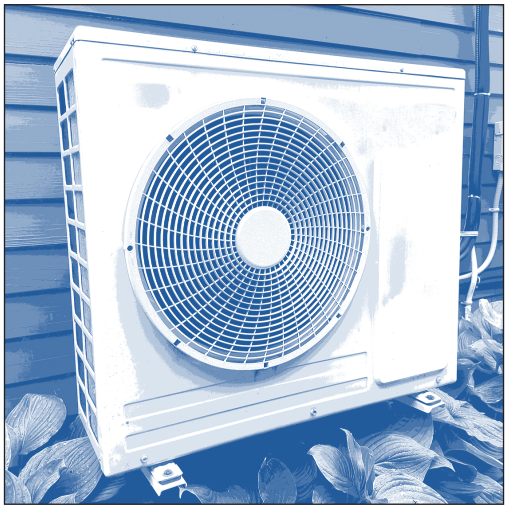
WHITE PAPER

Heat Pump–Friendly Cost-Based Rate Designs

By Sanem Sergici, Akhilesh Ramakrishnan, Goksin Kavlak, Adam Bigelow, and Megan Diehl, The Brattle Group



The economics of heat pumps relative to natural gas heating will be an important driver of customer adoption of these technologies and will determine the extent to which ambitious building electrification goals can be met in a timely manner. If the operating costs for heat pumps turn out to be favorable compared to the operating costs for natural gas equipment, it is possible to see a significant uptake of the heat pumps even before the technology cost declines. In this white paper, we examine the role of alternative "cost-based" and "cost-reflective" electricity rate designs in improving the economics of heat pumps by reducing their operating costs. We use a proprietary dataset of gas and electricity usage for 80 single-family residential customers of a large investor-owned utility for modeling customers' electric and gas heating bills before and after electrification. We find that the operating cost gap is positive for all 80 customers under the default electricity rate (energy costs for operating the heating equipment are higher post-electrification). However, moving to one of the three alternative rates flips all 80 customers from a positive cost gap to a negative cost gap, in which energy costs for operating the heating equipment are lower post-electrification.

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

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Contents

About the Authors

Sanem Sergici is a Principal, Akhilesh Ramakrishnan and Goksin Kavlak are Associates, and Adam Bigelow and Megan Diehl are Research Analysts with The Brattle Group. The views expressed here are their own.

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The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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Introduction

Residential and commercial buildings consume large amounts of energy for cooling, heating, and lighting needs. In the U.S., the building sector has been contributing roughly 30 percent of total greenhouse gas emissions. According to a recent United Nations report, the building sector was responsible for 38 percent of CO_2 emissions globally in 2019 (UNEP/GABC, 2020). Given the magnitude of building sector emissions, the decarbonization of this sector, mainly through heating electrification using heat pumps, constitutes a key component of state and city climate action plans.

The economics of heat pumps relative to natural gas heating will be an important driver of customer adoption of these technologies, and thereby determine the extent to which ambitious building electrification goals can be met in a timely manner. While heat pumps are much more efficient in converting energy into heating output than efficient natural gas boilers and furnaces, they also have higher initial capital costs.[1] Heat pumps' operating costs can also be higher than natural gas equipment depending on climate, equipment type and efficiency, electricity rates, and rate structures. Even in regions where heat pump operating costs are lower than operating costs for natural gas equipment, the operating cost gap will need to be significant to offset the upfront cost premium and return a reasonable payback for customers who are in the market to purchase a new heating system.

According to a recent United Nations report, the building sector was responsible for 38 percent of CO_2 emissions globally in 2019. Given the magnitude of building sector emissions, the decarbonization of this sector, mainly through heating electrification using heat pumps, constitutes a key component of state and city climate action plans.

Technology costs are expected to come down over time, and heat pumps will likely reach cost-parity with natural gas equipment eventually. However, if the operating costs for heat pumps turn out to be favorable compared to the operating costs for natural gas equipment, it is possible to see a significant uptake of the heat pumps even before the technology cost declines. In this white paper, we examine the role of alternative "cost-based" and "cost-reflective" rate designs in improving the economics of heat pumps by reducing their operating costs. We define cost-based rates as rates that recover a utility's entire cost of providing service to a class of customers, and define cost-reflective rates as rates that send efficient price signals reflective of the extent to which a change in a customer's timing or magnitude of usage would change overall utility costs. Default utility rates for the residential class typically consist of a small fixed monthly charge and a volumetric charge on kWh consumption. This type of rate is typically cost-based because it recovers the utility's revenue requirement for the class, but not very cost-reflective because transmission and distribution costs are not driven by kWh consumption.

1 A heat pump can deliver around 300 percent more energy in the form of heat than it consumes over the course of the heating season. An efficient gas boiler or furnace can convert about 95 percent of input energy into heating output.

This analysis considers alternative rates that are cost-based in the sense that they would collect the same amount of revenue from the average customer (who has not yet electrified) as the default rate. Therefore, the rates need not be limited to electric heating customers but could be designed for the residential class and made available to all residential customers (not just the electric heating customers) on a voluntary basis. In addition, all three alternative rates put forth in this analysis incorporate more cost-reflective components than the default rate. This includes components such as higher fixed charges, time-varying volumetric charges, and time-varying demand charges, all of which are more reflective of utility cost causation than flat volumetric charges. In other words, we are not advancing differing, subsidized rates for different end uses here. Rather, we are assessing the broader appeal of these structures, finding that there are alternative cost-based rates that could be made available to all customers, with customers with different appliances and use cases opting into these rates if the structure of the rates is better aligned with their usage profiles.

This white paper is structured in four sections. The second section describes our analytical approach to modeling customers' gas and electric usage for heating. The third section describes our modeling results from calculating heat pump and natural gas boiler heating bills under various rate structures. The fourth section concludes with the key takeaways from the white paper.

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Analytical Approach

The following general operating characteristics of heat pumps show the potential use of alternative cost-based rate designs that can help improve the economics of heat pumps:

- Heat pumps lead to higher electricity consumption (compared to using other fuels for heating) for a given household; therefore, lower volumetric rates would favor heat pump usage, all else equal.
- Most of the heat pump load materializes in the non-summer months; therefore, seasonally differentiated rates in summer-peaking systems (with lower non-summer rates) might favor heat pump usage, all else equal.
- A significant portion of the heat pump load tends to fall into off-peak periods (periods of relatively low system-wide electricity usage), which implies that various cost-based time-of-use (TOU) rates might favor heat pump usage, all else equal.
- Heat pumps tend to have high load factors,[2] which implies that demand-based rates might favor heat pump usage, all else equal.

Given these characteristics of heat pumps, we modeled heating requirements of a sample of single-family residential customers and computed their heating bills under heat pump and natural gas heating scenarios using alternative rate designs. This approach allows us to answer two key questions:

1. **What is the operating cost gap between gas heat and electric heat when using default rate structures?**

We modeled heating requirements of a sample of single-family residential customers and computed their heating bills under heat pump and natural gas heating scenarios using alternative rate designs.

