massachusetts serves as a good case study because there are significant efforts to decarbonize residential heating and reduce natural gas consumption. The state has a goal of 1 million heat pumps installed by 2030 (Shankman 2021), and offers rebates of up to $15,000 per home to encourage heat pump adoption (Mass Save 2022b). In addition, several cities have tried to ban gas connections in new homes (DiChristopher 2021a), and the utility commission is investigating transition plans for gas utilities in a net zero emissions future (MA DPU 2022). While these efforts may not transform heating overnight, heat pump uptake in Massachusetts is likely to materialize in ways that could cause concerns for distribution utilities, as the literature has established that grid impacts of heat pumps are greatest in cold climate regions.

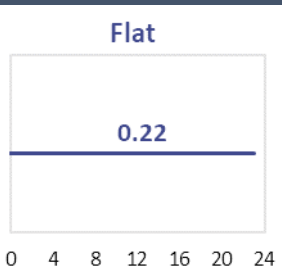
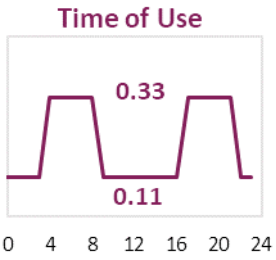
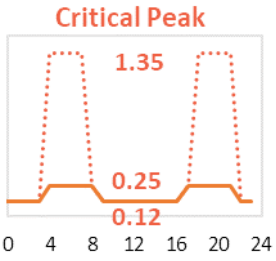
This thesis analyzes heating demands using 2018 Actual Meteorological Year (AMY) weather data from the Boston Logan International Airport sourced from the National Solar Radiation Database (NSRDB). It is important to use AMY data for this analysis rather than Typical Meteorological Year (TMY) data because buildings and heating equipment are designed to meet peak heating needs. TMY data miss extremes and are likely to underestimate the demand impacts of heat pump adoption. We select AMY data from 2018 because this year had high winter heating demands due to the December 2017 – January 2018 polar vortex. We choose to model a case that may appear extreme for two reasons. First, we are interested in understanding the challenges that heat pumps pose to distribution systems under difficult but plausible conditions. While climate change generally leads to shorter winters, there is evidence that brief but intense cold periods are becoming more common (Kretschmer et al. 2018). Since both heat pumps and distribution grids must be designed to meet uncertain future peak demands, 2018 is a reasonable design year for this analysis. Second, heat pumps will be a new heating technology for many Northeast homes, and we assume that most adopters will require that heat pumps meet or exceed the capabilities of fossil heating being replaced.

4.3. Defining Electrification and Tariff Scenarios

We developed four scenarios to assess the household electricity demand impacts of heat pumps across rate designs. These scenarios are implemented as inputs to DECARB, which the model considers in its optimization to meet building energy requirements at least cost. The scenarios vary

across heat pump adoption rate assumed, HVAC equipment, and applicable electricity tariff, as shown in Table 2.

Table 2: Summary of Electrification and Tariff Scenarios

Scenario	Adoption Rate	HVAC Equipment	Electricity Tariff ($/kWh)
Base	0%	Existing furnace or boiler (natural gas / heating oil), existing electric air conditioner	
Elec	10, 25, 50, 100%	Cold-climate air source heat pump (22 SEER, 11 HSPF) sized to fully meet heating needs.[12]	
Elec TOU	100%		
Elec CPP	100%		

First, we model a Base case where the building continues to use existing fossil heating and air conditioning systems under a flat electricity tariff of $0.22/kWh. Because DECARB calculates energy consumption to meet occupant comfort constraints, it is important that the heat pump provides the same quality of heating and cooling for each building as in the Base case. Since heat pumps provide both heating and cooling, we assign a 15 SEER air conditioner to any building

[12] HSPF (Heating Seasonal Performance Factor) is the total space heating required during the space heating season, expressed in Btu, divided by the total electrical energy consumed by the heat pump system during the same season, expressed in watt-hours.

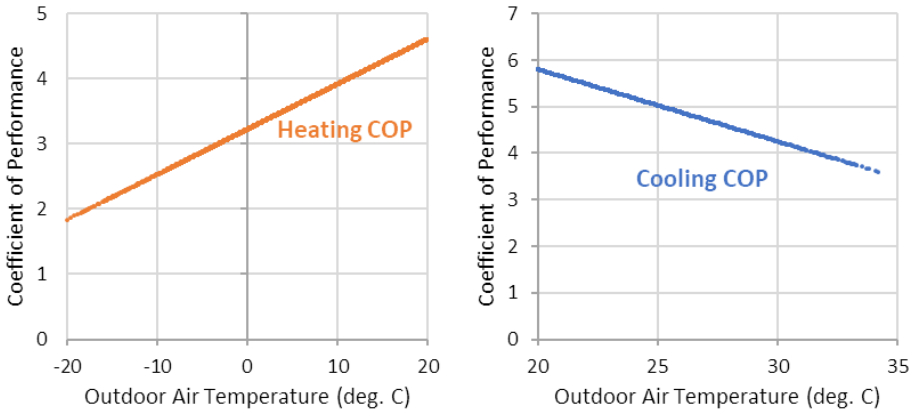
SEER (Seasonal Energy Efficiency Ratio) is the total heat removed from the conditioned space during the annual cooling season, expressed in Btu, divided by the total electrical energy consumed by the air conditioner or heat pump during the same season, expressed in watt-hours.

without one (the minimum for current Energy Star ratings). The flat tariff of $0.22/kWh is based on average generation and distribution charges for Eversource and National Grid residential customers in eastern Massachusetts.[13] These charges are the focus of our rate design exercise because we seek to use price signals to alleviate heating-related distribution system peak demands, and there is well-established regulatory precedent for utilities to recover generation and distribution costs through time-varying rates such as time-of-use tariffs (Faruqui, Hledik, and Sergici 2019). We ignore monthly fixed charges and other volumetric charges (e.g., transmission, energy efficiency, distributed solar, etc.) because we assume these costs are constant and must be recovered under any rate design.

