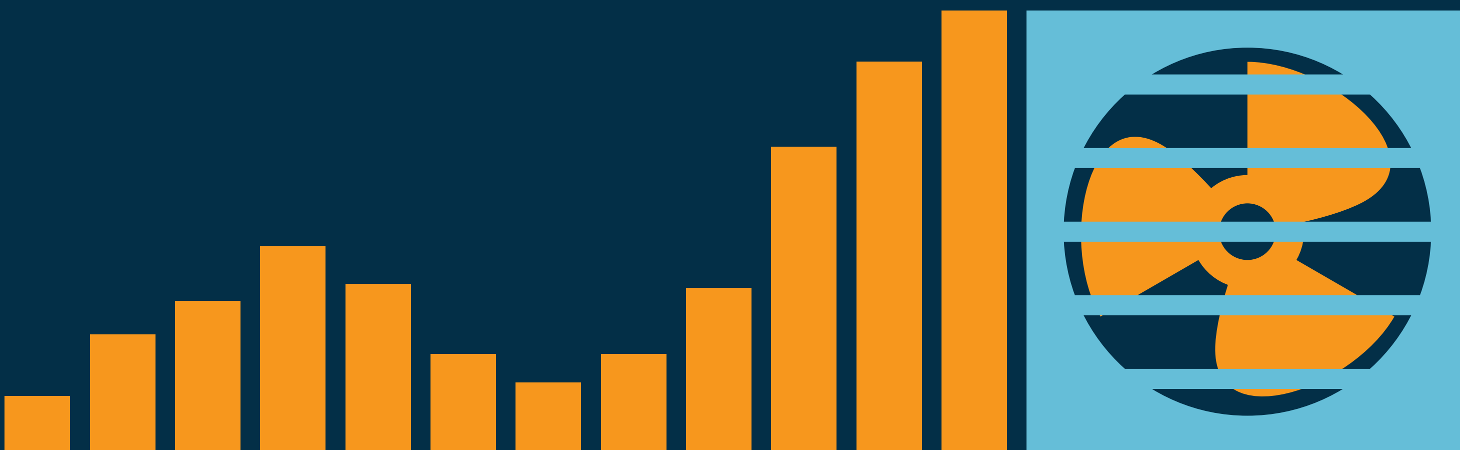
Heat Pump Rates in New York State



An analysis of cost-based and cost-reflective rates for heat pump customers

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April 2026

About this report

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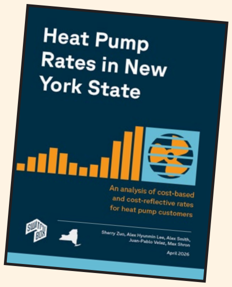

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Introduction

New York faces two intertwined energy challenges: rising electricity bills that strain household budgets across the state and the imperative to reduce reliance on fossil fuels, which are driving both climate change and a global energy crisis. The Climate Leadership and Community Protection Act (CLCPA) mandates an 85% reduction in greenhouse gas emissions by 2050[1] and the state's Scoping Plan identifies building electrification — replacing gas furnaces and boilers with electric heat pumps — as one of the greatest opportunities to achieve those reductions.[2] Just as the challenges of energy affordability and fossil fuel reduction are connected, so are the solutions. As this report shows, modernizing **rate design** can advance affordability and reduce fossil fuel use and emissions.[3]

Under today's electric rates — the regulated prices for electric infrastructure set by the state — switching from a gas furnace to an air-source heat pump often *increases* a household's total energy bills — despite heat pumps being two to three times more efficient.[4] Affordability concerns tied to higher **operating costs** are a significant barrier to heat pump adoption, discouraging homeowners from making the switch even when rebates and tax credits reduce the upfront cost of the equipment and installation.[5]

High energy bills are not an inherent feature of heat pumps. Instead, they largely result from how utilities recover the costs to build, maintain, and operate the infrastructure that delivers electricity to homes. Utilities charge residential customers for these **delivery costs** using **volumetric rates** — to pay for the transmission and distribution network, households pay a fixed number of cents for every kWh of electricity they consume. This pricing policy assumes that total electricity *usage* drives infrastructure costs: that the more a household consumes, the more delivery costs they cause, and the more they should pay.[6]

This assumption is false. Currently, electricity usage only drives infrastructure costs when the grid is congested — typically, on the hottest summer afternoons. When a home installs a heat pump, although it starts using significantly more electricity, the vast majority of this usage occurs during the winter, when the grid has ample spare capacity. Nevertheless, utilities charge

1 See §75-0107 of the CLCPA (NYS 2019).

2 See p.176 of the *Scoping Plan* (NYS Climate Action Council 2022).

3 3 See Northeast Energy Efficiency Partnerships, *Modern Rate Design in the Northeast* (NEEP 2025), which argues that modernizing electric rates across the Northeast is necessary to simultaneously control costs, support electrification, and advance equity.

4 See pp. 14-15 of The Brattle Group's *Heat Pump–Friendly Cost-Based Rate Designs*, a white paper prepared for the ESIG (Sergici et al. 2023).

5 For the operating-cost penalty as a barrier to heat pump adoption, see this blog post from RMI (Dammel et al. 2024).

6 Flat volumetric pricing, like all rate design, is a policy choice, not a technical necessity. Regulators can modify it.

Delivery costs

The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.

Volumetric rates

A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

heat pump customers for each of these additional kWhs as if they were all causing new infrastructure costs.

The result: utilities systematically overcharge heat pump customers for delivery, penalizing the very customers New York most needs to encourage. Meanwhile, their overpayments effectively lower the electricity bills of customers who heat with delivered fuels and natural gas, the fossil fuels the state is trying to phase out.

This dynamic is not new. In 2019, the New York State Energy Research and Development Authority (NYSERDA) published the first study to examine how New York's utilities are overcharging the state's heat pump customers.[7] NYSERDA estimated that under **default rates**, fuel oil customers switching to air-source heat pumps would overpay by an average of $534 to $1,826 per year, depending on their utility and building type. But no study has rigorously measured the cross-subsidy for all customers across the state, proposed concrete rate designs to eliminate it, or evaluated what those rates would mean for household bills and energy equity. Existing optional rates — such as the **time-of-use tariffs** available in some service territories — were not designed to address this structural problem.

This report measures the heat pump overpayment for all customers across the state, identifies concrete rate designs to eliminate it, and evaluates what those rates would mean for household energy bills and burdens.

Using data and software from the National Renewable Energy Laboratory (NREL),[8] we measure the delivery cross-subsidy for every major electric utility in New York and find that utilities are overcharging heat pump customers by an average of **$855** per year — approximately **$170 million** statewide.

We then model three distinct heat pump rate designs, based on the true **cost to serve** heat pump customers in each utility territory, and show that these rates would transform the economics of heat pumps in New York. Under the modeled rates, **72%** of gas-heated households would save by switching to air-source heat pumps, up from just **27%** under **default rates**.

7 For NYSERDA's analysis of the "inverse cost shift," see pp. 58-61 of the agency's *Analysis of Residential Heat Pump Potential and Economics* report (NYSERDA 2019).

Default rates

The electric supply and delivery rates a utility's customers are automatically enrolled in.

Time-of-use (TOU) rates

A volumetric rate whose per-kWh price varies by time of day, typically higher during an "on-peak" window when the grid is more likely to be strained and electricity is most expensive to produce, and lower during "off-peak" hours.

8 Specifically, NREL's ResStock building energy simulations (NREL 2024) and Customer Affordability, Incentives, and Rates Optimization (CAIRO) model (NREL 2026). We also used marginal cost data from NYISO and NYS utilities.

Cost of service

*The costs associated with generating and delivering electricity to a particular customer or customer class. A customer's **delivery** cost-of-service is their fair share of delivery costs; **supply** cost-of-service is their share of supply costs.*

Executive Summary

This report analyzes the gas and electric bills of heat pump customers in New York State and finds that:

- **Under today's default rates, most gas-heated homes would pay more after switching to heat pumps.** Only **27%** of natural gas-heated households would save on their annual energy bills after installing a heat pump — not because heat pumps are inherently expensive to run, but because utilities overcharge heat pump customers for the poles and wires that deliver electricity to them.
- **Electric utilities are overcharging heat pump customers for poles and wires by an average of $855 per year**, or $19,658 over the lifetime of the heat pumps.[9] Heat pump customers' electric delivery cost of service is only **2%** higher than that of gas-heated customers, but their electric delivery bills are **109%** higher.
- **New York's electric utilities are overcharging heat pump customers by a total of $170 million per year** — money that heat pump customers are effectively transferring to electric customers who heat with fossil fuels. We modeled three distinct rates that eliminate overpayments by heat pump customers (as well as electric resistance heating customers) and reduce the underpayment by fossil fuel heating customers.
- **First, we modeled what a dedicated heat pump delivery rate would look like for each utility.** By design, customers that adopted these rates would stop being overcharged.
- **This rate would transform the economics of operating heat pumps.** If they adopted the dedicated delivery rate, **72%** of gas-heated households would save by switching to heat pumps, up from **27%** under default rates.
- **The impact on non-heat-pump customers would be modest**: if every single existing heat pump customer adopted the modeled rates, the impact on other electric customers would amount to an average of **$2.00** per month. This would be a one-time increase; enrolling new

9 New York State's Technical Resource Manual (NYSJU 2025) assumes a 23 year effective useful life for cold-climate air-source heat pumps.

heat pump customers going forward would not have this impact once rates were fixed.

- **The modeled rate could also improve energy affordability for low-to-moderate income (LMI) households.** If LMI households that install heat pumps adopted the dedicated delivery rate and also enrolled in existing LMI discount programs, the share of highly energy burdened households would drop by **15** percentage points compared to today.[10]
- **Second, we modeled a more inclusive electric heating rate.** Including electric resistance customers in the dedicated delivery rate would also lower bills for these customers, which utilities are also overcharging at present: they would save an average of $883 a year. If every heat pump and electric resistance customer in New York State adopted this rate, the bill impact on electric customers that heat with fossil fuels would be higher than if the rate were only available to heat pump customers.
- **Third, we modeled a time-of-use heat pump rate.** Adding time-of-use (TOU) pricing can be a helpful complement to dedicated rates for heat pump (or electric heating) customers. TOU pricing adds modest additional savings for heat pump customers, though the majority of savings in the TOU heat pump rate, as in the dedicated delivery rate, come simply from charging heat pump customers lower delivery prices than default rates, which avoids overcharging them.

10 We define highly energy burdened households as those that spend more than 6% of their annual income on home energy bills.

Background

To follow along with this report, the reader needs to understand electric utility **costs**, **bills**, and **rates**. These concepts are introduced in this section, and fully explained in an in-depth primer in p. 61.

Costs

The expenses a power sector companies incur to generate, transmit, and distribute electricity, including capital costs and operating costs.

Bills

The total amount a customer pays each month in order to cover their share of supply and delivery costs.

Rates

The regulated prices used to calculate customer bills. Includes fixed and volumetric charges.

COSTS: SUPPLY AND DELIVERY

To generate and deliver electricity to customers, power sector companies, including utilities, incur two kinds of costs:[11]

1. **Supply costs**: the money spent to build and operate power plants — as well as batteries and renewables — and burn fuel to generate the electricity.
2. **Delivery costs**: the money spent to build and operate the transmission and distribution network that delivers that electricity to customers.

11 Electric utilities in NY used to own and operate generation, transmission, and distribution. Now they only do the latter, while power producers handle generation, and Transmission Owners (Transcos) handle transmission.

BILLS: SUPPLY AND DELIVERY

Utility customers ultimately pay for these **costs** (and company profits) through their utility **bills**. Utility bills have a supply section, which pays for **supply costs**, and a delivery section, which pays for **delivery costs**.

COST OF SERVICE: SUPPLY AND DELIVERY

A customer's bill tells you how they are *actually* paying for these costs, but their **cost of service** tells you how much they *should* be paying. A customer's cost of service is their "fair share" of the utility's costs: in a given time period, every customer has a supply cost of service and a delivery cost of service — the total supply and delivery costs they impose on the utility in that period.

In theory, a customer's bill should equal their cost of service: the delivery bill should equal the delivery cost of service, and the same for supply. In practice, it rarely does.

RATES: FIXED AND VOLUMETRIC

That's because supply and delivery bills don't magically reflect a customer's supply and delivery cost of service; instead, they are calculated using **rates**. Rates are simply the regulated *prices* charged by the utility, and they are an imperfect proxy for the costs they are intended to collect.

For residential customers, rates mostly come in two flavors:[12]

- **Fixed**: a set monthly charge for being connected to the grid (e.g., $16 per month), similar to a rent or lease payment
- **Volumetric**: a per kWh charge for every unit of electricity consumed (e.g., 10¢/kWh), similar to pumping gasoline at a gas station

12 Rate design enthusiasts will be quick to point out the omission of demand charges, where customers pay for the highest kW of demand they use in a month — power instead of energy. Demand charges are out of scope for this report.