2. **Do heat pump operating costs decline enough when using alternative cost-based electricity rate structures to mitigate the cost gap?**

We studied these operating cost gap metrics using a proprietary dataset of natural gas and electricity usage for 80 single-family residential customers of a large investor-owned utility with relatively high electricity rates and cold winters. Our analysis consisted of four steps:

Step 1: Estimate heating requirements for each customer by applying a regression model to their monthly gas usage. The regression model uses heating degree days (HDDs) to estimate the fraction of each customer's total gas usage that is used for space heating.[3]

Step 2: Model a hypothetical stand-alone cold-climate heat pump installed to replace each customer's natural gas heating system. The heat pump's hourly electric load profile was modeled using the customer's monthly heating requirement, historical hourly temperature data, and assumed heat pump technical specifications. This heat

2 Load factor refers to the ratio of the average hourly usage to the peak hourly usage for an appliance or for a customer. Higher load factors mean a usage profile is less "peaky."

3 Heating degrees are defined as the difference between an assumed set point (e.g., 65°F) and the outdoor temperature. Heating energy use is directly proportional to heating degrees.

pump load was then added to their actual electric load from the usage data to construct a "post-electrification" load profile.

Step 3: Calculate each customer's gas and electricity bills using both their actual "pre-electrification" usage and modeled "post-electrification" usage. We assumed all customers remain connected to the natural gas system to serve other end uses post-electrification (water heating, cooking, etc.). While gas bills were calculated using the default gas rate, electricity bills were calculated for four different rate structures including a flat default rate with a low fixed charge, a flat rate with a higher fixed charge, a seasonal volumetric TOU day/night rate, and a seasonal demand-based TOU rate. These are explained in detail in the sections below.

Step 4: Analyze the findings using two metrics to illustrate the cost gap between air source heat pumps (ASHPs) and natural gas heaters, and evaluate how these metrics change based on electricity rate structure:

1. **Operating cost gap:** comparison of gas heating bill vs. electric heating bill
2. **Payback period:** number of years needed to recoup the upfront cost premium of the heat pump based on annual operating cost savings

While we were able to uncover various insights with our approach, it has a few limitations. First, the analysis is based on one historical year of weather and usage data (2021); expanding this to several years would likely capture more weather variability and extreme events. Second, we modeled only two heating equipment types, cold-climate ASHPs and natural gas equipment, and we did not explicitly consider ASHP usage for space cooling. While we did not model the impact of ASHPs on cooling loads, cooling load is likely included in the original usage data for most customers due to the high penetration of air conditioning in this region.[4] ASHPs are typically more efficient at cooling than air conditioners and would have the effect of reducing customers' cooling loads.[5] We did not attempt to include this effect due to the difficulty of accurately disaggregating cooling loads from other electricity uses and due to the relatively small efficiency difference between air conditioners and heat pumps. Lastly, we did not model customer price response to alternative rate designs. Customers who opt into a different rate structure are likely to alter their usage to take advantage of their new rates. This will likely improve the economics of heat pumps further under these rate designs.

The following sections describe the assumptions and each stage of the analytical approach in further detail.

Step 1: Estimation of Customer Heating Requirement

Energy use for heating in buildings varies due to customer behavior, physical building characteristics, and outdoor temperature. In order to capture the diversity of heating requirements that will need to be served by heat pumps, we used each customer's historical monthly gas usage to estimate customer-specific heating energy use.

ASHRAE Guideline 14 Annex D outlines regression techniques that can be used to estimate a building's heating energy use using its whole-building energy use and one or more variables such as outdoor temperature and building occupancy.[6] Based on this guideline, we applied a three-parameter change-point linear model to estimate the customer's gas usage for heating based on their total usage, the outdoor temperature, and an assumed change-point temperature. The regression model was defined as:

4 According to the most recent results from the 2020 U.S. Energy Information Administration's Residential Energy Consumption Survey, 88 percent of U.S. households use air conditioning. Two-thirds of U.S. households use central air conditioning or a central heat pump as their main air conditioning equipment. See https://www.eia.gov/consumption/residential.

5 For customers who do not already have air conditioners, ASHP adoption and use for cooling will cause an increase in electric load. This should not be considered a negative effect, as the customer benefits from the availability of cooling. Indeed, as temperatures increase due to the impacts of climate change, cooling will become an increasingly necessary resource in most regions of the U.S. Under these circumstances, the adoption of ASHPs can be very beneficial, as they serve both heating and cooling needs and provide upfront cost savings by avoiding investment in two appliances.

6 ASHRAE Guideline 14–2014, Measurement of Energy, Demand, and Water Savings Annex D, Regression Techniques.

$$E = C + B_1 (B_2 - T)^+$$

Where:

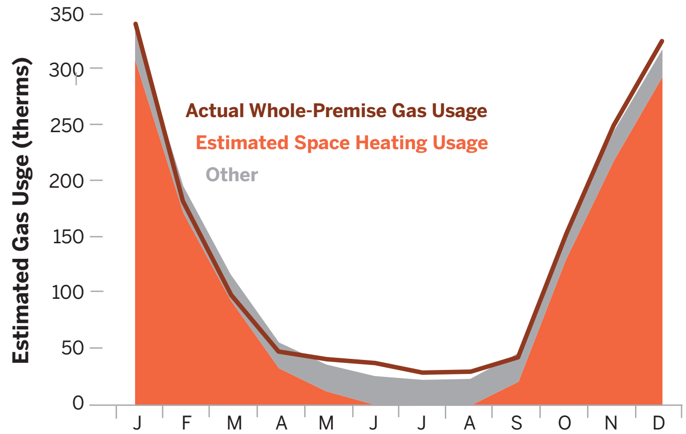
- E = Total gas usage
- C = Constant gas usage
- B_1 = Coefficient describing linear dependency of gas usage with outdoor temperature
- B_2 = Heating change-point temperature (assumed to be 65°F)
- T = Outdoor temperature
- + = Only positive values inside the parenthesis

This regression model yields a temperature coefficient of gas usage for each customer, which we used to calculate their monthly heating gas usage. Figure 1 illustrates a sample customer's actual monthly gas usage and the heating gas usage estimated by the regression model.

Figure 2 shows the distribution of estimated heating gas use across the 80 single-family residential customer sample. Most customers consume 1,000 to 2,000 therms of gas per year for space heating. Since only a portion of this gas usage is converted into useful heat by the natural gas heating equipment, we applied an efficiency factor of 80 percent to convert gas usage into heating energy requirements.[7] These heating energy requirements calculated for each individual customer formed the basis for heat pump electric load profiles modeled in this study.