In all electrification cases, we replace existing heating and cooling systems with a cold-climate air source heat pump sized to fully meet the building's heating and cooling needs. We model a high-performing heat pump rated 22 SEER, 11 HSPF; while this is on the higher end of heat pumps commercially available today, it is the minimum efficiency eligible for Massachusetts' Mass Save heat pump rebate program (Mass Save 2022a). Some heat pump systems installed today rely on electric resistance heating to provide supplemental heat. Because we size the heat pump to meet peak heating needs, the modeled heat pumps have no need for supplemental heat. This is a simplifying assumption that could be improved in the future with better data on heat pump sizing decisions. We account for the temperature-dependence of heat pump efficiency using linear heat pump performance curves, similar to Waite and Modi (2020). We specifically assume a linear relationship between the heat pump's coefficient of performance (COP) and the difference between the internal setpoint temperature and external temperature. We estimate this relationship from manufacturer specifications for similarly rated heat pumps in the Northeast Energy Efficiency Partnership's cold-climate heat pump database (NEEP 2022a). The resulting heat pump performance curves for heating and cooling are depicted in Figure 5. We assume that the internal setpoint temperature is set as a range between 18 and 22 degrees Celsius for all seasons and times of day.

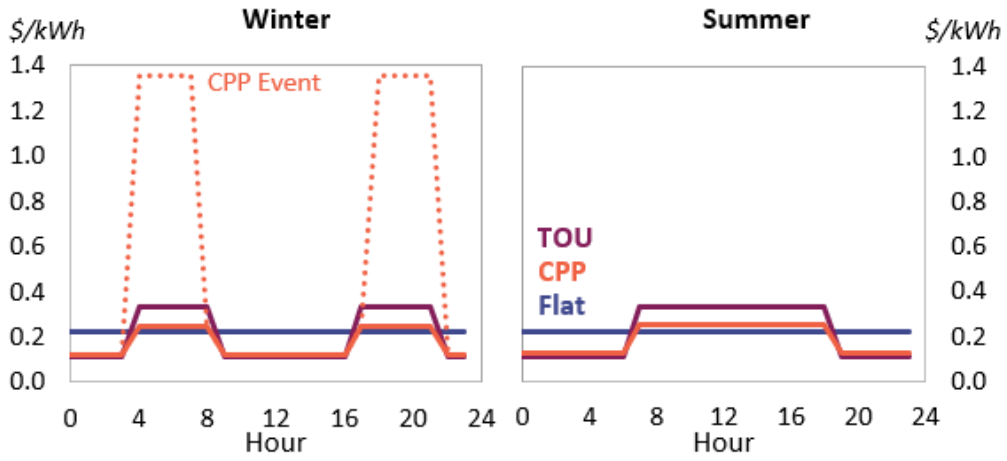
[13] $0.22/kWh estimated as the average of $0.218/kWh and $0.228/kWh, the sums of basic service supply charge and distribution charge under Eversource's R-1 rate effective January 1, 2022 – June 30, 2022 (Eversource 2022) and National Grid's R-1 rate effective November 2021 – April 2022 (National Grid 2021).

Figure 5: Heat Pump Performance Curves



Next, we develop time-of-use (TOU) and critical peak pricing (CPP) rates that aim to reduce the peak demand impacts of heating. These rates are depicted in Figure 6. We design these rates to be revenue-neutral compared to the flat rate, which is a standard ratemaking practice to limit cross-subsidies in new rate designs that can be perceived as inequitable (Hledik, Lazar, and Schwartz 2017).

Figure 6: Electricity Tariff Scenarios

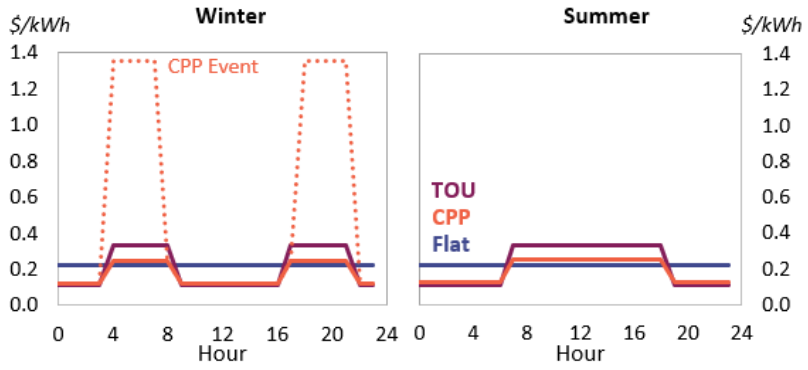


We develop a TOU rate using a 3:1 price ratio between on-peak and off-peak rates, which is a common design for TOU rates across the country that balances consumer acceptability and price response (Faruqui, Hledik, and Sergici 2019). We use substation-level demand in the Elec_100 (100% heat pump adoption under flat rate) scenario to inform the summer and winter TOU periods. For the winter season (October through May), the on-peak hours are two 5-hour peak periods from 4:00 AM to 9:00 AM and 5:00 PM to 10:00 PM, which correspond with when substation-level

demand is highest in the Elec_100 case. For the summer season (June through September), the on-peak hours are from 7:00 AM to 6:00 PM.