HOW FIXED AND VOLUMETRIC RATES RELATE TO SUPPLY AND DELIVERY BILLS

Supply bills are calculated entirely using volumetric rates (¢/kWh) in New York State — the utility reads the customer's meter to see how much electricity they consumed that month, and then charges the customer a certain number of cents for each of those kWh.

Delivery bills, on the other hand, are calculated using both fixed and volumetric rates:

- Every customer pays a fixed monthly charge — about $16 to $24 per month across the seven large New York electric utilities in this analysis.
- Volumetric delivery charges add about 6 to 22 cents per kWh, depending on utility, season, and (for some tariffs) usage tier — and for most customers, these volumetric charges make up the bulk of the delivery bill. The implication: if you consume more electricity, you don't just pay more for that electricity — you also pay more for the poles and wires that deliver it, regardless of whether you trigger the need for grid upgrades.

THE FAIRNESS PROBLEM

And therein lies the problem: heat pumps use significantly more electricity than the fossil heating systems they replace. Their supply cost of service goes up — they are consuming more electricity, after all — and their supply bill rises to match it.[13]

But because delivery bills are also largely calculated using volumetric rates, the amount they pay for poles and wires goes up significantly as well, even though their delivery cost of service only increases slightly — and in some cases actually decreases.[14]

As a group, heat pump customers' delivery bills are larger than their delivery cost of service, and the difference creates a **cross-subsidy**: heat pump customers are quietly lowering the electricity bills of their fossil-heating neighbors. We call this the **fairness problem**, and it is the central focus of this report.

For more on the fairness problem, see p. 70.

COST-BASED RATES

In this report, we call a rate **cost-based** if it eliminates the cross-subsidy a group of customers is paying into — in other words, if the rate collects total delivery revenue from that group equal to the group's delivery cost of service. A rate that is **cost-based** for a group of customers solves the fairness problem for that group.

For example, if a utility has 10,000 heat pump customers and their total delivery cost of service is $10,000,000 a year, a delivery rate that is cost-based with respect to heat pump customers is one that would collect $10,000,000 from those customers (assuming they all adopted the rate). Put another way, since the average cost of service for heat pump customers in that utility territory is $1,000 per year, a cost-based rate is one that would charge *an average* of $1,000 per year to each heat pump customer that adopted it.

In this report, we design a cost-based delivery rate that would solve the fairness problem (p. 30) for heat pump

13 The opposite happens for **electric resistance** customers: heat pumps use significantly less electricity to produce the same heat, so supply cost of service goes down, and supply bill goes down to match it.

14 A residential customer's delivery cost of service only grows if they consume more electricity during the summer peak, which contributes to the need for new T&D capacity. Customers replacing central air conditioning with heat pumps will decrease their summer peak consumption, and therefore their delivery cost of service, because heat pumps cool more efficiently. Customers with partial or no cooling will increase their summer peak consumption, and therefore their delivery cost of service. However, these added costs are typically dwarfed by the larger delivery bills associated with winter heating — consumption that does not grow a customer's delivery cost of service.

Cross-subsidy

The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group.

Fairness problem

When the principle that a customer group's bills should match their overall cost of service is violated.

Electric resistance

A class of electric heating equipment — baseboard heaters, electric furnaces, space heaters — that converts electricity directly into heat by running a current through a resistive element.

customers. We also design a cost-based delivery rate for electric heating customers as a whole, meaning it would solve the fairness problem faced by both heat pump customers and **electric resistance** customers (p. 41). Currently, utilities are also overcharging electric resistance customers for delivery.

THE EFFICIENCY PROBLEM

The fairness problem is distinct from the **efficiency problem**, which is about whether price signals to customers when costs are high or low.

When rates are **flat**, customers have no reason to consume more electricity when it's cheap to produce or less when it's expensive — or to curb **peak-hour** consumption that drives new transmission and distribution (T&D) buildout. The result: underconsumption when electricity is cheap, overconsumption when it's expensive, and a bigger grid than we need — all of which makes supply and delivery rates more expensive for everyone.

For more on the efficiency problem, see p. 71.

Efficiency problem

When the principle that rates should reflect underlying costs — rising when supply or delivery costs are high and falling when they are low — is violated.

Flat volumetric rate

Volumetric rates that charge the same price per kWh at all hours and seasons. Most default residential electricity rates in the U.S. are flat.

COST-REFLECTIVE RATES

In this report, we define a **time-varying rate** as a volumetric rate whose ¢/kWh price changes over time. Examples include **seasonal rates**, **time-of-use (TOU)**, critical peak pricing (CPP), and real-time pricing (RTP) (see p. 72 for details).

We define a **cost-reflective rate** as a **time-varying rate** whose ¢/kWh prices track the underlying costs of generating and delivering electricity to a group of customers — costs which themselves change over time.[15]

15 By underlying cost, we mean **marginal energy costs** and **marginal T&D capacity costs**, also known as short-run and long-run marginal costs in the economics literature. For simplicity, we avoid using the term marginal cost here, but we discuss it in detail in p. 61.

Cost-reflective rates can reflect both **supply costs** and **delivery costs**:

- **Supply:** the cost of generating electricity varies hour by hour. In theory, a *fully* cost-reflective supply rate would have a volumetric price that changes hour by hour to reflect that underlying cost.
- **Delivery:** most of the year, electricity flows over a T&D network that's already built, so the marginal cost of delivering it is **zero**. That changes during the hottest hours of summer, when lines serving a particular customer may be nearing capacity and any additional consumption contributes to the need for a grid upgrade. A *fully* cost-reflective delivery rate would be zero most of the year, and priced at the cost of those capacity upgrades during **peak hours**.[16]

Real-world time-varying rates fall short of this ideal, but they are typically more cost-reflective than flat volumetric rates. The more cost-reflective a rate is — the more accurately its price reflects fluctuating supply and delivery costs — the more it promotes economic efficiency.

In this report, we design a relatively **cost-reflective** time-of-use supply and delivery rate that would solve the fairness problem while also addressing the efficiency problem (p. 46).

Peak hours

The hours in a year when a particular infrastructure component — be it a distribution line, transmission line, or the grid as a whole — experiences peak demand. If the component is at capacity, usage during these hours triggers the need for upgrades, which drives delivery costs up.

16 Such a rate would collect marginal T&D capacity costs — the cost of upgrading the network to handle growing peak loads. But it would not suffice to collect embedded T&D costs — the costs of the transmission and distribution network that is already in place — which make up the vast majority of delivery costs. In practice, utilities that offer time-of-use delivery rates usually inflate these prices above marginal T&D capacity costs to collect enough revenue to cover their embedded costs, but this hurts cost-reflectiveness and thus economic efficiency. For a full discussion, see p. 71.

Glossary

Bills: The total amount a customer pays each month in order to cover their share of supply and delivery costs.

Bill Alignment Test: Analytical framework that compares what each customer pays bills to their allocated cost of service. Used to measure cross-subsidies between customer groups

Capacity (infrastructure): The maximum electric current a piece of transmission or distribution equipment — a line, transformer, or substation — can carry safely without damaging the equipment. When demand approaches an asset's capacity, the utility must either upgrade it, or build new infrastructure to handle the load.

Capacity costs: The capital cost of an infrastructure project that increases the grid's capacity. Capacity costs are a kind of delivery cost, and they exist at every level of the grid: generation capacity costs (power plants), transmission capacity costs (high-voltage lines and bulk substations), and distribution capacity costs (feeders, transformers, secondary lines).

Costs: The expenses a power sector companies incur to generate, transmit, and distribute electricity, including capital costs and operating costs.

Cost allocation: The regulatory process of dividing a utility's total revenue requirement among the groups of customers it serves, in proportion to each group's cost of service. Typically applied to broad customer classes (residential, commercial, etc.); can also be performed for groups *within* a class (e.g. heat pump customers).

Cost-based rate: A rate that bills a group of customers in line with their cost of service. Cost-based rates solve the fairness problem: the average customer in the group, and the group as a whole, neither overpays nor underpays relative to what it costs to serve them.

Cost-causation principle: The idea that utility costs should be paid for by the customers that cause them: the cost to generate electricity should be paid by those who consume it, the cost to build infrastructure to meet peak demand should be borne by customers who use the network during peak hours.

Cost-reflective rate: A rate with prices that track underlying supply and delivery costs. Cost-reflective rates solve the efficiency problem by giving customers an incentive to shift consumption to hours with lower costs, but they don't guarantee that each group pays their fair share of these costs.

Cost of service: The costs associated with generating and delivering electricity to a particular customer or customer class. A customer's *delivery* cost-of-service is their fair share of delivery costs; *supply* cost-of-service is their share of supply costs.

Cross-subsidy: The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group.

Default rates: The electric supply and delivery rates a utility's customers are automatically enrolled in.

Delivery costs: The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.

Efficiency problem: When the principle that rates should reflect underlying costs — rising when supply or delivery costs are high and falling when they are low — is violated.

Economic burden: A customer's total marginal cost of service: the sum of their hourly consumption multiplied by hourly marginal energy and T&D capacity costs, during an entire year.

Electric resistance heating: A class of electric heating equipment — baseboard heaters, electric furnaces, space heaters — that converts electricity directly into heat by running a current through a resistive element.

Embedded costs: Costs that have already been incurred, and must be recovered from customers regardless of how much customer electricity they use, or when they use it. Mostly consists of the delivery costs associated with T&D infrastructure that has already been built.

Energy burden: The share of a household's annual income spent on home energy bills — electricity, natural gas, delivered fuels. A widely used indicator of energy affordability stress.

Fixed charges: A flat dollar amount per month that a customer pays regardless of how much electricity they use.

Flat volumetric rates: Volumetric rates that charge the same price per kWh at all hours and seasons. Most default residential electricity rates in the U.S. are flat.

Fairness problem: When the principle that a customer group's bills should match their overall cost of service is violated.

Load shifting: The practice of moving electricity consumption from one time of day to another without reducing total use, typically in pursuit of lower prices. Incentivized by TOU and other time-varying rates.

Marginal costs: The costs of generating or delivering the next unit of electricity. In other words, supply or delivery costs that are caused by customers choosing to consume an additional kWh at particular times.

Marginal energy costs: The operating cost of generating an additional kWh of electricity at a particular time. Marginal energy costs vary hour by hour with demand and the mix of generators running: they are low when abundant renewables are on the grid or demand is slack, and high when expensive peaker plants are running to meet peak load.

Marginal generation capacity costs: The capacity cost associated with triggering the construction of a new megawatt of generation capacity at a particular time. Zero most hours of the year, and high during system-wide peak hours.

Marginal T&D capacity costs: The capacity cost associated with triggering the construction of a new megawatt of transmission or distribution capacity at a particular time. Zero most hours of the year, and high during peak hours for the infrastructure component that is at capacity.

Operating costs: The ongoing expenses of running and maintaining the electric grid day-to-day. Operating costs recovered from customers in the same year they are incurred.

Peak hours: The hours in a year when a particular infrastructure component — be it a distribution line, transmission line, or the grid as a whole — experiences peak demand. If the component is at capacity, usage during these hours triggers the need for upgrades, which drives delivery costs up.

Peak demand: The maximum current served by a particular electrical infrastructure component during a specified time period, usually a season or year.

Rates: The regulated prices used to calculate customer bills. Includes fixed and volumetric charges.

Residual: The gap between a utility's total revenue requirement and the revenue that marginal-cost pricing alone would recover. It reflects embedded costs — depreciation, carrying charges, O&M — that are not captured by forward-looking marginal costs.

Revenue requirement: The total amount of revenue a utility is authorized to collect from a customer class (or subclass) over a given period, in order to cover its delivery costs. Determined during a rate case.

Rate design: The process of choosing the specific rate structure — the mix of fixed charges, volumetric charges, demand charges, and time-varying prices — used to calculate the bills of a particular group of customers. Many different rate designs can collect the same total revenue, but they differ in their secondary effects.

Seasonal rate: A volumetric rate whose per-kWh price differs between summer and winter but is constant within each season.

Supply costs: The cost to build and maintain power plants, renewables, and batteries, and to operate them to generate electricity. Dominated by energy costs, which vary hour by hour with demand and the mix of generators running.

Time-of-use (TOU) rates: A volumetric rate whose per-kWh price varies by time of day, typically higher during an "on-peak" window when the grid is more likely to be strained and electricity is most expensive to produce, and lower during "off-peak" hours.

Time-varying volumetric rates: Volumetric rates where the price per kWh changes over time. Examples include seasonal rates and time-of-use rates.

Volumetric charges: A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

Findings

WHAT HAPPENS TO HEATING BILLS WHEN HOUSEHOLDS SWITCH TO HEAT PUMPS?