FIGURE 1

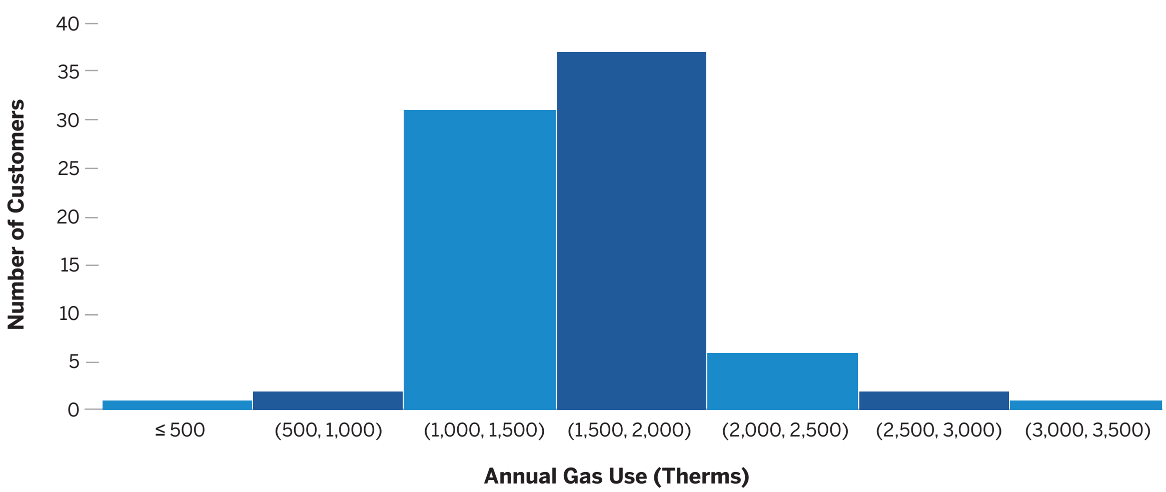
Actual Whole-Premise Gas Usage and Estimated Heating Gas Usage for a Sample Customer



Source: The Brattle Group.

FIGURE 2

Histogram of Estimated Heating Gas Use in the 80-customer Sample



Source: The Brattle Group.

7 "EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Reference Case" shows that the efficiency of the installed base of residential gas furnaces was 80 percent. See https://www.eia.gov/analysis/studies/buildings/equipcosts.

Step 2: Modeling of Heat Pump Electric Load

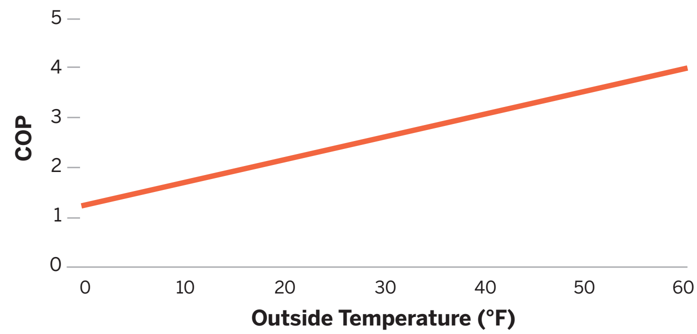
Heat pump loads are dependent on a range of factors including space heating needs, heat pump configuration, efficiency, and outdoor temperature. We utilized the customer-specific heating requirement estimates (as detailed above), historical hourly temperature data, and the assumed ASHP specifications to model hourly electricity demand.

First, we calculated hourly heating energy requirements by allocating the monthly heating energy requirement calculated in the previous section to each hour of the month based on the proportion of heating degrees that occurred in that hour. We then calculated the hourly electric load using the heat pump's coefficient of performance (COP)[8] in that hour given the outdoor temperature, as shown in Figure 3. This relationship is based on an assumed stand-alone cold-climate ASHP that meets the minimum requirements of the Northeast Energy Efficiency Partnership.[9]

We calculated hourly heating energy requirements by allocating the monthly heating energy requirement calculated in the previous section to each hour of the month based on the proportion of heating degrees that occurred in that hour.

FIGURE 3

Modeled Relationship Between Air Source Heat Pump COP and Temperature



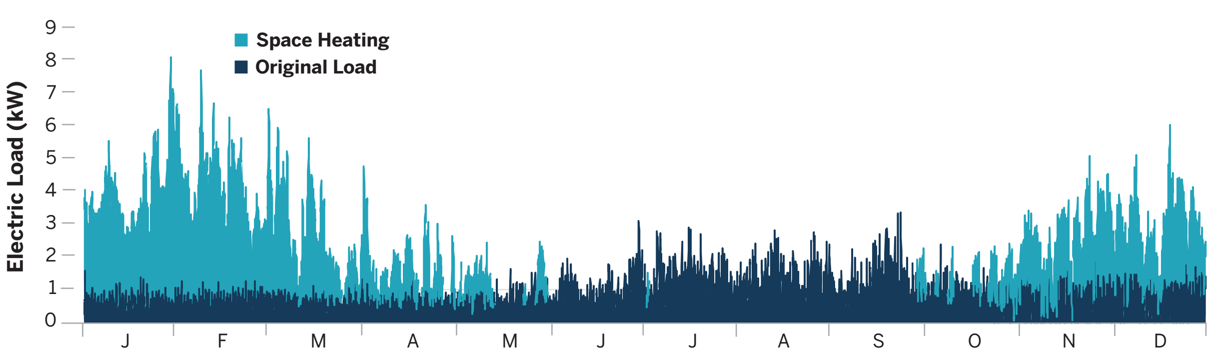
Air source heat pumps become less efficient as the outdoor temperatures fall.

Source: The Brattle Group.

Figure 4 illustrates that adding the modeled heat pump load to a customer's actual pre-electrification load significantly increases their total electric load. As shown in Table 1 (p. 7), both peak and annual usage more than

FIGURE 4

Modeled Hourly Post-Electrification Load for a Sample Customer



Source: The Brattle Group.

8 COP is a metric of heat pump efficiency, defined as the ratio of the thermal energy delivered to conditioned space to the electrical energy consumed by the heat pump.

9 The Northeast Energy Efficiency Partnership's Cold Climate Air Source Heat Pump Specifications Version 4.0 require that cold climate ASHPs have a COP of at least 1.75 at 5°F. We modeled a linear temperature relationship between a COP of 1.75 at 5°F and COP of 4 at 47°F with a 15 percent derating to account for the difference between rated and actual performance.

TABLE 1

Modeled Hourly Post-Electrification Load for a Sample Customer

	Non-Summer Peak Load	Summer Peak Load	Annual Total Load	Load Factor
Pre-electrification	2.37 kW	3.33 kW	6,100 kWh	21%
Post-electrification	8.13 kW	3.33 kW	15,943 kWh	22%
Percentage change	243%	0%	161%	7%

Note: Summer is defined as June-September, while non-summer is defined as October-May.

Source: The Brattle Group.

double for the sample customer. Heat pump impacts on load across the 80-customer sample are discussed below.

Step 3: Customer Energy Bill Modeling: Pre- vs. Post-Electrification and Alternative Rate Designs

Modeled ASHP adoption and associated changes in energy usage affect both natural gas and electricity bills. We calculated both types of bills using actual pre-electrification usage data, modeled post-electrification usage, and default and alternative rate structures.

Natural Gas Bill and Rate Assumptions

In this analysis we modeled a default gas rate option and assumed that all customers are on this rate pre- and post-electrification. We assumed that customers stay connected to the gas system post-electrification and continue to use gas for end uses other than space heating, such as cooking, water heating, or cooling. Table 2 shows the default natural gas rate, which has a declining block structure and seasonal differentiation, for this modeled utility. Gas bills were calculated based on this rate pre- and post-electrification. The billing determinant used for the gas rate was the total usage in a month across all hours. The declining block structure leads to different rates being applied for different blocks of usage as detailed in Table 2.