We also develop a CPP rate based on Hydro-Québec's "Rate Flex D" plan, a opt-in CPP rate for their electric heating customers (Pelletier and Faruqui 2022). Rate Flex D has a price ratio of 12:2:1, which creates a substantial economic incentive to reduce consumption during critical peak events. This rate was initially piloted to customers in from 2019-2020; after achieving high popularity with customers and significant load reductions, it was rolled out full-scale on an opt-in basis in 2022. We design a similar CPP rate that has a price ratio of 11:2:1, following a ratemaking approach used in Faruqui and Castaner (2020) that assumes critical peak events recover 25% of per-customer revenue requirement. Furthermore, we assume that critical peak events are limited to 100 hours per year, and that each event must occur in the prescribed windows of 4:00 AM to 8:00AM and 5:00 PM to 9:00 PM.

Figure 7: Heating-Focused Rate Designs



We model heat pump adoption of 10%, 25%, 50%, and 100% in the Elec scenario assuming flat electricity rates, and 100% adoption in the TOU and CPP scenarios to assess the extent to which sharper price signals can reduce peak heating demands. Below 100% adoption, we assume that heat pumps are first adopted by buildings that consume the most energy, a rough approximation for income given that heat pumps in New England are still more costly than existing fossil heat (Billimoria et al. 2018).

4.4. Preparing Building and Distribution Network Models

The next steps involve developing representative building models using DECARB, preparing an illustrative distribution network, and mapping building load profiles to locations on the network to analyze the impacts of electrification on power flows.

It is important to capture realistic heterogeneity in the types of buildings on the network so that the electricity demand impacts of heat pumps account for differences in building occupancy and heating requirements. To do so, we adapt high-resolution residential building attributes from NREL's ResStock database, which were developed in Reyna et al. (2021). ResStock has over 600,000 synthetic residential building profiles that represent the 140 million residential units in the United States. These building profiles are available at very high geographic resolution at the Public Use Microdata Area (<100,000 population per area). From ResStock, we filter for residential buildings in Swampscott, MA, a relatively wealthy exurb of Boston that we use as a case study for this thesis. We further filter for only buildings that currently use natural gas or fossil heating, as we focus on the potential distribution issues related to *incremental* heating electrification. We end up with 87 characteristic buildings for which we extract features such as construction data (square footage, age, floors, etc.), existing appliances installed (furnaces, boilers, water heaters, etc.), and building envelope specifications (wall materials, insulation, window area and types, presence of ducts, etc.). ResStock also has hourly occupancy and end-use load profiles developed stochastically using the American Time of Use Survey data developed in Wilson et al. (2022). For each building, we feed the building and occupancy characteristics into individual DECARB models, along with 2018 AMY weather data and the electricity price scenarios described above.

For the distribution network used in this case study, we rely on synthetic distribution system data developed using the Reference Network Model (RNM-US) as part of the Smart-DS project, as described in Mateo et al. (2020) and validated in Krishnan et al. (2020).[14] RNM is a tool that is widely used to develop realistic, large-scale synthetic distribution systems for analytical purposes. Specifically, we extract a suburban medium-voltage network connected to a 16 MW distribution substation from a synthetic distribution model of the San Francisco Bay Area. While we would

[14] The full synthetic distribution system is provided in (Mateo Garcia et al. 2018).

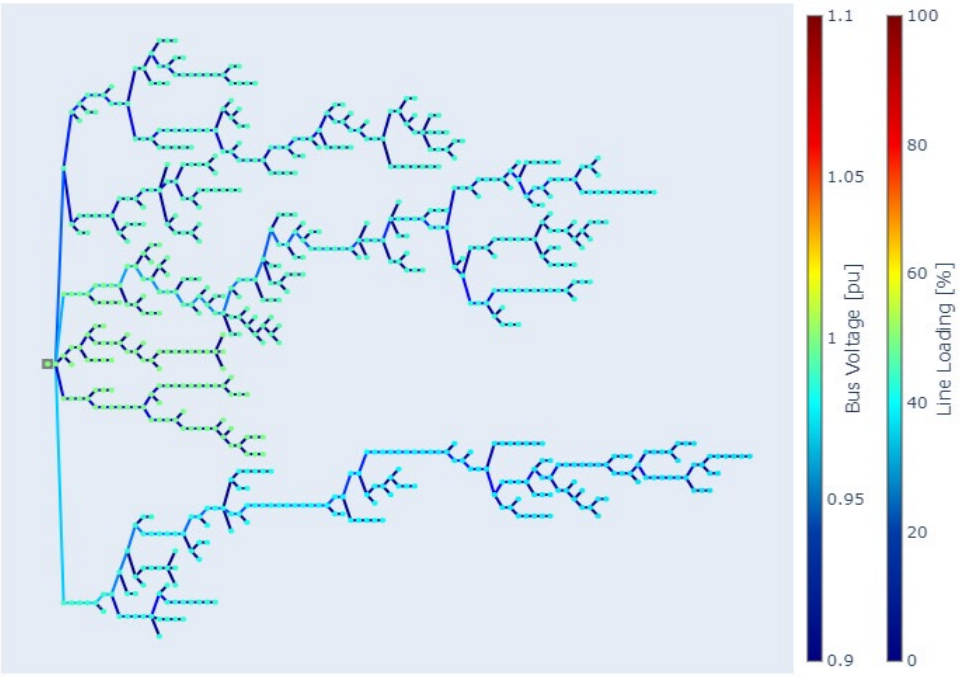
have preferred to model distribution networks in Massachusetts, the lack of timely available data limited our approach. This is alleviated by the observation that suburban distribution systems in the United States are often quite similar across regions (Mateo et al. 2020). The process developed herein could easily be adapted to a different distribution network with available data.

The studied network contains a 16 MVA, 69 kV-to-12.47 kV substation transformer, 54 kilometers of 12.47 kV lines, and 2,826 customers, most of which are residential. The customer peak demand characteristics of the network are shown in Table 3. The substation-level peak load occurs in the summer at 12.56 MW and the initial transformer loading is 85%, indicating that this substation is already somewhat constrained by summer air conditioning loads. The base case power flows and network topology are depicted in Figure 8.