Imagine a single-family home in Syracuse, New York: a three-bedroom ranch-style house built in the 1940s, heated by a natural gas furnace with central air conditioning. It pays $3,048 for electricity and natural gas every year — close to the median total bill for gas-heated homes in the state.[17]

Like all homes in New York, when this household switches to an air-source heat pump,[18] its annual energy use plummets (Figure 1):

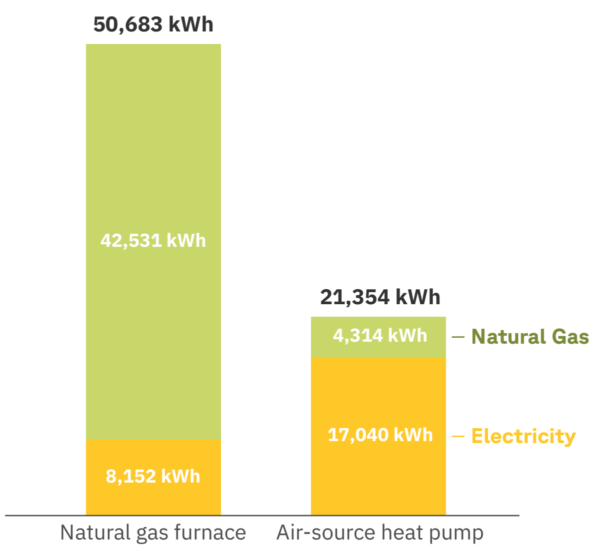


Figure 1: Annual energy consumption before and after switching to a heat pump, for the gas-heated home at the statewide median energy bill (among gas-heated homes with full baseline cooling). 1 kWh of gas = 3,412 BTU.

Heat pumps are 2 to 3 times more efficient than gas furnaces, so they only require a fraction of the energy input to heat a home to the same temperature.

However, while switching to a heat pump cuts a home's energy *use*, it often increases its energy *costs*, as is the case with this Syracuse home (Figure 2).

17 Specifically: a 1,698 sq ft, owner-occupied, single-story home with uninsulated wood-frame walls, an 80% AFUE gas furnace, and SEER 13 central AC. The home is served by National Grid (electricity and gas).

18 The heat pump modeled is a high-efficiency cold-climate air-source heat pump (ccASHP) with electric backup, rated SEER1 20 / HSPF1 11, sized to max load, with 90% capacity retention at 5°F.

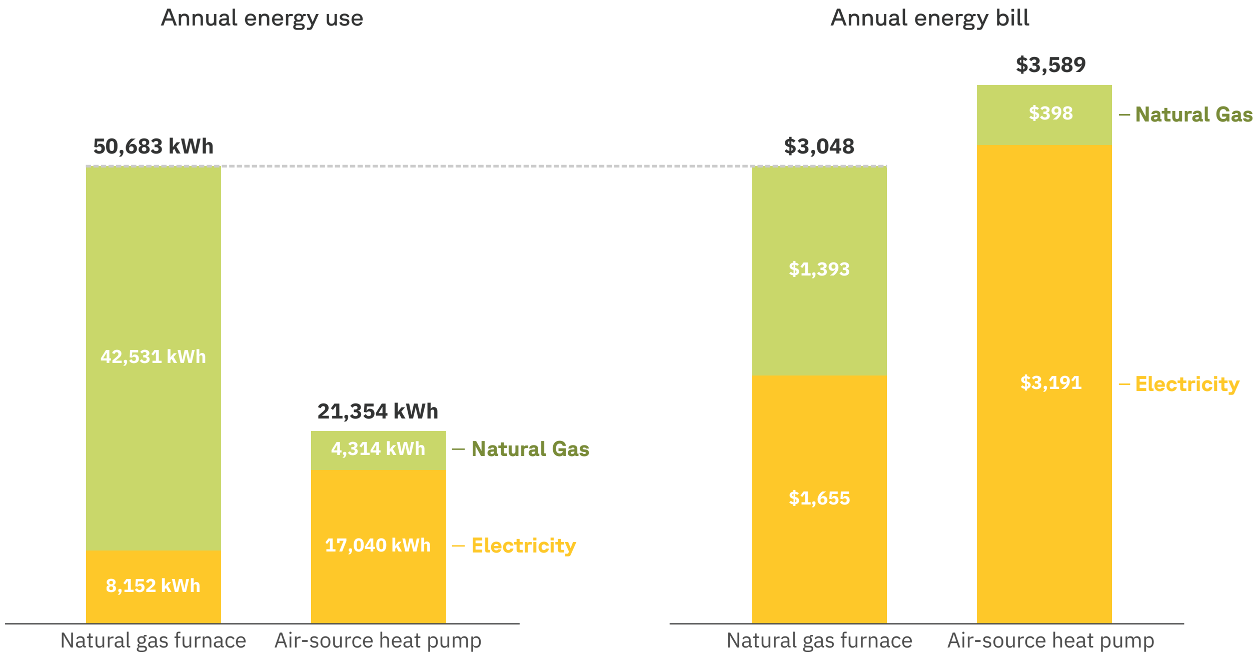


Figure 2: Annual energy consumption and energy bills before and after switching to a heat pump, for the gas-heated home at the statewide median energy bill (among gas-heated homes with full baseline cooling). 1 kWh of gas = 3,412 BTU.

This is because electricity is more expensive than natural gas in New York State: while electricity makes up only 16% of this gas-heated building's total annual energy use, it accounts for 54% of its annual energy bill.

After this building replaces its gas furnace with a heat pump, its annual gas bill drops by $995.[19] But its annual electric bill jumps by $1,536.

The result: despite the heat pump's lower energy use, switching this home's heating fuel from natural gas to electricity causes its annual **combined energy bills** to jump by $541.

In other words, under today's utility rates for electricity and gas, it costs more to heat this home with a heat pump than with natural gas.

19 The home in this example still uses some gas for cooking and hot water, which is why the gas bill doesn't drop to zero after the switch.

While this experience is fairly representative of what happens when gas-heated homes switch to heat pumps today, New York State's building stock is diverse, so the full range of bill impacts varies widely (Figure 3).

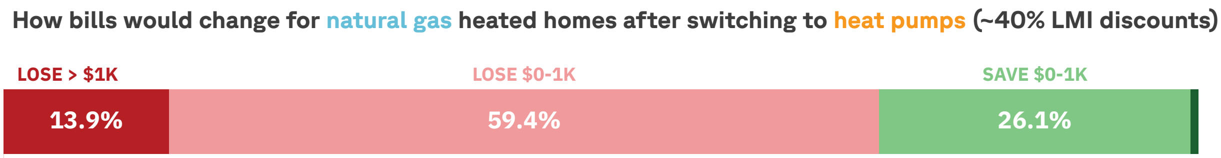


Figure 3: Change in total annual energy bills (electricity + natural gas) for natural gas-heated households that switch to heat pumps (NY, statewide). Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

While most natural gas-heated households that switch to heat pumps do see their bills go up, approximately 27% actually enjoy lower bills after the switch.[20]

While 60% of New York households are heated with natural gas, most of the remainder are heated with delivered fuels or electric resistance — both of which have more potential for bill savings under default rates than natural gas-heated homes (Figure 4).

20 The homes most likely to save under **default rates** are those with less efficient furnaces (they spend more on gas, giving the heat pump a larger bill to offset) and those that have full cooling because the heat pump typically cools more efficiently than the existing AC. See p. 78.

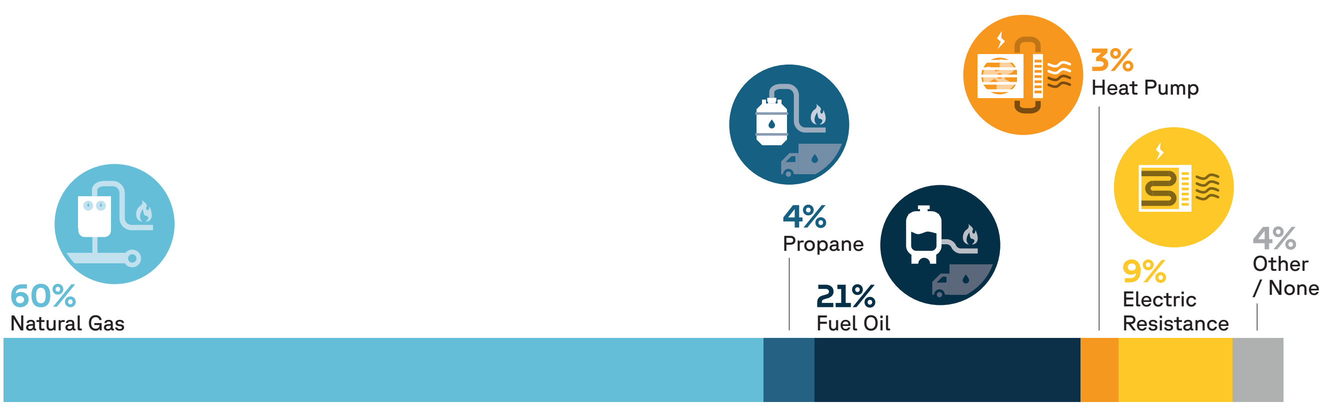


Figure 4: Percentage of NY State households by primary heating fuel

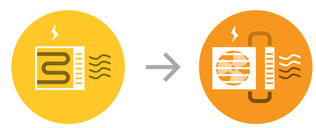
Indeed, when households who heat with delivered fuels (heating oil or propane) switch to heat pumps, their bills tend to go down (Figure 5).

How bills would change for fuel oil or propane heated homes after switching to heat pumps

Figure 5: Change in total annual energy bills (electricity + oil/propane) for oil/propane-heated households that switch to heat pumps (NY, statewide). Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

Today, over 97% of oil and propane households lower their bills after switching, and 48% save more than $1,000 per year.

The story is similar for electric resistance-heated households (Figure 6).



How bills would change for electric resistance heated homes after switching to heat pumps

Figure 6: Change in total annual energy bills for electric resistance-heated households that switch to heat pumps (NY, statewide). Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

For households that heat with electric resistance, 96% would see bill decreases after switching to heat pumps, and 45% would save more than $1,000 per year.

So why do heat pumps struggle to compete against natural gas in New York State?

Low natural gas prices are one significant reason, but not the only one. As we'll see in the next section, the main culprit is the outdated way that utilities charge electric customers for **delivery costs** — the poles and wires that deliver electricity to their homes.

> **Delivery costs**
>
> *The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.*

HEAT PUMP CUSTOMERS ARE CROSS-SUBSIDIZING NON-HEAT-PUMP CUSTOMERS

Why electric bills go up when heat pumps are installed

When a gas-heated household with existing air conditioning switches to a heat pump, its annual electricity consumption goes up by roughly 28% to 93% — and much more for homes that gain cooling for the first time.[21] The electric bill goes up by approximately the same amount.

In the case of the Syracuse home, which had central air conditioning before the switch, its annual electricity use and its annual electric bill both grow by 2.1× (Figure 7).

21 The range shown is the weighted inter-quartile range (25th to 75th percentile) for fossil-fueled homes with full baseline cooling statewide. The increase varies by utility territory and by whether the home already had air conditioning — see p. 80 for a breakdown.

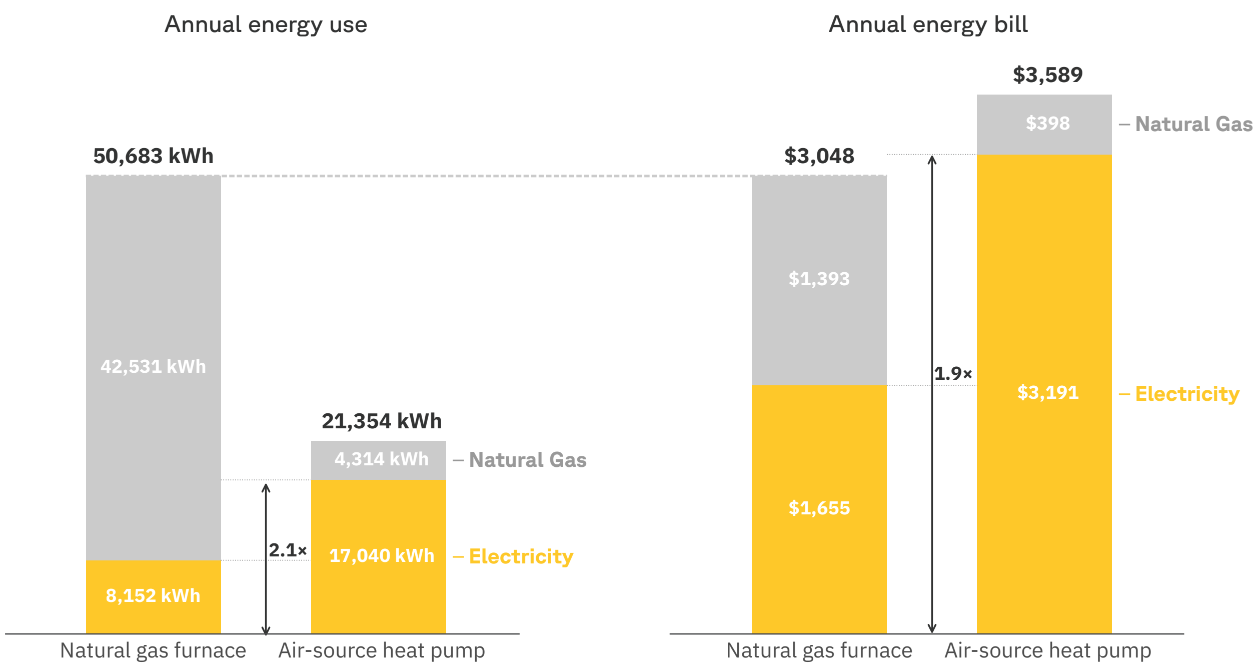


Figure 7: Electricity use and electric bills both grow roughly 2× after switching to a heat pump. 1 kWh of gas = 3,412 BTU.