TABLE 2

Default Natural Gas Rate

	Season	Gas Rate (Default)
Customer charge ($/month)	All year	$24
Commodity charges ($/therms)	Summer	$0.60
	Non-summer	$0.55
Delivery charges ($/therms)	Summer	Block 1: $1.34 Block 2: $0.99 Block 3: $0.79
	Non-summer	Block 1: $1.32 Block 2: $0.97 Block 3: $0.77

Note: For the gas rate, summer is defined as April-October, while non-summer is defined as November-March.

Source: The Brattle Group.

In this analysis we modeled a default gas rate option and assumed that all customers are on this rate pre- and post-electrification. We assumed that customers stay connected to the gas system post-electrification and continue to use gas for end uses other than space heating, such as cooking, water heating, or cooling.

TABLE 3

Four Alternative Electricity Rate Designs

	Season	Rate I	Rate II	Rate III	Rate IV
Customer charge ($/month)	All year	$18	$45	$23	$28
Supply charges ($/kWh)	Summer	$0.09	$0.09	Peak: $0.265 Off-peak: $0.035	Peak: $0.215 Off-peak: $0.065
	Non-summer	$0.09	$0.09	Peak: $0.115 Off-peak: $0.035	Peak: $0.165 Off-peak: $0.065
Delivery charges, volumetric ($/kWh)	Summer	$0.155	$0.125	Peak: $0.215 Off-peak: $0.055	$0.015
	Non-summer	$0.145	$0.105	Peak: $0.075 Off-peak: $0.055	$0.015
Delivery charges, demand ($/kW)	Summer	—	—	—	Peak: $20.00 Off-peak: $5.50
	Non-summer	—	—	—	Peak: $15.00 Off-peak: $5.50
Peak definition	All year	—	—	8 AM-midnight on all days including holidays	Noon-8 PM on weekdays except holidays

Note: For electricity rates, summer is defined as June-September, while non-summer is defined as October-May.

Source: The Brattle Group.

Electricity Bill and Rate Assumptions

Electricity bills were calculated based on four rate options (Table 3):

- **Rate I:** Default rate with a fixed charge and flat volumetric charge
- **Rate II:** Rate with a higher fixed charge and lower flat volumetric charge
- **Rate III:** Seasonal volumetric TOU day/night rate
- **Rate IV:** Seasonal demand-based TOU rate

Each of the four modeled rate options uses one or more of the following monthly billing determinants:

- **Monthly usage (kWh):** Total usage in a month across all hours
- **Peak period usage (kWh):** Monthly usage within the day time window, defined as 8 AM to midnight all days including holidays for Rate III and noon to 8 PM on weekdays except holidays for Rate IV
- **Off-peak period usage(kWh):** Monthly usage in hours outside the peak window
- **Peak billable demand (kW):** Average of the four highest daily demand values in a month within peak window hours
- **Off-peak billable demand (kW):** Average of the four highest daily demand values in a month within off-peak window hours

Rate I is a default rate that is commonly offered to residential customers across many utilities. Rates II through IV were chosen to represent the various alternatives that are being considered in the industry as potential cost-based rate structures that can support heating electrification, without subsidizing these end-use technologies. Under Rate II, a higher fixed charge recovers a larger portion of the fixed costs of the delivery system independent of a customer's energy usage, thereby lowering the volumetric charge. Lower volumetric rates may encourage heat pump adoption since increasing electricity usage will not increase the bills as steeply

Demand charges have been rarely offered to residential customers in the U.S. due to their presumed complexity; however, they are being considered as an alternative voluntary rate design option that may help avoid large increases in bills due to increased usage.

as the default rate would. Rate III introduces a time-varying rate option in the form of a day vs. night TOU rate structure, where the lower costs of generating and delivering electricity during nighttime hours are reflected in the prices.[10] Rate IV also employs a time-varying structure but with demand charges instead of volumetric charges. Demand charges are generally used to recover costs associated with sizing infrastructure to serve peak demand. Demand charges have been rarely offered to residential customers in the U.S. due to their presumed complexity; however, they are being considered as an alternative voluntary rate design option that may help avoid large increases in bills due to increased usage. Moreover, heat pump usage tends to improve customer load factors, which is a favorable outcome under a demand charge–based rate design.

It is important to note that the alternative rates are designed to be revenue-neutral with the default rate pre-electrification. This implies that for the 80 customers in our sample, each of these rate designs would result in approximately the same total utility revenue based on their total pre-electrification load.[11]

Step 4: Heat Pump Cost Gap Metrics

Having developed the energy requirement associated with space heating, electricity requirement to meet this energy need, and alternative electricity rates that could be made available to heat pump customers, we then developed metrics to illustrate the operating cost gap between ASHPs and natural gas equipment under alternative rate designs.

Operating Cost Gap: Definition and Assumptions

We defined the operating cost gap as the difference between the heating portion of the electricity bill post-electrification and the heating portion of the natural gas bill pre-electrification. For an existing gas heating customer to consider replacing her heating system with a heat pump, she may at a minimum want to pay less for electric heating than gas heating—in other words, to achieve a negative operating cost gap. If this initial condition is not met, then to replace a natural gas heating system with a heat pump does not make economic sense. Once this condition is met, that is, if the operating cost gap is negative, then the prospective heat pump buyer could look for a reasonable payback period, which is typically in the range of five to 10 years for residential customers.

Figure 5 (p. 10) illustrates the operating cost gap in relation to natural gas and electricity bills pre- and post-electrification. The total energy bill is the sum of the gas bill (orange) and electricity bill (blue). The pre-electrification total energy bill includes the electricity bill for end uses other than heating, the gas bill for heating, and the gas bill for end uses other than heating. Post-electrification, the gas bill for heating reduces to zero due to electrification, and the electricity cost for heating is added to the electricity bill. Note that post-electrification, electricity and gas bills for end uses other than heating may also change if the customer switches to different rate schedules or changes their energy usage. *In this study, we focused on the change in the heating portion of the bills rather than the total bill in order to isolate the effect of electrification of heating.*

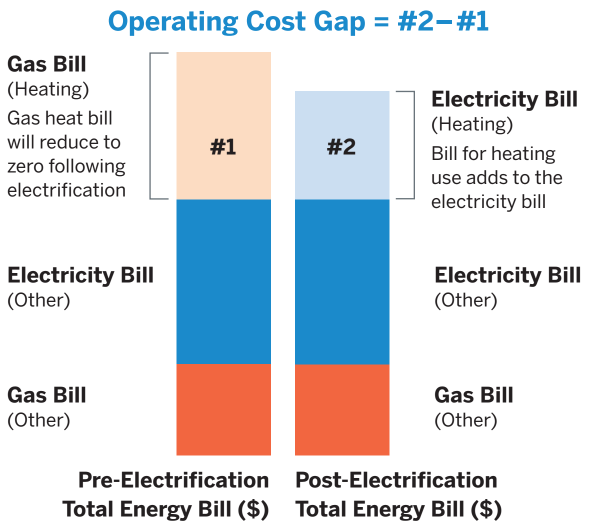
10 Although a TOU rate may encourage customers to shift usage to lower-priced hours in order to reduce bills, we do not capture this behavior in this analysis. We assume that customers continue with their consumption patterns.