Table 3: Customer Peak Demand Characteristics

	Residential	Commercial	Total
Customers	2,747	79	2,856
Coincident Peak	11.82 MW	0.74 MW	12.56 MW
Average Customer Peak	4.30 kW	9.34 kW	4.44 kW

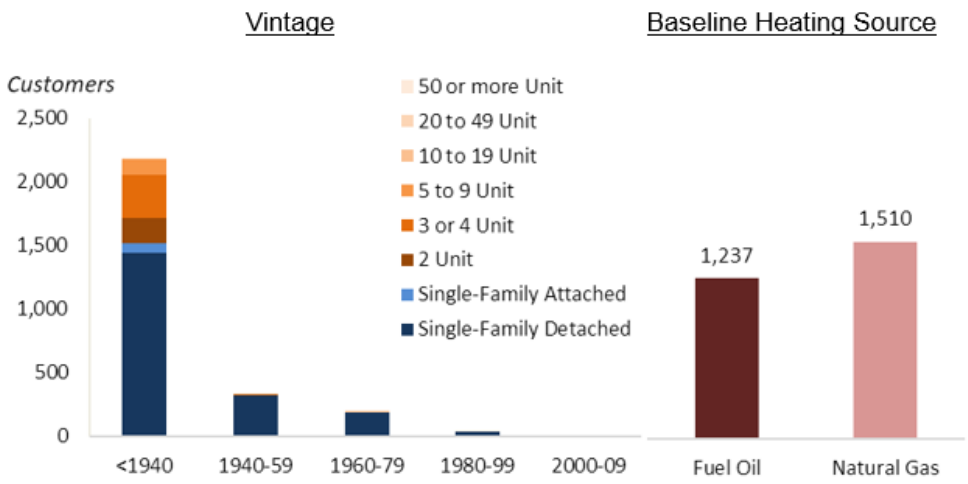
Figure 8: Network Topology and Power Flows, Base Case



The final data processing step is populating the network with DECARB building models. For each customer on the original network, we find the DECARB building model that has the closest peak

demand on an absolute basis and assign this building load profile to the load's location on the network. This method is a necessary approximation given that we are working with disparate building and network data. In the end, we find that 67 of the 87 characteristic ResStock buildings are mapped to at least one customer in the network. This simple customer mapping produces a realistic range of single-family and multi-family building units, construction vintages, and baseline heating sources, as shown in Figure 9.

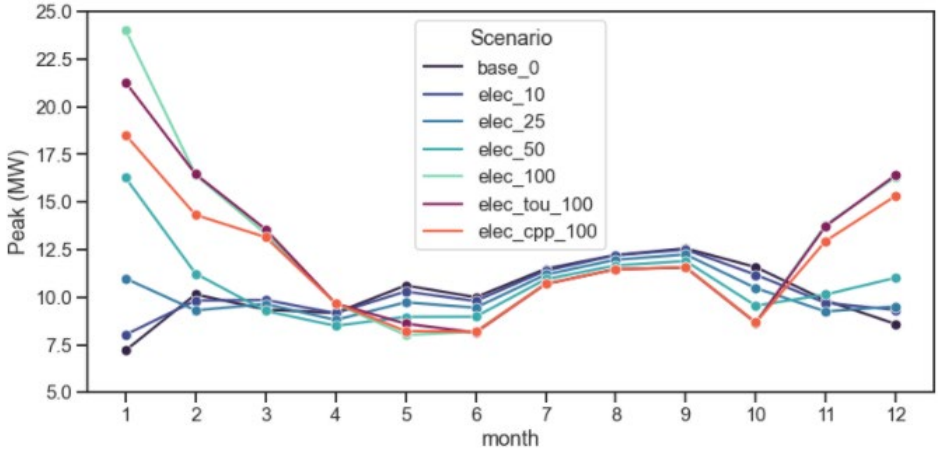
Figure 9: Network Building Characteristics



4.5. Distribution Impacts of Heating Electrification

This section presents that results from the modeling process. We focus on peak demand impacts, load shape impacts, and power flow metrics on the illustrative network due to heating electrification. Figure 10 depicts the monthly substation peak demand across scenarios.

Figure 10: Monthly Substation Peak Demand



The clearest observation is that heat pumps increase winter peaks and reduce summer peaks, shifting the time of peak from afternoon to early morning. In the base case, the 12.6 MW substation peak occurred on September 5, 2018 at 2:00 PM. The initial 10% adoption of heat pumps lowers summer peak demand as the modeled heat pump is more efficient than air conditioners in the base case. The pattern persists at 25% electrification, where we begin to observe winter peak demands rival those of the summer months. It is worth noting that up to this point and until the network becomes winter peaking, heating electrification increases energy consumption while also increasing load factors, as shown in Table 4. This is often known as "beneficial electrification" because the additional energy delivered comes through more efficient use of the existing infrastructure. Beneficial electrification can lower utility distribution rates under traditional utility regulation since the same fixed capital costs are now recovered over greater kilowatt-hours.

We find that this distribution network becomes winter peaking at around 30% electrification. Comparing this to Mai et al. (2018)'s finding that Northeast as a whole becomes winter peaking at around 60% electrification, we see that distribution integration issues could materialize far sooner than bulk system issues. At 50% electrification, peak demand increases by 30% compared to base and exceeds substation rated power (16 MW), and the substation transformer is overloaded by 13%. At 100% electrification, peak demand increases by 91% % compared to base, the substation is severely overloaded and the voltage drop falls outside the 0.95 p.u. design limit. We estimate that under a flat rate, this network can accommodate ~45% electrification without capacity or voltage issues.