To understand why this happens, we need to drill down into the electric bill's components (Figure 8).

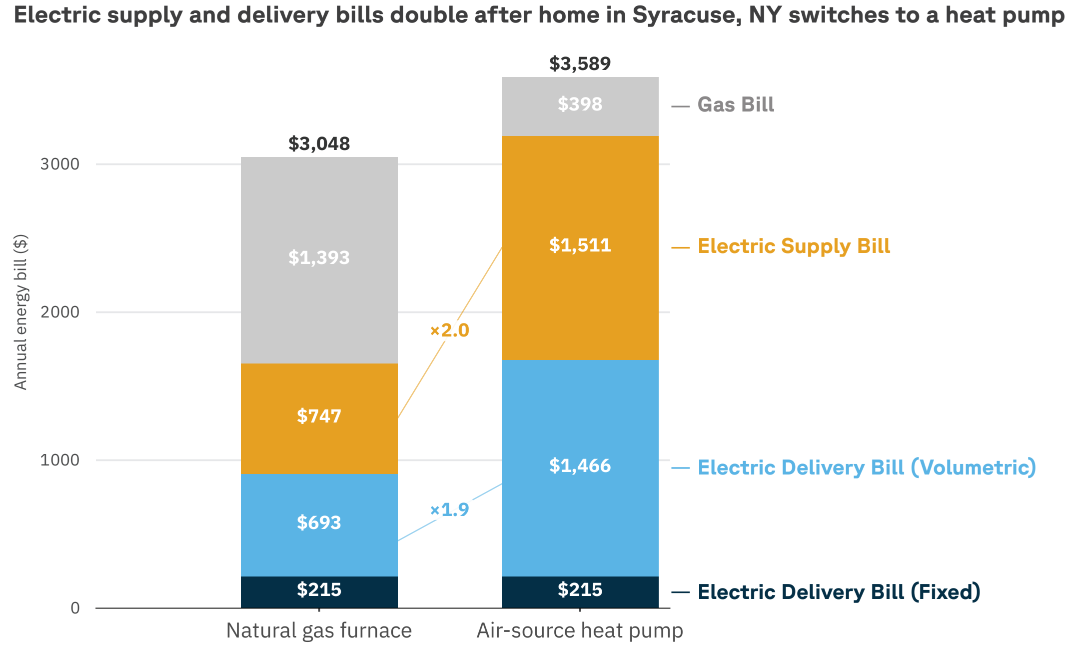


Figure 8: Annual energy bills for Syracuse home, before and after heat pumps, broken down by total gas bill, electric supply bill, and electric delivery bill. The home's annual gas and electricity consumption are from NREL's 2024 ResStock release; bills are calculated using NGrid Upstate's 2025 gas and electricity rates. Electricity bill includes supply and delivery surcharges but excludes reconciliation and other true-up charges.

The home pays 2.0× as much for electricity supply after switching to a heat pump — the part of the bill that pays for the electricity itself, and for power plants to be available to generate it. This makes sense: after making the switch, the home consumes 2.1× as much electricity per year.

But upon turning on the heat pump, the home also starts paying 1.9× more for the same poles and wires that bring that electricity to their home.

This happens because delivery costs are largely recovered through volumetric rates, rather than **fixed charges**. The result: when a customer consumes more electricity, not only do they pay more for that electricity, but they also pay more for the grid itself — regardless of whether they trigger the need for grid upgrades.

Is this delivery bill inflation fair?

Heat pump customers are overpaying for delivery

Utility regulators generally hold the principle that to be fair, a customer's **bill** must match the **costs** the customer imposes on the system.[22]

When a customer increases their electricity use after installing a heat pump, they increase their supply costs — power plants have to burn more fuel to generate that electricity, and so on. So it makes sense that their supply bill also grows.[23]

But a customer's delivery bill should only grow if they cause new delivery costs, thereby growing their delivery cost of service. And this only happens when their new electricity use triggers new upgrades to the grid's capacity — during the handful of "peak hours" of the year, when the grid as a whole (or their local distribution network) is most congested.

If a customer's delivery bill exceeds their delivery cost of service, they are overpaying.

To illustrate, let's return to our Syracuse home, which is served electricity by National Grid, and has an annual delivery cost of service of $934 per year (Figure 9).

When heated with natural gas, the home's annual electric delivery bill is $26 lower than its delivery cost of service — a good illustration of how most gas-heated homes actually underpay for electric delivery.

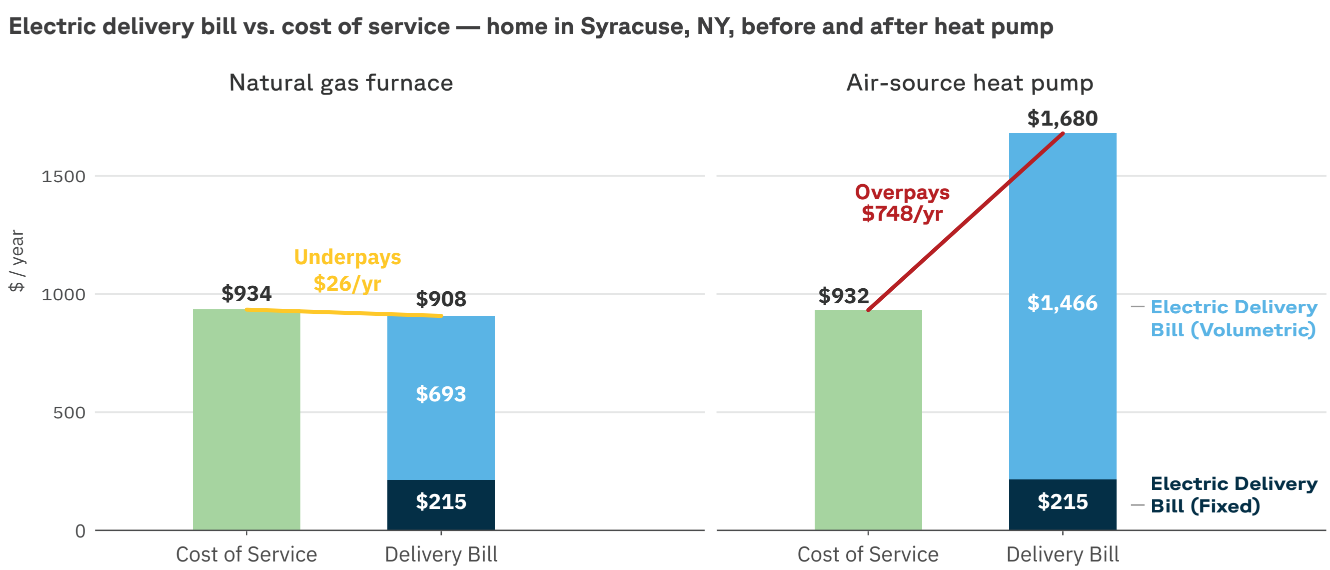
22 This is commonly called the **cost-causation principle**, and it originates in the sixth of the eight Bonbright principles of a sound rate structure: *"Fairness of the specific rates in the apportionment of total costs of service among the different consumers."* (Bonbright 1961).

23 For an introduction to supply and delivery bills, costs, and cost-of-service, see the Background section on p. 9.

Supply costs

The cost to build and maintain power plants, renewables, and batteries, and to operate them to generate electricity. Dominated by energy costs, which vary hour by hour with demand and the mix of generators running.

Figure 9: Annual electric delivery bill vs. delivery cost of service for the home in Syracuse, NY, before and after switching to a heat pump. Home's electric loads are from ResStock, bills are calculated using NGrid Upstate's 2025 electric rates. Cost-of-service is from Switchbox analysis of T&D marginal costs and utility revenue requirements.



After switching to the heat pump, this particular home's electric delivery cost of service is unchanged, because its new electricity use is highly concentrated in the winter, when the transmission and distribution network has plenty of spare capacity, and therefore usage does not trigger the need for grid upgrades.[24]

But as we saw earlier — as a direct consequence of volumetric rates — the Syracuse home's annual electric delivery bill grows to $1,680 per year, causing an overpayment of $748 per year.

How widespread is this overpayment problem in practice?

We find that households with heat pumps are systematically paying more than their cost of service for electric delivery across New York State.

Statewide, the electric delivery cost of service for electric customers that heat with heat pumps is $1,086, on average, compared to $1,060 for electric customers that heat with natural gas, just **2%** higher.

But the electric delivery bills that heat pump customers currently pay are **109%** higher than those of electric customers that heat with natural gas, on average.

New York State's heat pump customers are overpaying by an average of $855 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	2.7%	6.0%	15,669 kWh / year	$1,940 / year	$1,086 / year	$855 / year	78.7%
Electric resistance	9.0%	18.7%	14,917 kWh / year	$1,945 / year	$1,072 / year	$873 / year	81.4%
Natural gas	59.6%	48.0%	5,793 kWh / year	$930 / year	$1,060 / year	−$131 / year	−12.3%
Delivered fuels	24.9%	24.0%	6,929 kWh / year	$1,038 / year	$1,113 / year	−$75 / year	−6.8%
Other	3.7%	3.3%	6,296 kWh / year	$912 / year	$1,060 / year	−$148 / year	−13.9%
All customers	100.0%	100.0%	7,188 kWh / year	$1,075 / year	$1,075 / year	$0 / year	0.0%

Total customer count from 2024 EIA-861, subclass customer counts estimated using RECS 2020. Building loads and utility assignments from ResStock. Cost-of-service from Switchbox analysis.

Table 1: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer subclass, under default rates. Assumes lump-sum residual allocation (equal residual share for all customers).

We find that heat pump customers are overpaying for delivery by **$855 per year**, on average.

24 In other words, when **marginal T&D capacity costs** are zero. The fact that the home's electricity use grew by 109%, but its delivery cost of service did not change, reflects the ample winter headroom in the NYISO grid as a whole and in National Grid's distribution network in particular. (see p. 51).

Volumetric rates

A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

Cost of service

*The costs associated with generating and delivering electricity to a particular customer or customer class. A customer's **delivery** cost-of-service is their fair share of delivery costs; **supply** cost-of-service is their share of supply costs.*

Note

To see how heat pump overpayments vary by utility, see p. 101.

Simultaneously, households that heat with natural gas are *underpaying* for electric delivery relative to their delivery cost of service by **$131 per year**, on average, while those with heating oil and propane are *underpaying* by **$75 per year**.

These findings are connected: part of what allows electric customers that heat with fossil fuels to pay less for electric delivery than their cost of service is precisely the fact that heat pump customers are overpaying, which creates a **cross-subsidy** to customers that heat with fossil fuels.[25]

Cross-subsidy

The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group..

25 **Electric resistance** customers are also overpaying, and are responsible for a substantial portion of the cross-subsidy to customers that heat with natural gas and heating oil and propane.

How overpayments create cross-subsidies

To understand how cross-subsidies arise, let's return to the single-family home in Syracuse.

Before switching to a heat pump, let's assume its annual electricity use, and therefore its annual delivery bill, is the same as those of its natural gas-heated neighbors.