11 Less than +/− 1 percent difference from the default rate.

Post-electrification, electricity and gas bills for end uses other than heating may also change if the customer switches to different rate schedules or changes their energy usage. In this study, we focused on the change in the heating portion of the bills rather than the total bill in order to isolate the effect of electrification of heating.

FIGURE 5

Illustration of a Negative Operating Cost Gap, $/month



The operating cost gap is the difference between #2 the heating portion of the electric bill (post-electrification) and #1 the heating portion of the gas bill (pre-electrification).

Source: The Brattle Group.

TABLE 4

Assumptions for Payback Analysis for Air Source Heat Pumps

Assumption	Low	Base	High
Gas furnace installation cost		$3,908	
ASHP installation cost*	$9,225	$13,605	$17,984
Federal ASHP rebate	$4,612	$6,802	$8,000

* ASHP installation costs assume a cold climate heat pump. AHSP costs were obtained from Nadel and Fadali (2022).

Notes: The table refers to all-in upfront cost including equipment and installation costs. The incentive value is calculated assuming a rebate of 50 percent of the cost of the ASHP up to a cap of $8,000, based on the provisions of the Inflation Reduction Act. ASHP = air source heat pump.

Source: The Brattle Group.

Payback Period: Definition and Assumptions

We defined the payback period as the number of years needed to recoup the upfront cost premium of the heat pump based on annual operating cost savings. We performed the payback analysis for the average customer using generic equipment cost assumptions; we do not attempt to estimate a customer-specific equipment cost. Instead, we show three cost cases (low, base, and high) to reflect the broad range of potential equipment costs across a diverse customer base. In addition, we conducted the payback analysis with and without the heat pump rebates of up to $8,000 provisioned by the Inflation Reduction Act (IRA).[12] We assumed that all components of both electric and natural gas rates grow at 2.4 percent per year. Cost assumptions used in the analysis are provided in Table 4.

12 Under the IRA, income-qualified customers can receive rebates of 100 percent of the equipment cost, and average-income customers can receive rebates of 50 percent of equipment cost, with a cap of $8,000 per customer. We modeled only the average-income customer's rebate incentive in our analysis.

Modeling Results

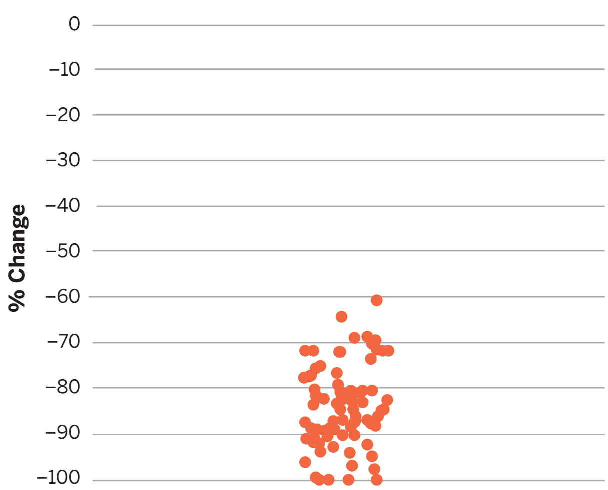
This section outlines the key results from our analysis of heating operating costs before and after electrification. First, we discuss modeled changes in customer usage and associated impacts on billing determinants. We then summarize the impact of these changes on the gas bill and compare the impact on the electricity bill under four different rate structures. Finally, we present the implications for heat pump economics using the operating cost gap and payback period metrics.

Energy Usage and Billing Determinants

Natural Gas

Given that space heating is the largest end use for natural gas customers, replacement of a gas furnace or boiler with an ASHP results in a major reduction in gas usage. As shown in Figure 6, for the 80-customer sample, our results show that switching to an ASHP would reduce annual gas usage by 60 to 100 percent, with an average reduction of 83 percent (Table 5). Any remaining gas usage is likely for cooking, water heating, or clothes drying, and customers are assumed to continue this usage after space heating electrification for the purposes of this study. The gas rate structure modeled in this study is relatively simple, with monthly usage being the only billing determinant.

FIGURE 6
Change in Natural Gas Usage Post-Electrification



Switching to an ASHP would reduce annual gas usage by 60 to 100 percent for the 80-customer sample.

Source: The Brattle Group.

TABLE 5
Average Gas Usage for the Sample, Pre- and Post-Electrification

	Average Annual Gas Usage in Sample
Pre-electrification	1,589 therms
Post-electrification	264 therms
Percentage change	−83%

Source: The Brattle Group.

Electricity

While the analysis of monthly total gas usage is sufficient to calculate natural gas bills, electricity bills require a more in-depth analysis of the temporality of usage in order to capture the impacts of alternative rates considered in this study. We added modeled ASHP load to each customer's pre-electrification actual usage and evaluated five different billing determinants to calculate bills under four different rate structures. The billing determinants are described in the section "Customer Energy Bill Modeling: Pre- vs. Post-Electrification and Alternative Rate Designs" above.

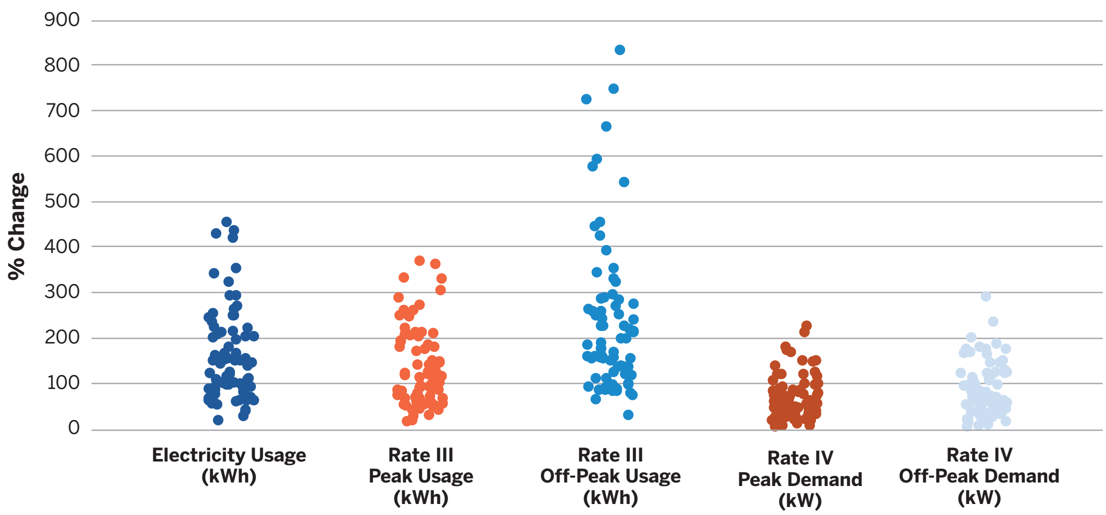
Figure 7 illustrates the impacts of electrification on each billing determinant for each customer. Table 6 summarizes the average annual billing determinants pre- and post-electrification across the 80-customer sample.