We also see that TOU and CPP rates can produce meaningful reductions in winter peak loads. Customer response to the TOU rate lowers winter peak demand by 2.7 MW (11%) compared to the flat rate. The CPP rate produces even larger reductions of 5.5 MW (23%). Table 4 shows that the major issue from the power flow simulations is overloading of the HV-MV substation transformer. The modeled load reductions under the TOU and CPP rates lower transformer overloading by 14% and 28%, respectively. Rate designs that enable demand flexibility can increase heat pump adoption that the current network can accommodate from ~45% to ~50% under TOU rates and ~60% under CPP rates.

Figure 11 and Figure 12 show the chronological substation load in the peak heating week and peak cooling week. It is clear from these figures how heat pump adoption shifts the peak from the

summer late afternoon period to a winter early morning. This is quite a substantial change for residential load profiles which have historically been summer peaking. We also see the ability of the TOU and CPP rates to induce curtailments and shifting of heating from peak hours to non-peak hours. Note that not all buildings are able to contribute to load shifting. Those that are poorly insulated and drafty require continuous heat pump loads during the peak window to meet heating requirements. The amount of load shifting that is possible is a function of how well the time-varying rate is implemented, i.e. whether load response is sufficiently automated through smart thermostats and other enabling technologies, and the thermal capacitance of the building. While further consideration of these factors is beyond the scope of this thesis, Satchwell et al. (2021) offers valuable insights on the path towards "grid-interactive efficient buildings".

Figure 11: Substation Load in Peak Heating Week

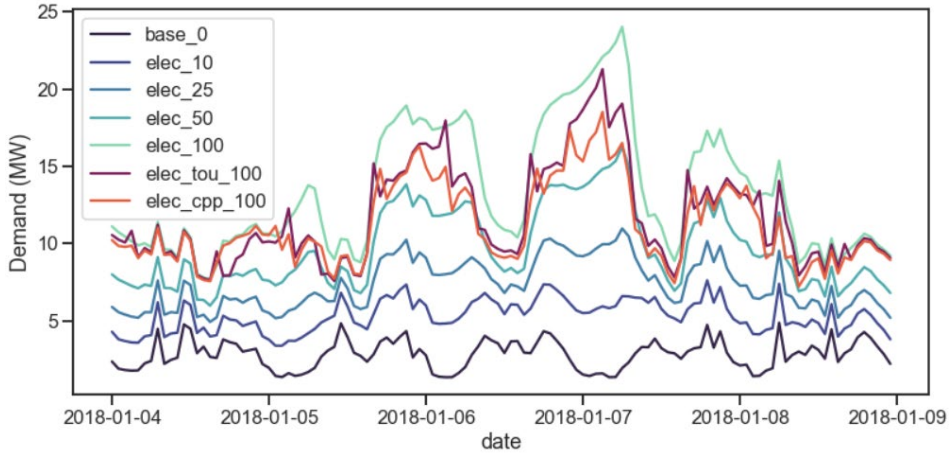


Figure 12: Substation Load in Peak Cooling Week

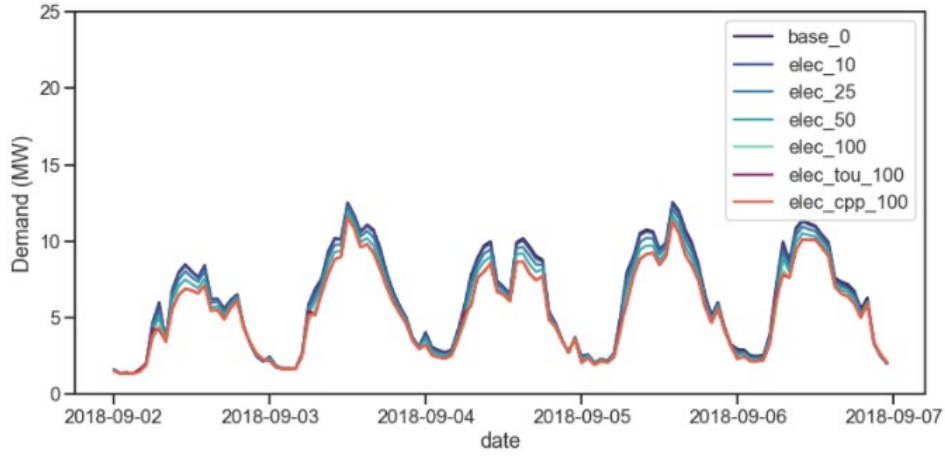


Figure 13 depicts the substation load duration curve. The impacts of heat pumps are apparent through the outward shifts of these curves at higher levels of adoption. What is less clear in this figure but importantly occurs behind the scenes is that the highest load hours are almost entirely in the summer in the base case, but these hours get pushed down the curve by winter heating hours at higher levels of electrification. This "swapping" of hours is why the discernible summer demand reductions from heat pumps are not easily visible in the load duration curves.