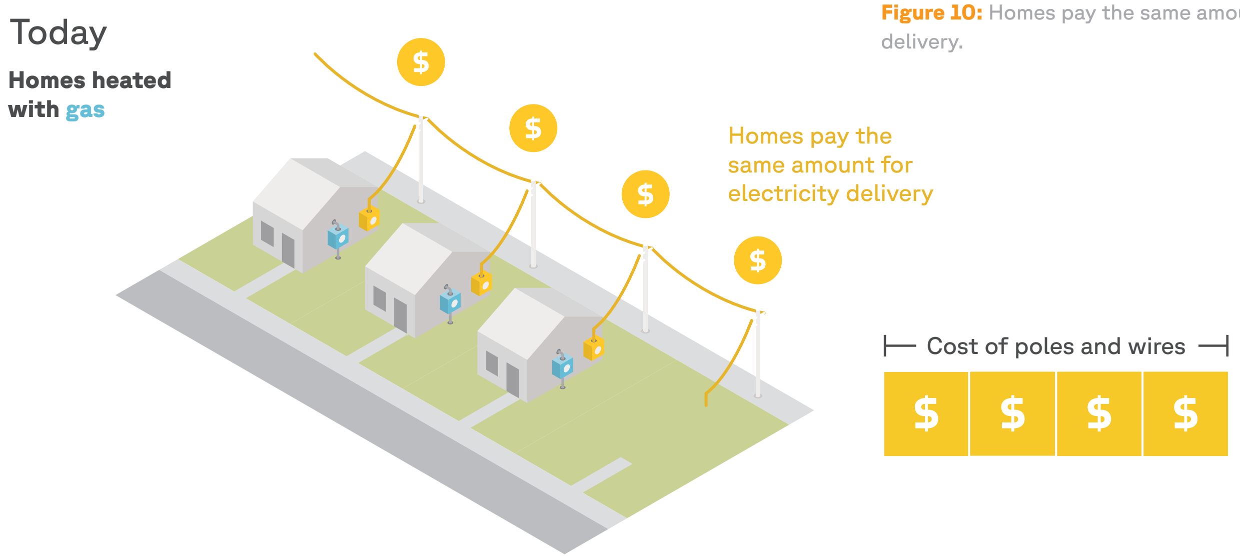


Figure 10: Homes pay the same amount for delivery.

The power line on this block was upgraded in recent years, and the cost of this upgrade is paid back by all electric utility customers over decades. Every year, a portion of the cost of this upgrade is paid for by the homes on this block.[26]

As we've seen, after the home installs a heat pump, its annual electricity use (and therefore its annual delivery bill) both grow by 2.1×. But this new electricity use is highly concentrated in the winter. In fact, the Syracuse home's summer electricity use would actually *decline*, because the heat pump cools more efficiently than the home's prior air conditioner:

26 In practice, these customers would also help pay for other power lines, and customers on other blocks would help pay for this one. This is a stylized example to illustrate the zero-sum dynamic: the utility's annual **revenue requirement** is fixed, so under volumetric rates, any customer who consumes more electricity pays a larger share of that fixed pot — and everyone else pays a smaller share, regardless of whether the actual cost of serving anyone changed.

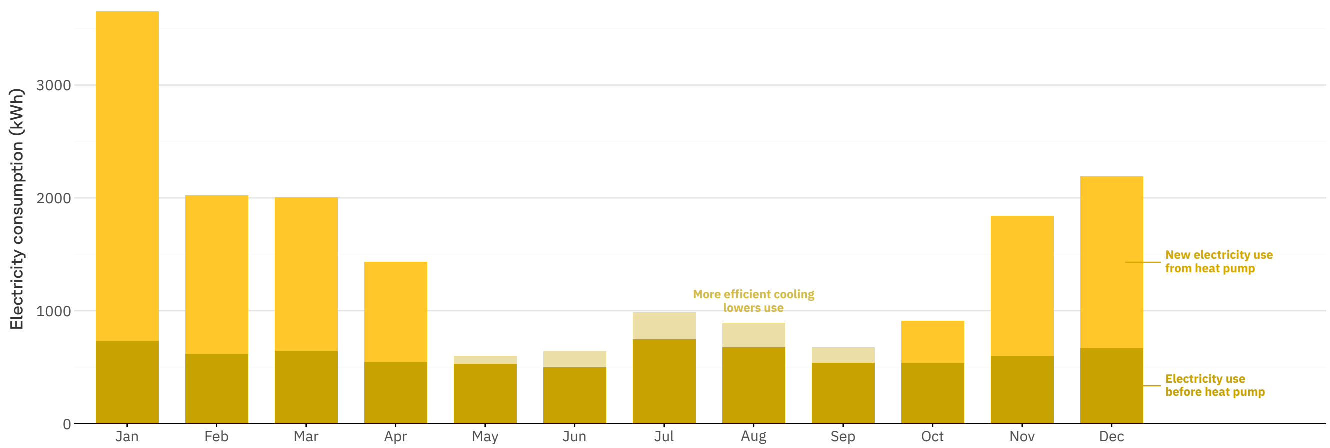
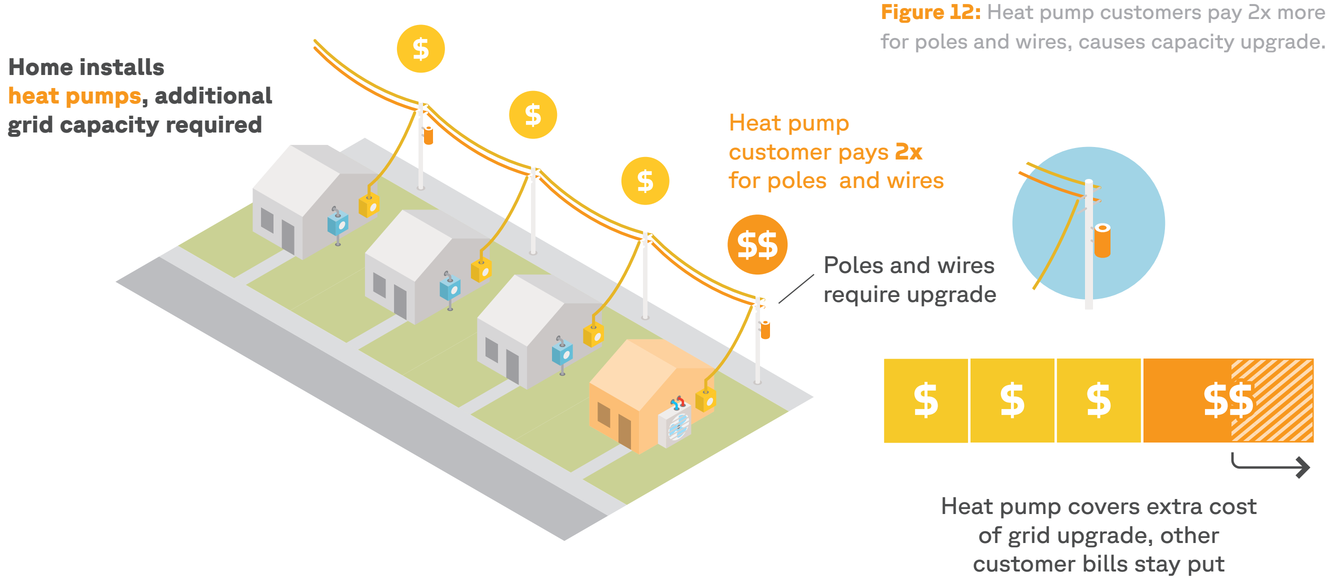


Figure 11: Monthly electricity consumption for Syracuse home, before and after installing a heat pump. Home heated by gas furnace and cooled by central AC before the switch. After the switch, winter electricity use grows sharply, while summer use falls because heat pumps cools more efficiently than old AC unit.

Does the power line have enough capacity to accommodate this additional wintertime load?

If it does not, the electrical utility would need to upgrade the power line.

Figure 12: Heat pump customers pay 2x more for poles and wires, causes capacity upgrade.



These new **delivery costs** (represented by the growth in rectangle in the diagram above) must now be recovered from the customers.

The costs were caused by the heat pump installation, so under the principle of **cost-causation**, they should be borne by that customer.

And, in this case, they are: the higher delivery bills resulting from volumetric delivery rates cover these additional delivery costs. The customer's delivery **cost of service** grows, but the delivery bill grows to match it. There's no underpayment or overpayment, and no impact on the other customers on the block.

But as we'll see in p. 51, the overwhelming majority of New York's grid *does* have the **capacity** to accommodate this additional wintertime load.

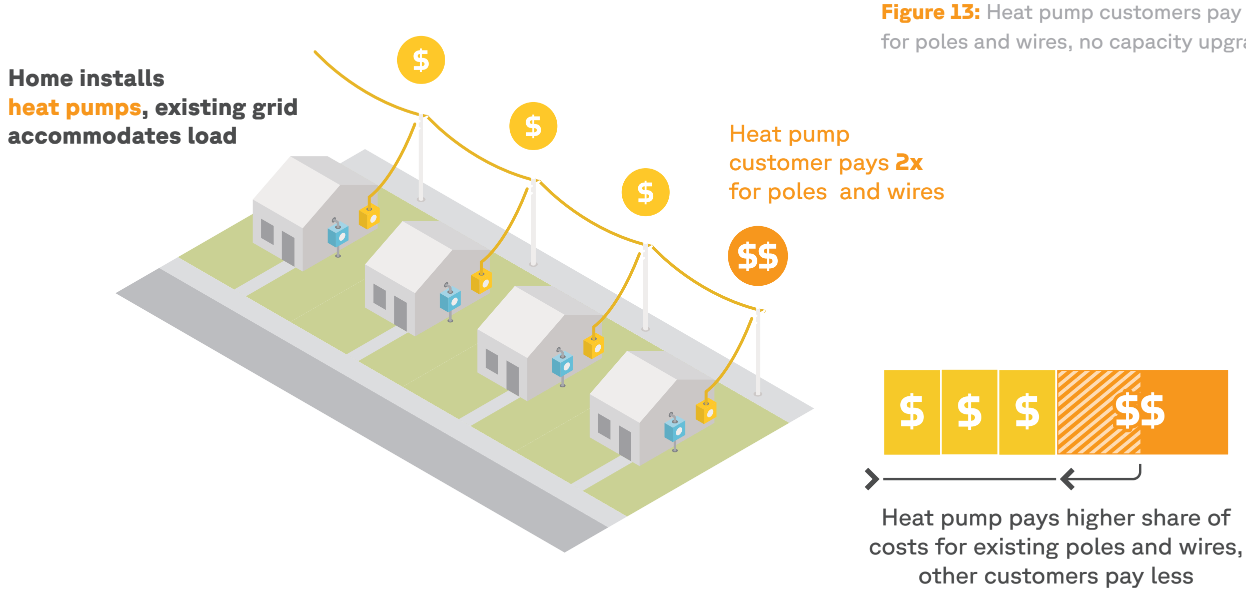
Delivery costs

The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.

Capacity (infrastructure)

The maximum electric current a piece of transmission or distribution equipment — a line, transformer, or substation — can carry safely without damaging the equipment. When demand approaches an asset's capacity, the utility must either upgrade it, or build new infrastructure to handle the load.

Figure 13: Heat pump customers pay 2x more for poles and wires, no capacity upgrade.



In this more common scenario, the power line's spare winter capacity absorbs the heat pump's additional winter load without needing any upgrades. **Delivery costs** don't grow; they stay fixed.

Volumetric rates cause the heat pump customer's delivery bill to rise, despite the fact that their delivery cost of service hasn't changed. The heat pump customer pays a bigger share of the fixed costs, which allows the other customers on the block (and throughout the utility territory) to pay less.[27]

And this "no capacity upgrade" scenario is the one that prevails across most of the state today (see p. 51).

27 In practice, this redistribution operates on a lag. Each of New York's major investor-owned electric utilities is authorized to collect a fixed delivery **revenue requirement**, set in its last rate case, and operates under a **revenue decoupling mechanism** that reconciles actual delivery revenue against that target. When heat pump customers' additional winter consumption pushes realized delivery revenue above the target, the over-collection is refunded to all residential customers in the following year via a per-kWh bill credit. The same rebalancing plays out more structurally at the next rate case, when higher realized sales divide a roughly fixed revenue requirement into a lower per-kWh delivery rate. Through both mechanisms, heat pump customer overpayments pull delivery rates down for everyone on the system, all else equal. Non–heat pump customers' bills shrink as a result. Heat pump customers' bills shrink too — but because they consume several times more electricity than their fossil-heated neighbors, their bills remain far above their cost of service, while those of customers who heat with fossil fuels sink below theirs.

THE TRUE DELIVERY COST-OF-SERVICE OF HEAT PUMP CUSTOMERS

So far, we have examined the cross-subsidy problem one household at a time: the average heat pump customer overpays for delivery by **$855** per year. But what does this add up to across the state?

Heat pump customers currently make up just **2.7%** of New York's residential electricity customers, but they contribute **4.9%** of total delivery revenue. These customers consume considerably more electricity per household than others customers — approximately **2.7x** more on average than homes that heat with natural gas — and under volumetric delivery rates, they pay accordingly (Table 2).

Residential electric customers with heat pumps make up 2.7% of customers but pay 4.9% of delivery revenue

Heating source	Customers	% of customers	Consumption	% of consumption	Delivery revenue	% of revenue
Heat pump	198,368	2.7%	3,108 GWh / year	6.0%	$384,899,435 / year	4.9%
Electric resistance	654,504	9.0%	9,763 GWh / year	18.7%	$1,272,846,885 / year	16.3%
Natural gas	4,321,803	59.6%	25,036 GWh / year	48.0%	$4,017,123,506 / year	51.5%
Delivered fuels	1,807,506	24.9%	12,524 GWh / year	24.0%	$1,876,043,206 / year	24.1%
Other	269,757	3.7%	1,698 GWh / year	3.3%	$246,142,327 / year	3.2%
All customers	7,251,938	100.0%	52,130 GWh / year	100.0%	$7,797,055,359 / year	100.0%

Table 2: Total residential customers, electricity consumption, and delivery revenue by heating source, statewide, under each utility's default rate. Total customer counts are from EIA form-861, subclass customer counts are derived from RECS 2020, total revenue is derived from utility rate cases and 2025 delivery rates, subclass consumption comes from ResStock 2024 loads, subclass revenue comes from Switchbox bill calculations, using 2025 utility delivery rates (fixed and volumetric) applied to ResStock loads geographically assigned to each utility.