As seen in Table 6, the addition of ASHP load results in a significant increase in all five billing determinants. However, different billing determinants are affected to different extents due to patterns in the timing of ASHP load. Impacts on volumetric usage are greater than impacts on peak demand. In addition, ASHP load has greater impacts on off-peak billing determinants (both usage and demand) than on-peak billing determinants. This is because ASHP load is driven by outdoor temperature, and the coldest hours occur at night and early in the morning, outside the peak window.

In addition, all of the impacts are in the winter and shoulder season months, since we modeled heating electrification, as shown in Figure 8. This seasonality is significant as many summer-peaking utilities, including the one modeled in this study, currently have lower costs to serve in the non-summer months, with correspondingly lower cost-based rate levels in non-summer months.

FIGURE 7

Change in Annual Electricity Billing Determinants



Source: The Brattle Group.

TABLE 6

Average Monthly Billing Determinants Pre- and Post-Electrification

	Total Usage	Rate III Peak Usage	Rate III Off-Peak Usage	Rate IV Peak Period Demand	Rate IV Off-Peak Period Demand
Pre-electrification	740 kWh	544 kWh	196 kWh	3.2 kW	3.4 kW
Post-electrification	1,613 kWh	1,075 kWh	539 kWh	4.8 kW	5.5 kW
Percentage change	118%	98%	174%	53%	65%

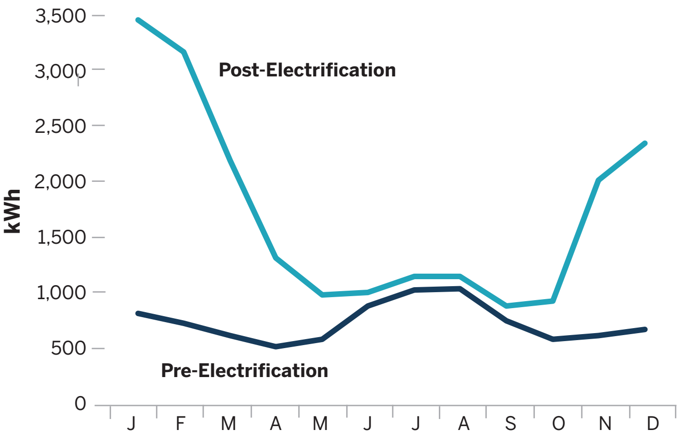
Electrification of heating with an ASHP would increase different electricity billing determinants to different extents. Peak window demand increases the least (53%), and off-peak window usage increases the most (174%).

Notes: Values shown in the table are monthly billing determinants averaged across all customers and months. Monthly billable demand for Rate IV is the average of the four highest daily demand values in a month within peak or off-peak window hours.

Source: The Brattle Group.

FIGURE 8

Average Monthly Electricity Usage in the 80-Customer Sample, Pre- and Post-Electrification



Source: The Brattle Group.

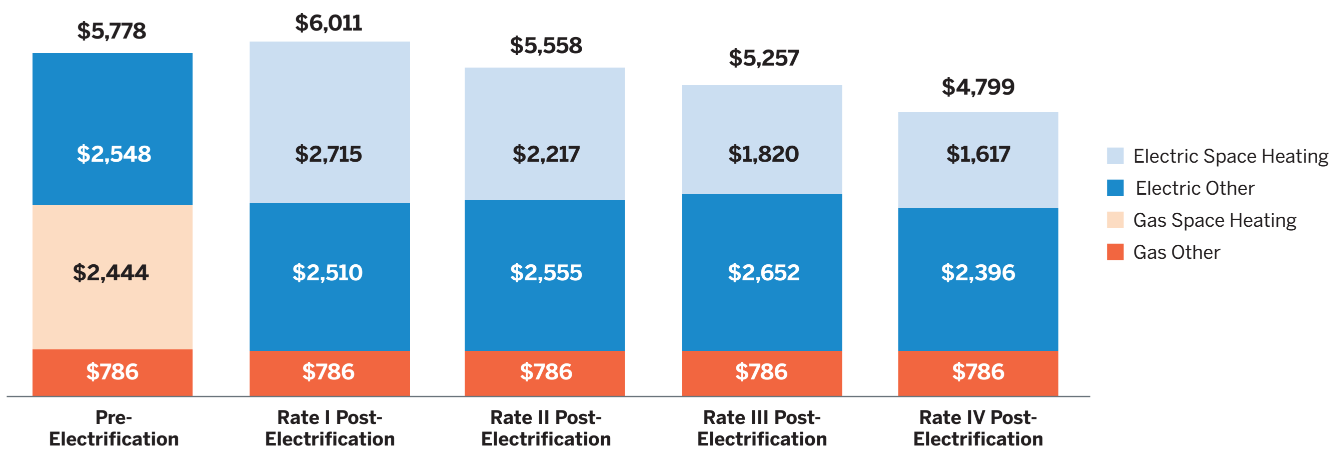
Both electrification and migration from the default rate to an alternative rate structure—even if it were to happen without electrification—affect customer bills. To provide a holistic view of the impact of these two changes, we analyzed annual total energy bills, defined as the sum of the natural gas and electricity bills. In addition, to isolate electrification-related costs we broke up the bills into a space heating component and a non-space heating, "other" component.

Figure 9 shows that the average annual total energy bill in the 80-customer sample was $5,778 before electrification. Replacing natural gas space heating with an ASHP while remaining on the default electricity rate would result in the average annual total energy bill increasing by about $233, leading to a total annual bill of $6,011. However, switching to any of the three alternative electricity rates changes this outcome. Under the three alternative rates, the post-electrification average annual total energy bill is $220 to $979 lower than the pre-electrification average annual total energy bill.

Recall that the three alternative rates are: Rate II with a higher fixed charge and lower volumetric charges, Rate III with time-varying volumetric charges, and Rate IV with time-varying demand charges. By switching from the default rate to one of these three alternative rates post-electrification of heating, the average customer with an ASHP could realize electricity bill savings of $453 to

FIGURE 9

Average Annual Energy Costs Before and After Electrification



Total energy bills are higher after electrification if a customer remains on electricity Rate I, the default rate. However, switching to one of the modeled alternative rates makes the post-electrification bill cheaper than the pre-electrification bill. The alternative rates are Rate II with a higher fixed charge and lower volumetric charges; Rate III with time-varying volumetric charges; and Rate IV with time-varying demand charges.