Figure 13: Substation Load Duration Curve

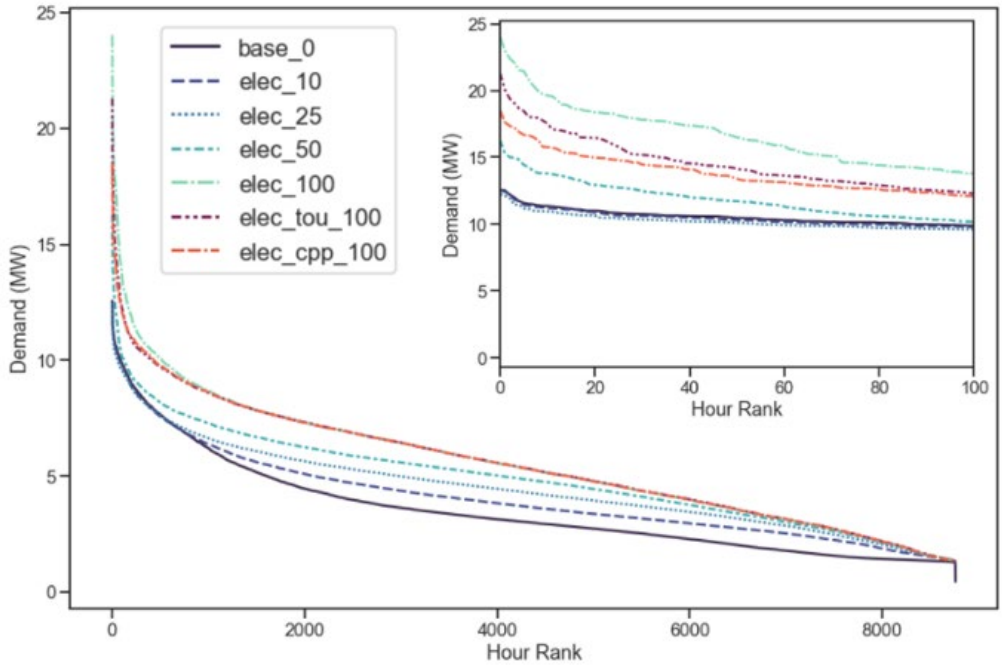


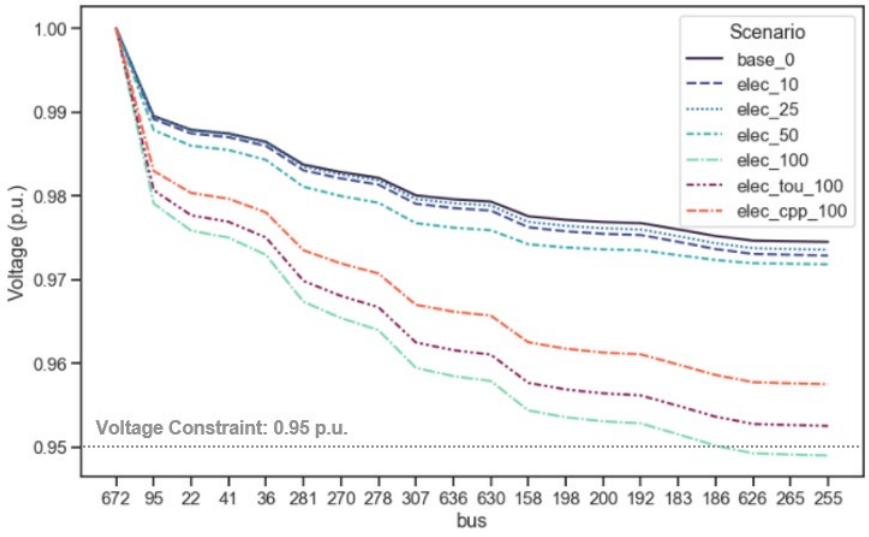
Table 4 shows the detailed results from the power flow simulations. We see that the MV lines on this network are not a limiting constraint in any of the scenarios. While alternative rate designs can lower peak demands, they alone are unable to make this network operable at 100% electrification, and some distribution upgrades or other NWA solutions will be needed. The biggest issue appears to be the substation transformer which experiences overloading above 45% electrification.

Table 4: Load and Power Flow Results

Case	Peak Hour	Peak (MW)	Energy (MWh)	Load Factor (%)	Subst. XF Load (%)	Max Line Load (%)	Min Voltage (p.u.)
base_0	9/5/2018 14:00	12.56	30,651	27.86	85.31	32.52	0.974
elec_10	9/3/2018 12:00	12.50	35,337	32.27	84.95	33.63	0.973
elec_25	9/3/2018 12:00	12.24	38,877	36.25	83.06	32.74	0.974
elec_50	1/7/2018 6:00	16.27	42,711	29.96	113.56	51.32	0.971
elec_100	1/7/2018 6:00	24.02	48,691	23.14	182.53	73.51	0.949
elec_tou_100	1/7/2018 3:00	21.29	48,172	25.83	156.21	63.76	0.953
elec_cpp_100	1/7/2018 3:00	18.52	48,081	29.64	131.84	50.67	0.958

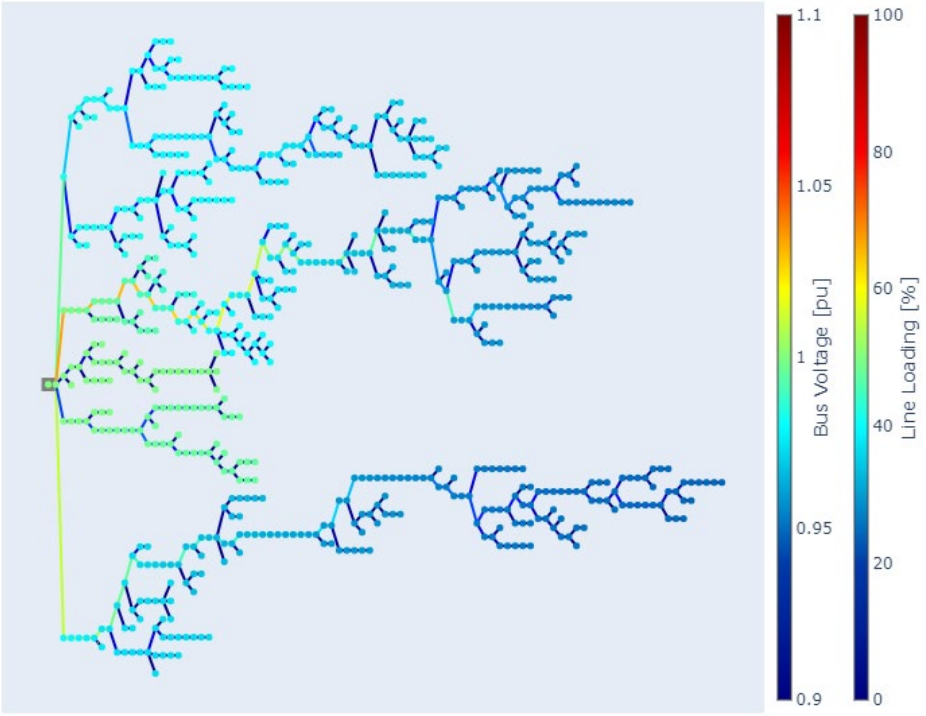
Figure 14 illustrates the voltage drop along the longest branch of the network. Here we see that the under-voltage constraint of 0.95 p.u. is only violated in the Elec_100 case for buses farthest from the substation. However, the minimum voltage in the TOU_100 and CPP_100 cases are also close to being problematic. We also see that on this network under-voltage is likely not an issue at lower rates of electrification.