But how much of the revenue paid by heat pump customers across New York State — $385 million a year — is justified by the actual cost of serving them?

Table 3 adds the key comparison needed to answer this question: the total delivery cost of service for each of these residential customer groups, alongside the revenue utilities currently collect from them.

New York State's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $169 million a year

Heating source	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	2.7%	6.0%	$384,899,435 / year	4.9%	$215,353,389 / year	2.8%	$169,546,046 / year	78.7%
Electric resistance	9.0%	18.7%	$1,272,846,885 / year	16.3%	$701,731,096 / year	9.0%	$571,115,788 / year	81.4%
Natural gas	59.6%	48.0%	$4,017,123,506 / year	51.5%	$4,581,460,345 / year	58.8%	−$564,336,839 / year	−12.3%
Delivered fuels	24.9%	24.0%	$1,876,043,206 / year	24.1%	$2,012,502,579 / year	25.8%	−$136,459,373 / year	−6.8%
Other	3.7%	3.3%	$246,142,327 / year	3.2%	$286,007,950 / year	3.7%	−$39,865,623 / year	−13.9%
All customers	100.0%	100.0%	$7,797,055,359 / year	100.0%	$7,797,055,359 / year	100.0%	$0 / year	0.0%

Total customer count from 2024 EIA-861, subclass customer counts estimated using RECS 2020. Building loads and utility assignments from ResStock. Cost-of-service from Switchbox analysis.

Table 3: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass, statewide, under each utility's default rate. Assumes lump-sum residual allocation (equal residual share for all customers). Subclass cost-of-service calculated using NREL's CAIRO model, applied to: a. utility-level revenue requirements, b. ResStock 2024 loads (assigned to each utility based on geographic location), c. zonal marginal transmission costs from NYISO, and d. marginal distribution costs from each utility's 2025 MCOS study. Full details available in methods section.

Across the state, heat pump customers are overpaying for delivery by a total of approximately **$170 million per year** — the gap between what utilities collect from them and what it actually costs to serve them.

This gap points to a fix that is more fundamental than designing a new rate.

Utilities already perform **cost allocation** between customer classes — residential, commercial, industrial, and so on. For each class, the utility measures the cost of serving that group and assigns a **revenue requirement**: a target amount to collect that matches the group's **cost of service**.[28]

But utilities do not currently perform cost allocation at the level of customer *subclasses* within the residential class. All residential customers — whether they heat with gas, oil, or a heat pump — are lumped into a single group and charged the same **default rate**.

Whatever revenue that rate happens to collect from each subclass is whatever it collects; the utility doesn't track whether it overshoots or undershoots any subclass's cost of service, because it has no reason to. Which is exactly what happens to heat pump customers: the default **volumetric** rate collects far more from them than it costs to serve them, and the utility has no visibility into the mismatch.

A simple way to close this gap is to calculate the delivery cost of service for these heat pump customers — $215M per year statewide, at present — and calibrate a delivery rate to collect exactly that amount from them — no more, no less.[29]

To model rates that would eliminate the **cross-subsidy**, then, we apply the following method to each utility:[30]

1. **Cost allocation**: determine the correct revenue to collect from the heat pump customers served by that utility.

2. **Rate design**: choose among the many rates that could collect this revenue. A lower **flat rate**, a higher **fixed charge**, a **seasonal rate**, a **time-of-use rate** — any rate calibrated to collect the revenue dictated by the cost allocation will, by definition, eliminate the cross-subsidy and solve the **fairness** problem, though these rates may have different secondary effects: on equity across income levels, **economic efficiency**, incentives for conservation or distributed generation, and so on.

Revenue requirement

The total amount of revenue a utility is authorized to collect from a customer class (or subclass) over a given period, in order to cover its delivery costs. Determined during a rate case.

28 Our analysis is based on each utility's existing customer class cost allocation. We go one step further, performing cost allocation *within* the residential customer class to estimate the cost of service of heat pump customers. A utility implementing a heat pump rate would not need to change its existing embedded cost-of-service study or cost allocation process; it would just need to measure the cost of service for heat pump customers specifically.

Cost allocation

*The regulatory process of dividing a utility's total revenue requirement among the groups of customers it serves, in proportion to each group's cost of service. Typically applied to broad customer classes (residential, commercial, etc.); can also be performed for groups **within** a class (e.g. heat pump customers).*

29 This is the same calculation a utility would perform if it were to create a dedicated **rate class** for heat pump customers in order to offer heat pump rates: determine the subclass's actual cost of service, set a revenue requirement that reflects it, and choose a rate structure that collects it.

30 This is how ratemaking works: rate design is always based on cost allocation. First, the utility determines how much revenue to collect from a group of customers, based on their cost of service. Then, it chooses among rate structures that all collect this amount but may have different secondary effect. To create the rates in this report, we are simply applying this process *within* the residential customer class.

> **Utility-level cost allocation**
>
> For the details of our utility-level cost allocation exercise — including the number of heat pump customers, their collective delivery cost of service, and the revenue the utility should aim to collect — see p. 83.

Cost-based rate

A rate that bills a group of customers in line with their cost of service. Cost-based rates solve the fairness problem: the average customer in the group, and the group as a whole, neither overpays nor underpays relative to what it costs to serve them.

Cost allocation determines *how much* to collect from each customer group. Rate design simply determines *how* to collect it. **Getting the cost allocation right is what eliminates the cross-subsidy.** The choice among alternative cost-based rate designs that all collect "the right amount" is then largely about balancing other impacts (equity, efficiency, and so on).[31]

31 In other words, under tech-specific rates, fairness is not an intrinsic property of a rate's structure — it comes from the subclass-specific revenue target the rate is designed to hit. A seasonal rate that collects the wrong revenue requirement, for instance, wouldn't be cost-based.

	Eligibility	Rates affected	Design	Cost-based	Cost-reflective	Discussed on page
1. Dedicated heat pump delivery rate	heat pump customers	delivery only	seasonal	✔	✘	p. 30-40
2. Electric heating delivery rate	heat pump and electric resistance customers	delivery only	seasonal	✔	✘	p. 41-45
3. Time-of-use heat pump rate	heat pump customers	delivery and supply	seasonal time-of-use	✔	✔	p. 46-51

In this report, we model two rate designs that would collect heat pump customers' true cost of service: a dedicated heat pump delivery rate, and a more cost-reflective time-of-use heat pump rate that would additionally help heat pump customers shift usage away from peak hours.

We also model a dedicated electric heating rate that would additionally collect the true cost of service of electric resistance customers, which utilities are also overcharging.

RATE DESIGN 1: A DEDICATED HEAT PUMP DELIVERY RATE

Having determined the appropriate delivery revenue requirement for heat pump customers at each utility, the next question is how to collect it.

Seasonal rate

A volumetric rate whose per-kWh price differs between summer and winter but is constant within each season

We design simple **seasonal rates** for every utility in New York State. These are *delivery* rates that would only be available to heat pump customers — their supply bills would remain unchanged.

	ConEd	NiMo	NYSEG	CenHud	RG&E	O&R	PSEG-LI
Summer delivery rate (¢/kWh)	15.58	8.63	10.27	14.61	7.09	11.84	10.23
Winter delivery rate (¢/kWh)	5.21	1.89	2.75	2.59	1.33	3.60	2.44
Winter discount	66.6%	78.1%	73.2%	82.3%	81.2%	69.6%	76.2%

Table 4: Proposed seasonal heat pump rate, per utility. Summer rates match current default rate (when default rate is flat), winter rates are reduced to align heat pump customers' annual bills with their cost-of-service. Default delivery rates in ConEd, O&R, and PSEG-LI are not flat — Switchbox derived flat rates for these utilities as a starting point.

In summer (April through September), the **volumetric** delivery rate would equal the utility's current **default rate** — so no heat pump customer pays more in summer than they do today. In winter (October through March), delivery rates would be significantly lower than they currently are — between 67% and 82% lower, depending on the utility.[32]

Each of these delivery rates is cost-based: the winter delivery rate applied to heat pump customers in a utility's territory is lowered until the annual revenue collected from them as a group equals their annual cost-of-service.

This is the same seasonal rate design currently offered by investor-owned utilities in Massachusetts.[33]

Massachusett's seasonal heat pump rates

Pursuant to a series of orders from MA's Department of Public Utilities (DPU), Eversource, National Grid, and Unitil began offering these seasonal heat pump rates to residential customers on November 1, 2025 (DPU 2025). MA's state energy office has petitioned the DPU to adopt a lower winter rate for these tariffs in the 25-08 docket (DOER 2025). Switchbox's analysis of these MA rates is available here (Murray and Velez 2025).

These rates would lower heat pump customer delivery bills in every winter month while keeping summer bills the same — so every heat pump customer would be *guaranteed* to pay the same or less on their monthly delivery bill after switching to the dedicated rate than they do today.[33]

32 Because we don't lower summer rates in this design, the entire reduction needed to bring annual delivery revenue from heat pump customers in line with their **cost allocation** must come from winter, which is why winter delivery rates are so low.

33 MA's Department of Public Utilities (DPU) originally chose this design so that utilities could auto-enroll all electric customers who have received an upfront rebate to install a heat pump through the MassSave program into the heat pump rates, without any additional action on their part.

IMPACT OF DEDICATED HEAT PUMP DELIVERY RATE ON THE CROSS-SUBSIDY

If all existing heat pump customers adopted these dedicate delivery rates, what would happen to the overpayments and underpayments we saw earlier?

Heat pump rate eliminates cross-subsidy from electric customers with heat pumps to those who heat with fossil fuels

		All customers on utility's default rates		HP customers on hp seasonal rate; non-HP customers on adjusted default rate			
Heating source	Avg. cost of service	Avg. delivery bill	Avg. cross-subsidy	Change in avg. delivery bill	Avg. delivery bill	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	$1,086 / year	$1,940 / year	$855 / year	−$855 / year	$1,086 / year	$0 / year	0.0%
Electric resistance	$1,072 / year	$1,945 / year	$873 / year	$55 / year	$2,000 / year	$928 / year	86.5%
Natural gas	$1,060 / year	$930 / year	−$131 / year	$19 / year	$949 / year	−$111 / year	−10.5%
Delivered fuels	$1,113 / year	$1,038 / year	−$75 / year	$24 / year	$1,062 / year	−$52 / year	−4.7%
Other	$1,060 / year	$912 / year	−$148 / year	$25 / year	$938 / year	−$123 / year	−11.6%
All customers	$1,075 / year	$1,075 / year	$0 / year	$0 / year	$1,075 / year	$0 / year	0.0%

Table 5: Average electric delivery bill, delivery cost of service, and cross-subsidy by heating fuel type, under two sections: 1. all customers under each utility's current default rates and 2. all heat pump customers on utility's HP seasonal rate and all other customers on utility's adjusted default rate. Assumes lump-sum residual allocation (equal residual share for all customers).

Because the dedicated delivery rates are calibrated to each utility's heat pump revenue requirement, they collect the correct annual delivery revenue from heat pump customers in each territory — $1,086 per year, on average, statewide — eliminating their overpayment by design.

By eliminating the cross-subsidy from heat pump customers to customers that heat with fossil fuels, the underpayments of natural gas, propane, and heating oil customers would decrease, on average — from -$131 to -$111 per year for natural gas, and from -$75 to -$52 for heating oil and propane.[35]

The dedicated heat pump delivery rate eliminates the cross-subsidy — that's what cost allocation guarantees. But does charging heat pump customers fairly move the needle on their bills?

34 Even if utilities stopped overcharging all heat pump customers, electric customers who heat with fossil fuels would still be underpaying for delivery, unless electric resistance customers also stopped being overcharged. We model this scenario on p. 41.

BILL IMPACT OF DEDICATED RATE ON HEAT PUMP CUSTOMERS

If our dedicated heat pump delivery rate were available, how would it affect what happens to annual energy bills when natural gas heated households switch to heat pumps? Let's revisit our earlier analysis.

First, let's return to the post-heat pump bills for the Syracuse home.