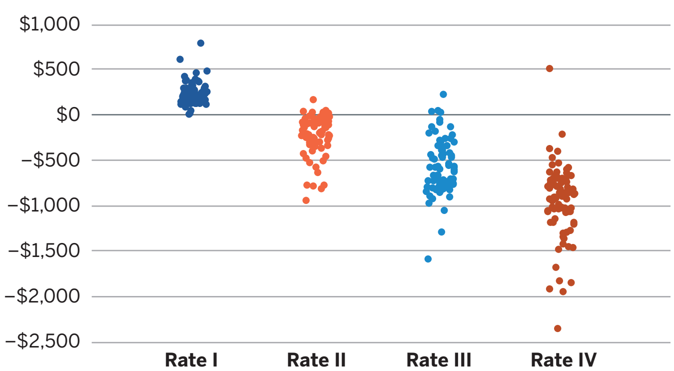
Source: The Brattle Group.

$1,212 annually. A significant portion of this reduction is from the cost of the ASHP's electricity usage, which is reduced from $2,677 on the default rate to $1,600 to $2,217 on the alternative rates. These ASHP operating costs should be compared to the average natural gas heating cost of $2,444 when a customer is deciding whether to electrify.

Rate migration also affects the non-heating portion of the electricity bill ("electric other"). This impact varies from customer to customer, with minimal average impact.

Post-electrification, switching from Rate I to one of the alternative rates largely results in customers saving. Out of 80 customers, 71 have lower bills on Rate II, 75 on Rate III, and 79 on Rate IV. However, there are some important differences between these three rates (as illustrated by Figure 10). The scale of bill reduction differs—Rate IV results in the lowest bills overall, followed by Rate III and then Rate II.[13] In addition, not all customers experience similar outcomes. The scale of bill reduction is much more variable for Rate IV than for Rate II,[14] i.e., it is easier to predict the change in a customer's bill when switching to Rate II. This is likely because it is possible for some customers' non-heating usage profile ("Electric Other") to be ill-suited to one or more components of the alternative rate structures. For example, if a customer's non-heating electricity usage is especially "peaky" (i.e., they have a low load factor), they may see bill increases from switching to a demand-based rate. A customer's usage might be peaky due to infrequently used but energy-intensive appliances such as pool pumps or a sauna. This type of impact is independent of heating electrification—this customer would have experienced a bill increase from migration to Rate IV regardless of whether they electrified. We outline some policy implications of these differences in the section "Key Takeaways" below.

FIGURE 10
Distribution of Total Energy Bill Changes Post-Electrification



Total energy bills are higher for most customers post-electrification if they remain on the default rate (Rate I). However, post-electrification bills are lower if they switch to one of the alternative rates (Rates II-IV).

Source: The Brattle Group.

Finally, we evaluated two heat pump cost metrics that a customer could consider when deciding between the purchase of a heat pump or a natural gas furnace: the operating cost gap and the payback period. As detailed in the section "Heat Pump Cost Gap Metrics," the heating operating cost gap is the difference between the heating portion of the gas bill and the heating portion of the electricity bill. This metric is calculated using the electric heating bill on each electricity rate schedule, thereby isolating heating bills from any costs that may be the effect of rate migration.[15] The heating operating cost gap is then used in conjunction with upfront cost assumptions to calculate the second metric, the payback period. These metrics can be used to assess the efficacy of different cost-based electricity rate designs in bridging the cost gap between ASHPs and gas furnaces.

Operating Cost Gap

Figure 11 (p. 15) shows that under the default electricity rate (Rate I), the operating cost gap is positive for all 80 customers and ranges from $12 to $790 per year. A positive operating cost gap means the electric heating bill is higher than the gas heating bill. Increasing the fixed charge and lowering the volumetric charge (Rate

13 Median savings is $927 for Rate IV and $583 for Rate III.

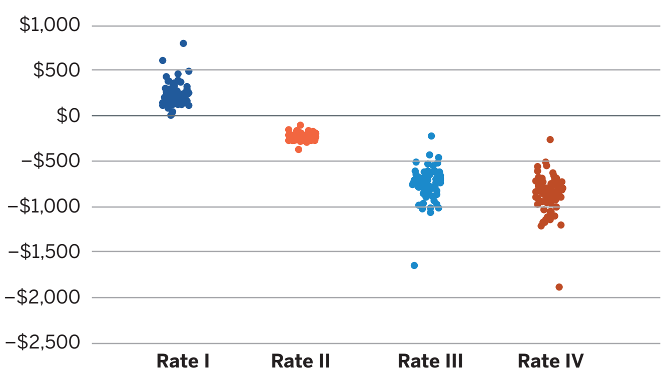
14 As measured by the standard deviation of the annual bill differences between the alternative rate and the default rate for the 80 customers.

15 For example, a customer that has a very flat electricity usage profile pre-electrification is likely to see bill reductions from switching to a demand-based rate. Non-heating-related impacts such as this are excluded from our definition of the heating operating cost gap.

Rate design is a powerful tool in addressing the operating cost gap between heat pumps and natural gas equipment. A change in electricity rate structure was shown to flip all 80 customers from a positive cost gap to a negative cost gap.

II) reduces the electric heating bill to a sufficient extent that the operating cost gap turns negative for all customers—they are saving money relative to heating with natural gas. Further, switching to a TOU day/night structure (Rate III) or a demand-based structure (Rate IV) results in even larger negative operating cost gaps. Rate IV is the most effective rate for reducing electric heating bills for our sample of 80 single-family residential customers.

FIGURE 11
Heating Operating Cost Gap



Source: The Brattle Group.

In summary, Figure 11 shows that rate design is a powerful tool in addressing the operating cost gap between heat pumps and natural gas equipment. A change in electricity rate structure is shown to flip all 80 customers from a positive cost gap to a negative cost gap. The scale of the impact is significant—the average operating cost gap can be reduced from $233 on Rate I to -$844 on Rate IV.

Most importantly, these impacts are possible to achieve with alternative rates that are cost-based and revenue-neutral to the default rate.

Payback Period

We used the average operating cost gap on each rate to calculate the number of years needed to recoup the upfront cost premium of an ASHP relative to natural gas heating. Table 7 shows that there is a significant degree of variance in payback periods based on the ASHP cost, the addition of the IRA incentive, and selection of the electricity rate schedule. Under the default Rate I, there is no scope for payback because heat pump operating costs are greater than gas heating operating costs; both upfront and ongoing costs are higher for heat pumps. However, the alternative rates greatly reduce payback periods across cases. For example, under the base cost assumptions with the IRA incentive, a heat pump can be paid back within its lifespan (~15 years) under any of the three alternative rate schedules. Rates III and IV are particularly beneficial, as the upfront cost of ASHPs can be fully recouped even in the high ASHP installation cost scenario. The IRA incentive cuts payback periods further.

TABLE 7
ASHP Payback Periods, by Electricity Rate Schedule, Without IRA Incentive | With IRA Incentive

ASHP Cost Case	Rate I	Rate II	Rate III	Rate IV
Base	NA | NA	>15 | 11 years	15 | 5 years	9 | 2 years
Low	NA | NA	>15 | 3 years	9 | 1 year(s)	5 | 1 year(s)
High	NA | NA	>15 | >15 years	>15 | 10 years	12 | 5 years

Table shows simple payback based on equipment costs and projected annual differences in total energy bills relative to the case with a gas heater. "N/A" means there are no operating cost savings, so payback is not possible.