Figure 14: Voltage Drop Along Longest Feeder



Finally, Figure 15 depicts the power flow results on the network topology in the scenario with greatest distribution issues.

Figure 15: Power Flow Results for 100% Electrification, Flat Rate Scenario



4.6. Heat Pump Integration Costs

In order to quantify the grid reinforcement costs, we need estimates of distribution capacity costs. Distribution capacity costs vary greatly across sources, locations and estimation approaches. We analyzed several cost estimates using both bottom-up and top-down approaches.

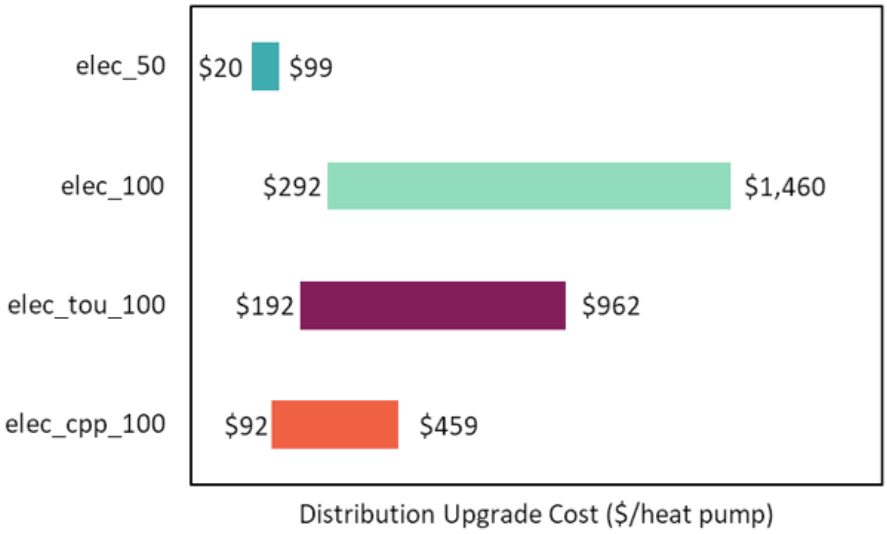
Bottom-up estimates of transformer upgrade costs range from $67–$332/kVA. NREL's distribution cost database estimates transformer installed costs of $95–261/kVA (Horowitz 2019). For interconnecting commercial and industrial customers, Eversource estimates that a typical substation transformer upgrade is $4 million for 60 MVA unit, or $67/kVA, excluding expansion and rebuilding costs (Eversource 2021). In its 100% Residential Electrification Impact Study, the City of Palo Alto estimate that necessary transformer upgrades range from $194–332/kVA.

Top-down estimates of distribution capacity costs range from $150-1,500/kW in marginal cost studies and $100-200/kW in avoided cost studies. Most studies find that marginal distribution costs are highly location-specific. Cutter et al. (2021) show a range from $148/kW in PG&E Mission and $186/kW in Eversource to $1,520/kW in SCE, and assume $400/kW for their analysis of

electric vehicle-related distribution costs. Avoided cost studies for Massachusetts energy efficiency programs use $103/kW for National Grid and $198/kW for Eversource (Synapse Energy Economics 2021). Lastly, Fares and King (2017) analyze historical utility cost filings and report average distribution costs of $40/kW-year, or approximately $400/kW assuming a 10% capital charge rate.

Based on this review, we conservatively assume distribution capacity costs range from $100–$500/kW. We calculate heat pump integration costs by multiplying the capacity cost range by the amount peak demand exceeds the substation capacity limit. Figure 16 depicts the distribution integration costs from the scenarios that require distribution upgrades. In the network studied, we estimate that full electrification under a flat rate requires distribution integration costs of $292–1,460 per residential customer. We see that TOU and CPP rates, that lower peak demand, can meaningfully reduce distribution integration costs to $192–962 per customer and $92–459 per customer, respectively.

Figure 16: Distribution Integration Costs in Constrained Scenarios



4.7. Model Limitations

In interpreting these results, we caveat that our findings are based on simulating an illustrative residential distribution network. Because distribution conditions can vary greatly by location, our analysis is not meant to be representative of all possible heat pump impacts. Instead we show a

plausible set of impacts for a realistic network and describe an approach that can be extended to further location-specific analyses.

We make simplifying assumptions in our modeling process that have implications on our results. In its building optimization, DECARB assumes rational, price-elastic consumers and perfect foresight of future system conditions (weather, prices, heat pump performance, etc.). This assumes that all buildings on the network have advanced meter infrastructure (AMI) and smart thermostats that enable automated demand flexibility. In practice, consumers may not shift consumption in response to time-varying prices as much as we assume. Future research could improve the characterization of consumer response using a utility function.