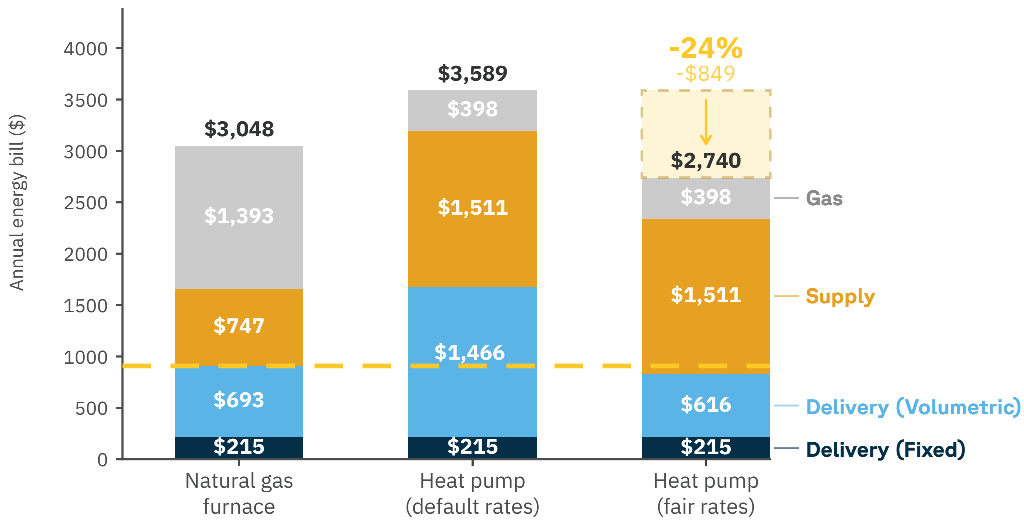


Figure 14: Annual energy bill for the representative gas-heated home in Syracuse: before heat pumps under default rates, after heat pumps under default rates, and after heat pumps under seasonal heat pump rates. Assumes National Grid Upstate's default gas / electric delivery and supply rates from 2025.

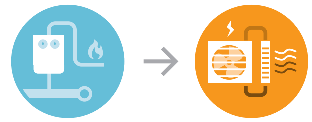
Under the heat pump rate, the Syracuse home's post-heat pump annual electric bill would drop by **24%** — from $3,589 under default rates to **$2,740**.

The savings come entirely from the electric volumetric delivery component, which shrinks thanks to the lower winter volumetric rate — 1.89 c/kWh in National Grid, down from 8.63 c/kWh. Electric supply and gas bills are unchanged.

The dashed line marks the home's pre-heat-pump delivery bill. Under the dedicated delivery rate, the post-heat-pump delivery bill falls close to it — meaning the overpayment for delivery has been largely eliminated for this home.

Bottom line: the dedicated heat pump delivery rate would lower the Syracuse home's heat pump operating costs (compared to default electric delivery rates) by **$849**, and ultimately allow it to save **$308** per year by switching from gas heating to heat pumps.

Would we see similar outcomes statewide? Let's zoom out and take a look. Figure 15 shows how the total annual energy bills (both gas and electric) of gas-heated households would change after switching to heat pumps — under both the default delivery rates that overcharge them, and the dedicated heat pump delivery rates that would eliminate the overpayment.



How bills would change for natural gas heated homes after switching to heat pumps

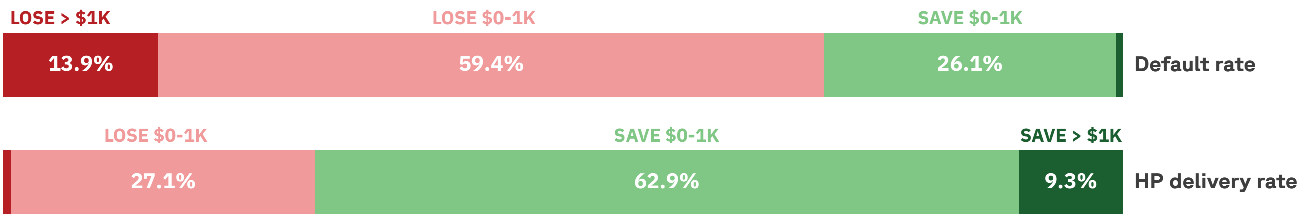


Figure 15: Change in total annual gas + electric bills — natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate (NY, Statewide). Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

Cost-based heat pump delivery rates would transform the economics of heat pumps in New York State.

Under default rates, only **27%** of gas-heated households would save by switching to heat pumps. But under the dedicated heat pump delivery rate, **72%** of gas-heated households would save. And the share of households losing over $1,000 per year would drop from 14% to just 1%.

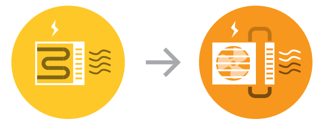
The fact that most gas-heated households would save by switchin the heat pumps if utilities stopped overcharging them demonstrates that heat pump operating costs struggle to compete against natural gas largely because of outdated volumetric delivery rates — not cheap gas supply.

The pattern holds for oil and propane-heated homes. Under default rates, 97% of oil/propane households would save by switching to heat pumps. Under dedicated heat pump delivery rates, **100%** would save.

Figure 16: Change in total annual energy bills — oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate (Statewide). Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump

How bills would change for fuel oil or propane heated homes after switching to heat pumps

Electric resistance homes see a similar improvement. Under default rates, 96% would save by upgrading to heat pumps. Under dedicated heat pump delivery rates, **99%** would save.



How bills would change for electric resistance heated homes after switching to heat pumps

Figure 17: Change in total annual energy bills — electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate (Statewide). Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

EQUITY IMPACT OF DEDICATED HEAT PUMP DELIVERY RATE

While the bill impacts shown above reveal how the population at large would be affected by our modeled dedicated heat pump delivery rates, they don't illuminate the equity impact on low- and moderate-income (LMI) households. For that, we must zoom in on this population and look at energy burdens.

Today, 47% of New York's LMI households that heat with natural gas spend more than 6% of their annual income on energy bills, and are therefore considered to be **highly energy burdened.**[35]

This figure reflects current LMI gas and electric bill discounts provided through the utilities' Energy Affordability Program (EAP) and Enhanced Energy Affordability Program (EEAP); only ~40% of eligible LMI households are currently enrolled in these programs.[36]

Energy burden

Energy burden is defined as the percentage of a household's annual income spent on energy bills.

35 6% is a common threshold for "high energy burden" in energy affordability research. It is based on the standard definition of housing affordability: to avoid financial strain, households should spend no more than 30% of their income on housing. LMI households typically spend around 20% of their housing costs on energy. Putting these facts together suggests 6% (30% x 20%) as good threshold for energy affordability. See NYSERDA's Affordability Gap report for a full discussion (NYSERDA 2011).

36 We define LMI households as those eligible for New York's EAP and EEAP programs — generally, households with income at or below 100% of State Median Income (or Area Median Income in Con Edison and KeySpan territories). See p. 135 for the full tier structure and how we assign eligibility in our simulation.

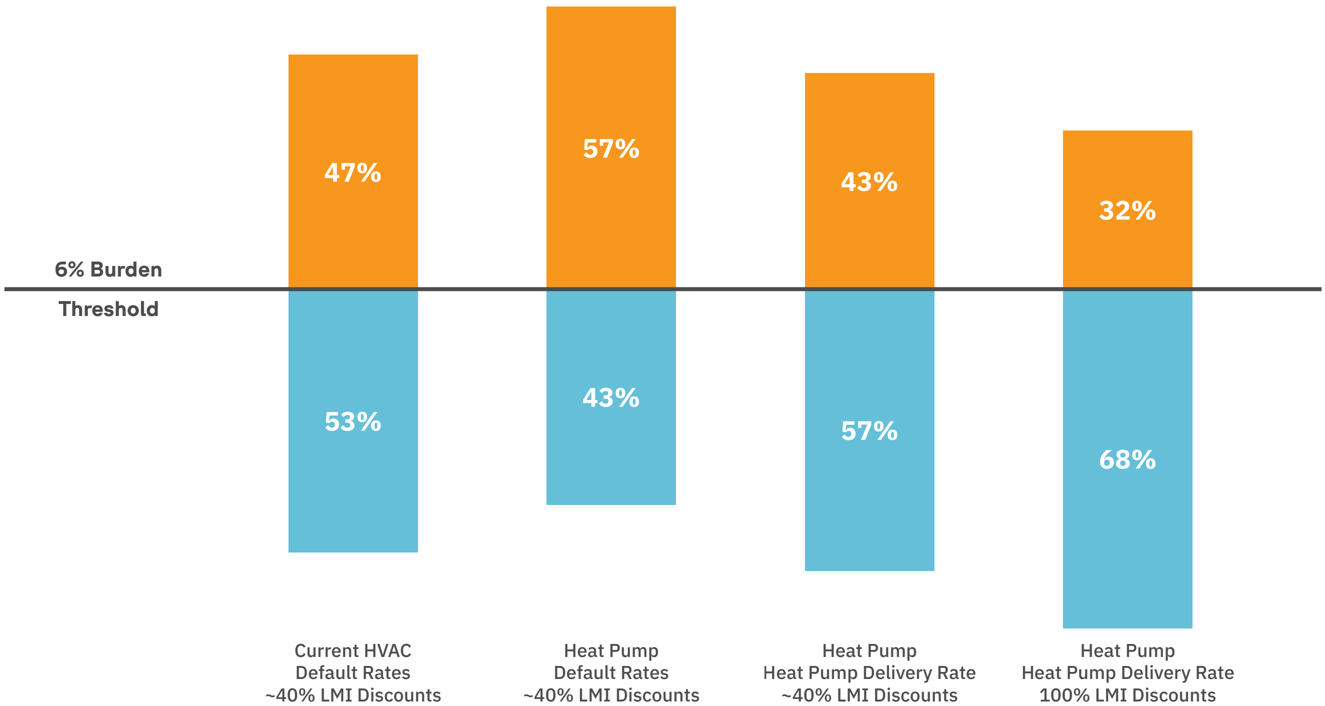
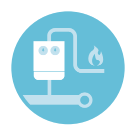


Figure 18: Share of low-income gas-heated households above the 6% high energy burden threshold



After installing heat pumps under default rates, **57%** of gas-heated LMI households would be highly energy burdened — an increase of 10 percentage points. (This assumes that the same households that are already enrolled in a utility EAP remain enrolled after switching to heat pumps.)

If these same gas-heated households installed heat pumps but instead enrolled in the dedicated heat pump delivery rate, 43% of them would be highly burdened — a decrease of 4 percentage points compared to heating with gas.

We also model a scenario in which every gas-heated LMI household is enrolled in their utility's EAP programs at the time of heat pump installation — not just those already enrolled today.

The final bar in Figure 18 shows what post-heat pump installation burdens would look like under this scenario — dedicated heat pump rate adoption plus full EAP enrollment. The number of highly energy burdened households would drop by 15 percentage points compared to today.

That is the dedicated heat pump delivery rate's equity impact on households that currently heat with natural gas. What about those that heat with delivered fuels?

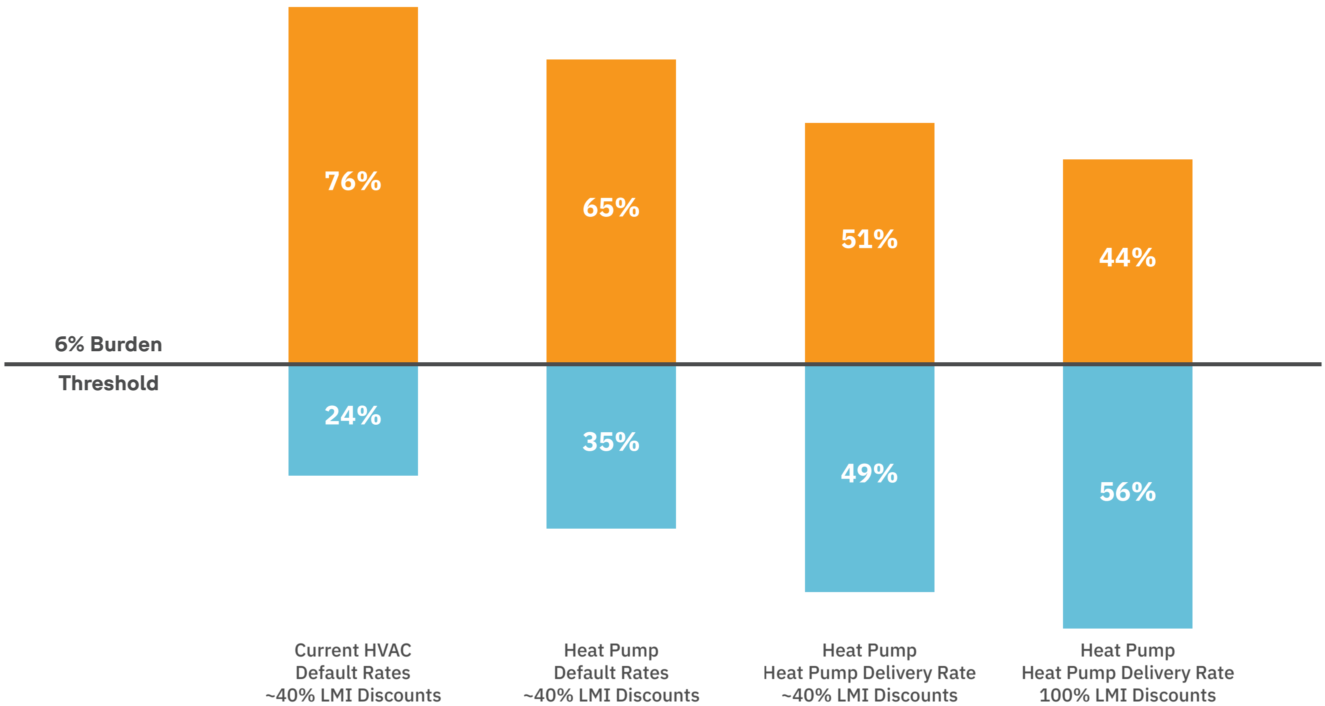


Figure 19: Share of low-income households that heat with oil or propane above the 6% high energy burden threshold

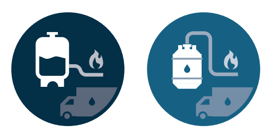


Figure 19 shows the same four scenarios applied to LMI households that heat with **heating oil or propane**, fuels which are nott discounted by utility energy affordability programs:

1. Today **76%** of this cohort is highly energy burdened — well above the **47%** share for the gas-heated LMI population — reflecting the higher cost of oil and propane relative to natural gas.