Source: The Brattle Group.

Key Takeaways

This analysis shows that there are alternative cost-based rate designs that can improve the economics of heat pumps by resulting in electric heating bills being lower than natural gas heating bills (i.e., a negative operating cost gap). Specifically, we show that while the operating cost gap is positive for all 80 customers under the default electricity rate (Rate I) (energy costs for operating the heating equipment are higher post-electrification), moving to one of the three alternative rates flips all 80 customers from a positive cost gap to a negative cost gap, in which energy costs for operating the heating equipment are lower post-electrification.

All of the alternative rates modeled in this study are cost-based and revenue-neutral in that they recover the same costs as the default rate. They also improve upon the cost-reflectivity of the default rate by better aligning one or more components of the rate design with the underlying cost structure.

Increasing the fixed charge and lowering the volumetric charge (Rate II) reduces the electric heating bill to a sufficient extent that the operating cost gap turns negative for all customers. Further, switching to a TOU day/night structure (Rate III) or a demand-based structure (Rate IV) results in even larger negative operating cost gaps. Rate IV is the most effective rate for reducing electric heating bills, for our sample of 80 single-family residential customers, with Rate III closely following it.

More Cost-Reflective Rate Designs Improve the Economics of Electrification

These results reflect the fact that all of the alternative rate designs are better aligned with the marginal cost of generating and delivering power, compared to the default residential rate design, which typically is not. In many jurisdictions across the country, retail electricity prices are largely disconnected from the marginal costs. As Borenstein and Bushnell (2022) argued, "residential electricity rates exceed average social marginal cost in most of the U.S." and "there is large variation both geographically and temporally." To the extent that retail prices are above the short-run marginal costs because a large portion of the fixed costs of delivering power are also collected through volumetric rates, this creates a distortion in price signals and leads to suboptimal levels of electricity consumption and adoption of new customer-sited technologies. One of the unintended consequences of this phenomenon is the slower adoption of heat pumps, because heat pump usage increases total electricity consumption and therefore electricity bills, turning out to be uneconomic under typically volumetric default residential electricity rate structures.

All of the alternative rates modeled in this study are cost-based and revenue-neutral in that they recover the same costs as the default rate. They also improve upon the cost-reflectivity of the default rate by better aligning one or more components of the rate design with the underlying cost structure. These alternative rates also favor the operating characteristics of heat pumps:

- **Rate II** has a higher fixed charge and lower volumetric charge, which is favorable for heat pumps since this equipment substantially increases a household's electricity usage.

- **Rate III** is a seasonal day/night TOU rate, with lower rates for off-peak (night) hours and also lower day and night rates for the non-summer season. A significant portion of the heat pump load tends to fall into the off-peak periods because those tend to be the coldest, which implies that various cost-based TOU rates might favor heat pump usage, all else equal. Moreover, most of the heat pump load materializes in the non-summer months; therefore, seasonally differentiated rates in summer-peaking systems (with lower non-summer rates) might favor heat pump usage, all else equal.
- **Rate IV** is a seasonal TOU-based demand rate. Heat pumps tend to have high load factors, which implies that demand-based rates might favor heat pump usage, all else equal. In our rate design, we defined the billing demand to be the average of the top four demand hours, with the averaging intended to avoid the unpleasant customer experience of getting a high bill due to one high hour.

It is important to note that as the system conditions evolve, and summer-peaking systems become winter peaking with increasing levels of building electrification, rate structures may need to be refreshed to maintain their cost-reflectivity. Some of the attractive features of the rates modeled in this study (i.e., lower non-summer rates due to seasonality) may need to be eliminated at that time since the system cost drivers would no longer support these design choices. These revisions and adjustments are all part of the rate design process, since it is not possible to "future-proof" rate designs.

These Alternative Rate Structures Have Implications for Customers' Other Electric Loads

While our analysis showed that these alternative rates were effective in creating a negative operating cost gap for heating (a lower cost of heating after electrification), it is important to understand the implications of these rates for customers' other electric loads. Rate migration can create costs or savings independent of heating electrification, depending on the nature of customers' non-heating loads. This is an important consideration when marketing alternative rates to customers. For some of the customers in the sample, even before any electrification, switching to the TOU rate (Rate III) would increase their electricity bill by ~$200/year. (This increase could be reduced or eliminated through load response to TOU rates, although we did not model this impact in our study.) On the other hand, there are some customers for whom switching to one of the demand-based rates would reduce the bill by ~$100/year even before any electrification. Utilities may choose to develop screening tools to determine which customers may benefit from these alternative rates and market these rates accordingly to the customer base.

For the purposes of this study, we assumed that customers maintain their gas service for non-heating-related use cases such as cooking. This implies that these customers continue to pay the fixed customer charges for the gas service, along with the cost of volumetric gas usage. Fully electrifying a household would create additional savings by allowing it to avoid all gas charges (an additional $350/year in fixed gas charges for a single-family home). It is very likely that gas rates will increase faster than electricity rates in the next decade; therefore, the cost advantage of heat pumps will only increase over time.

It is important to note that as the system conditions evolve, and summer-peaking systems become winter peaking with increasing levels of building electrification, rate structures may need to be refreshed to maintain their cost-reflectivity.

Information Barriers Need to Be Addressed

Lastly, the availability of alternative rates that favor the economics of heat pumps does not necessarily mean that customers will start taking advantage of these rates in droves. Information barriers need to be addressed through utility programs targeting customers and pairing them with the rate design most favorable to them. Utilities can develop data analytics tools to identify customers who may be getting close to replacing their heating systems and "catch" them before they make their investment decision. Contractor training programs could be developed in which contractors increase awareness for new rates for customers who are in the market for a new heating system. With the availability of alternative rates, contractors could take into account the rate characteristics to make system recommendations. For example, if the demand charges are very high in an alternative rate, it could mean that purchasing a highly efficient cold-climate heat pump is a better choice than a less efficient heat pump with resistance backup even if there is an upfront cost premium for the cold climate heat pump.

The Use of Cost-Reflective Rate Designs Is Increasing

More and more utilities are starting to move toward more cost-reflective rate designs. Some are increasing their fixed customer charges to move them closer to the values implied by their cost-of-service studies. Others are moving toward time-varying rates, mostly in the form of voluntary/opt-in rates, but in a few cases offered as default, opt-out rates. When utilities offer opt-in cost-reflective rates, customers are able to opt in to the rates that are most convenient for their "energy lifestyle." To the extent that all of these alternative voluntary rates are cost-reflective, it will be possible to achieve a win-win: customer satisfaction will increase and utility cost recovery will become more equitable.

When utilities offer opt-in cost-reflective rates, customers are able to opt in to the rates that are most convenient for their "energy lifestyle." To the extent that all of these alternative voluntary rates are cost-reflective, it will be possible to achieve a win-win: customer satisfaction will increase and utility cost recovery will become more equitable.

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Heat Pump–Friendly Cost-Based Rate Designs

By Sanem Sergici, Akhilesh Ramakrishnan, Goksin Kavlak, Adam Bigelow, and Megan Diehl

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