We also only focus on the impacts from buildings that switch from fossil heating, consistent with heat pump rebate eligibility criteria in many states. Heat pumps that replace electric resistance heating will lower peak demand. Relatedly, supplementing heat pumps with backup fossil or electric heating would lead to lower or higher peak demand impacts, respectively. Lastly, we assume that building insulation does not change with uptake of heat pumps. Better building envelopes would lower peak demand across all scenarios and increase the amount of load shifting possible. Incorporating heat pump systems with supplemental heat and combining energy efficiency upgrades with heat pump adoption are other areas for further research.

5. Discussion and Conclusions

This chapter summarizes the key findings of the modeling efforts and suggests policy implications.

5.1. Summary and Key Findings

This thesis sought to explore the implications of heating electrification on electric distribution systems operations and planning. First, we reviewed heating electrification efforts in the U.S. and opportunities to overcome current adoption barriers. We described how utility regulation and planning has evolved to integrate DERs and how heating electrification could impact power systems. We proposed a modeling framework that simulates the effects of heat pump adoption on a distribution network across different rate designs and presented the associated results. We summarize notable findings from the modeling efforts below.

- **Deployments of residential heat pumps that meet state and federal climate objectives will fundamentally reshape how households use electricity in cold regions like Massachusetts.** Plausible net zero trajectories require 50% to 80% residential heat pump adoption by 2050. Heat pumps both increase winter loads and reduce summer loads, shifting the peak hour from the hottest afternoons to the coldest mornings. Distribution systems can become winter peaking at moderate adoption levels: the tested network becomes winter peaking above 25% adoption under a flat tariff structure.
- **Near-term adoption levels suggest potential for "beneficial" heating electrification.** We observe that heat pumps lower summer peak demand and increase load factors below 25% adoption on the tested network. If this translates to lower capacity obligations and higher retail sales, volumetric electricity rates should decrease, setting off a virtuous cycle for additional electrification. Beneficial electrification can be limited when further adoption causes distribution issues. This exact level is location-specific and depends on how heat pumps are operated. The tested network can accommodate ~45% adoption under flat rates without distribution issues.
- **Long-term target adoption levels may cause various distribution issues.** Above 50% adoption, heat pumps begin to have severe impacts on the tested network. We find that medium-voltage transformers at the substation are the most immediate and most costly investment need. Voltage quality becomes an issue close to full electrification on the tested

network. With a flat rate, full electrification has distribution integration costs of $292 to $1,460 per residential customer.

- **Rate design can reduce peak impacts but the effectiveness of demand flexibility depends on building envelopes and automated participation.** We find that optimal responses to TOU and CPP rates reduce full electrification peak demand by 11% and 23%. These valuable reductions enable a constrained network to increase adoption from ~45% to ~50% under TOU and ~60% under CPP. Well-insulated buildings have the greatest ability to shift heating profiles to reduce local peak impacts. In a future with widespread electric heating, buildings can become distributed thermal batteries, and rate design is the crucial dispatch signal.

5.2. Policy Implications

The findings of this analysis have a number of important implications for utility regulators and policymakers. These are summarized below.

- **Beneficial heating electrification should be a regulatory lodestar and can be aided by three key factors: complementary incentive programs, innovative rate design, and early customer education.** Combining heat pumps with smart thermostats that enable automated controls and tight building envelopes that retain heat can maximize the demand flexibility potential of heat pumps, turning heating electrification from an additional static load to a new distributed energy resource. This can raise the adoption ceiling for beneficial electrification. Unlocking this potential requires empowered rate designs such as critical peak pricing, peak-time rebates, and real-time pricing. Customers must be familiar with the technology and rate options to be willing to participate, so early education efforts to embed the notion of heat pumps as flexible assets are crucial.
- **Advanced rate designs can improve heat pump economics and coordinate "non-wires alternative" load responses to reduce peak impacts.** Innovative rate designs that have a sharp incentive for shifting load can reduce peak impacts. They can also make flexible heat pump systems more economic, lowering subsidies needed to elicit adoption. It is critically important to have the advanced metering equipment (AMI) for time-varying rates installed as early as possible so that customers can get familiar with advanced rates through utility-led pilots. AMI is a long-term investment that unlocks future options for integrating DER

solutions. The Hydro-Québec model is an example of how to gain customer buy-in with advanced rate designs: first introducing TOU rates to build customer familiarity with time-varying rates, then offering a CPP pilot to sophisticated customers, and finally rolling out CPP on an opt-in basis when customers are enthusiastic and already familiar with scheduling heating loads.

- **An efficient path to heating electrification requires aligning utility incentives with societal and public policy objectives.** Utilities have a key role to play in facilitating heating electrification. Regulators should ensure that integrated gas and electric utilities have appropriate incentives to promote electrification. Expanding performance-based ratemaking efforts to include heating electrification targets is one way to align incentives. Since heat pumps can effectively become DERs, reforms that remove utility capital bias by allowing a rate of return on efficiency and non-wires alternatives can pay off in lower distribution infrastructure costs. Regulators should encourage proactive planning efforts such as utility-led pilot programs that combine heat pumps, smart thermostats, insulation upgrades, and innovative rates to familiarize customers with flexible heat pump use. On the other hand, regulators should discourage reactive proposals that confine the public into making investments in conventional infrastructure due to poor planning.
- **Heating decarbonization is an opportunity to correct inefficient policies that weigh down electrification efforts.** Regulators should strive to shift electricity and natural gas pricing closer towards societal marginal costs. In most of the country, natural gas prices are much lower than electricity prices on a per-energy-unit basis due to asymmetric externality pricing and fixed cost recovery. These inefficiencies increase the costs of rebate and incentive programs needed to achieve heating electrification.
- **Deep electrification of heating causes rate pressure on remaining natural gas customers and utilities.** Policymakers should continue to investigate the equity implications of heating decarbonization for natural gas customers and intervene to ensure that gas infrastructure costs are not stranded on customers who are unable to electrify. Developing acceptable transition plans for natural gas utilities can also remove a political roadblock to heating electrification efforts.

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