2. After a heat-pump switch on default rates (and 40% EAP enrollment), **65%** would be highly burdened — a **decrease** of 11 percentage points from today, unlike the increase for gas (because heating load shifts from expensive delivered fuel to electricity and total energy bills can fall even before rate reform).

3. The dedicate delivery heat pump rate (and 40% EAP enrollment) scenario brings the highly burdened share to **51%**

4. The dedicated rate and 100% EAP enrollment scenario drops it to **44%** — down 33 percentage points compared to today.

Finally, here are the results for LMI households with **electric resistance** heating:

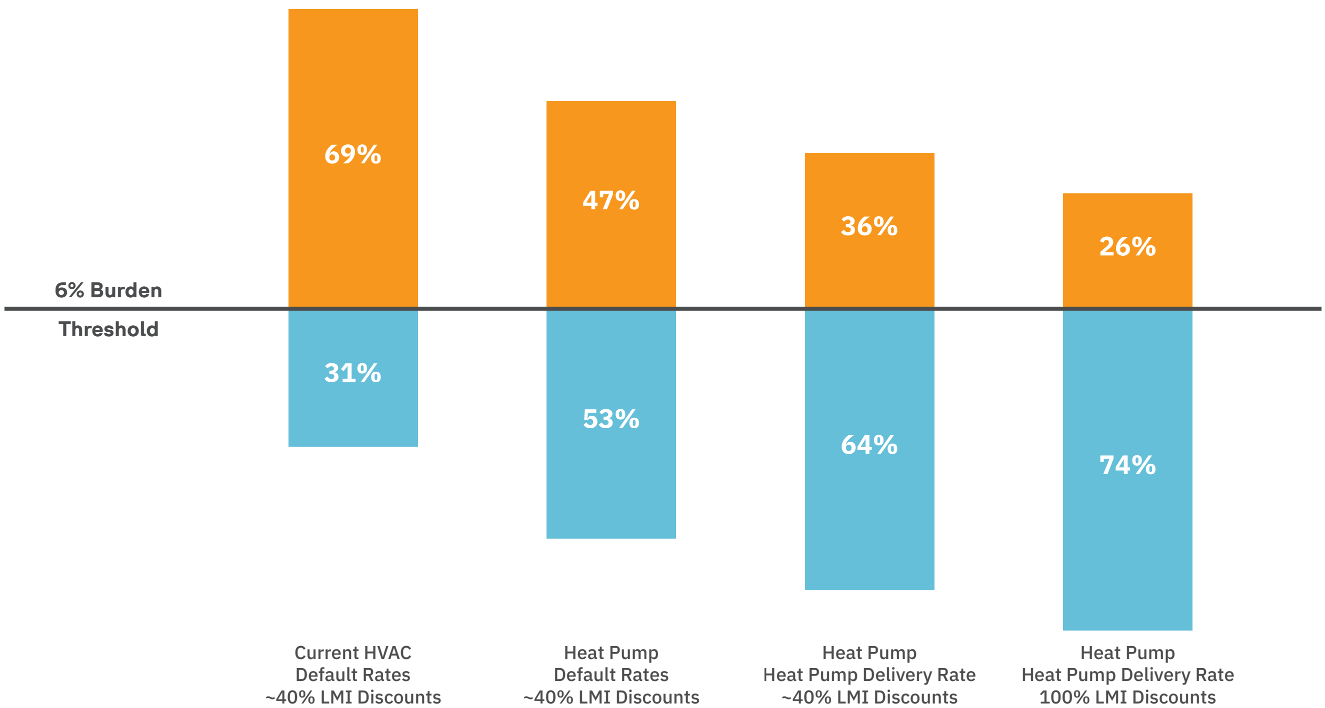


Figure 20: Share of low-income electric-resistance households above the 6% high energy burden threshold

1. Today **69%** of LMI electric resistance households are highly energy burdened — well above the highly burdened share of gas-heated households — because resistance heating is electricity-intensive and these customers are overpaying for that electricity.
2. After a heat pump switch on default rates (with 40% EAP enrollment), the highly burdened share falls to **47%** — a decrease of 21 percentage points, because a heat pump delivers the same heat for far less electricity than resistance equipment.
3. Under the dedicate delivery heat pump rate (and 40% EAP enrollment) scenario, this drops further to **36%**, because they are no longer overcharged for electric delivery.
4. The dedicated rate and 100% EAP enrollment scenario would drop the highly burdened share to **26%** — a decline of 42 percentage points compared to today.

BILL IMPACT OF DEDICATED RATE ON OTHER CUSTOMERS

As we saw earlier, households that heat with natural gas are underpaying for electric delivery by **$131** per year, on average, while those with oil or propane are underpaying by **$75**.

Part of why this happens is that heat pump customers are overpaying for delivery — by **$855** per year, on average — which allows utilities to lower the volumetric delivery rate on everyone.

If all heat pump customers adopted the dedicate delivery rate, this cross-subsidy would be removed. The volumetric delivery rate used by non-heat pump customers would need to rise slightly to maintain the utility's total delivery revenue requirement.[37] How would this affect their bills (Figure 21)?

37 This means the dedicate delivery rate is not revenue neutral for heat pump customers — that would defeat the entire purpose of the rate. But, paired with adjustments to the default rate, it *is* revenue neutral at the level of the residential customer class as a whole, and thus maintains revenue sufficiency for the utilities.

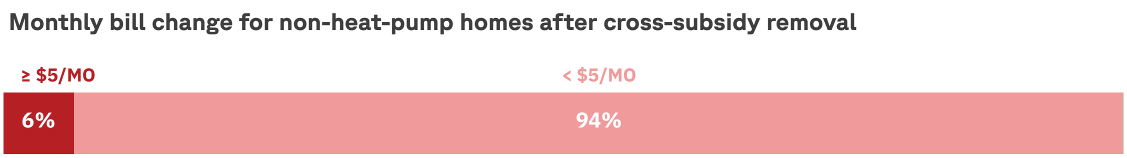


Figure 21: Average monthly bill change — all non-heat-pump homes after cross-subsidy removal (NY, Statewide). Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

By **$2.00 per month**, on average.

In fact, **94%** of non-heat-pump households would see their monthly electric bill rise by less than $5 a month.

In a policy context, this would not be a rate hike; it would be the removal of a cross-subsidy that electric customers that heat with fossil fuels currently receive from heat pump customers, and a step toward better aligning delivery rates with each customer's actual cost of service.

Why so little?

Because heat pump customers only make up 3% of residential customers. The total cross-subsidy they generate, around **$170 million per year**, gets spread across 7.1 million non-heat-pump households.

The result: the benefit each non-heat pump household receives from the cross-subsidy is small — but the cost each heat pump household bears is large, as we saw in Figure 15.

This shows how counterproductive this unintentional public policy of cross-subsidization really is: the state is trying to advance heat pump adoption, but the utilities' default delivery rates are penalizing the customers who electrify their heating — while delivering negligible savings to everyone else.

This asymmetry won't last forever. As heat pump adoption grows, the cross-subsidy will grow with it, and fixing the **fairness problem** will become harder.

Removing the cross-subsidy now, on the other hand, would involve a small increase in the bills of non-heat-pump customers, and this would be a one-time adjustment: going forward, if customers installing heat pumps also enrolled in the dedicate delivery rate, they would never be overcharged in the first place. The bill of other customers would be unaffected.

RATE DESIGN 2: A DEDICATED ELECTRIC HEATING DELIVERY RATE

The dedicated heat pump delivery rate corrects one cross-subsidy — the one heat pump customers pay into. But heat pump customers are not the only New Yorkers overpaying for electric delivery. Electric resistance customers overpay by **$873** per year on average — slightly more per household than heat pump customers — and there are far more of them than there are electric customers with heat pumps.

Electric resistance heating

A class of electric heating equipment — baseboard heaters, electric furnaces, space heaters — that converts electricity directly into heat by running a current through a resistive element

What if we fixed both overpayments at once? One pathway is to calculate electric delivery cost of service for residential heat pump *and* electric resistance customers together, set a combined delivery revenue requirement for this "electric heating" group, and design a single dedicated rate calibrated to collect that revenue.

Every residential electric heating customer in the state would be eligible — heat pump customers and electric resistance customers alike. If this rate were applied to such customers, it would eliminate the statewide cross-subsidy that currently flows from electric-heated to fossil-heated households.

Table 6 shows what the electric heating rate would look like in each utility.

	ConEd	NiMo	NYSEG	CenHud	RG&E	O&R	PSEG-LI
Summer delivery rate (¢/kWh)	15.48	8.67	10.24	14.58	7.07	11.75	10.08
Winter delivery rate (¢/kWh)	4.91	2.46	2.74	4.56	1.93	4.09	3.43
Winter discount	68.3%	71.6%	73.3%	68.8%	72.7%	65.2%	66.0%

Table 6: Proposed electric-heating seasonal rate, per utility. Applies to combined heat pump and electric-resistance customers. Summer rates match the current default rate (when default rate is flat); winter rates are reduced to align heat pump and electric-resistance customers' annual bills with their combined cost-of-service.

The electric heating delivery rate's seasonal design mirrors the one we used for the heat pump-only rate: the summer volumetric rate matches the current default rate — so no electric heating customer pays more in summer than they would under the default rate today — and the winter rate is lowered enough to bring electric heating customers' annual delivery revenue in line with their combined cost of service.

If this rate were applied to all heat pump and electric resistance customers, what would happen to the overpayments and underpayments we saw earlier?

EH seasonal rate eliminates cross-subsidy from electric-heating customers to those who heat with fossil fuels

		All customers on utility's default rates		Electric-heating customers (HP + ER) on EH seasonal rate; fossil-fuel customers on adjusted flat rate			
Heating source	Avg. cost of service	Avg. delivery bill	Avg. cross-subsidy	Change in avg. delivery bill	Avg. delivery bill	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	$1,086 / year	$1,940 / year	$855 / year	−$810 / year	$1,131 / year	$45 / year	4.2%
Electric resistance	$1,072 / year	$1,945 / year	$873 / year	−$886 / year	$1,058 / year	−$14 / year	−1.3%
Natural gas	$1,060 / year	$930 / year	−$131 / year	$112 / year	$1,041 / year	−$19 / year	−1.8%
Delivered fuels	$1,113 / year	$1,038 / year	−$75 / year	$122 / year	$1,160 / year	$47 / year	4.2%
Other	$1,060 / year	$912 / year	−$148 / year	$136 / year	$1,049 / year	−$12 / year	−1.1%
All customers	$1,075 / year	$1,075 / year	$0 / year	$0 / year	$1,075 / year	$0 / year	0.0%

Table 7: Average electric delivery bill, delivery cost of service, and cross-subsidy by subclass, under two sections: 1. all customers under each utility's current default rates and 2. all electric-heating customers (HP + ER) on utility's EH seasonal rate and all other customers on utility's adjusted flat rate. Assumes lump-sum residual allocation (equal residual share for all customers).

By design, the electric heating rate collects annual delivery revenue from heat pump and electric resistance customers equal to their combined cost of service, thereby nearly eliminating overpayments. And because a larger cross-subsidy is being unwound, the underpayments by natural gas, oil, and propane customers shrink further than they did under the heat pump-only rate.

In other words, this rate would fix the fairness problem that affects *all* residential electric heating customers in New York State. What would that mean for their bills?

Would gas-to-heat-pump switchers still benefit?

Widening the rate's eligibility to electric resistance customers barely changes the math for households switching from natural gas to *heat pumps*.

How bills would change for natural gas heated homes after switching to heat pumps

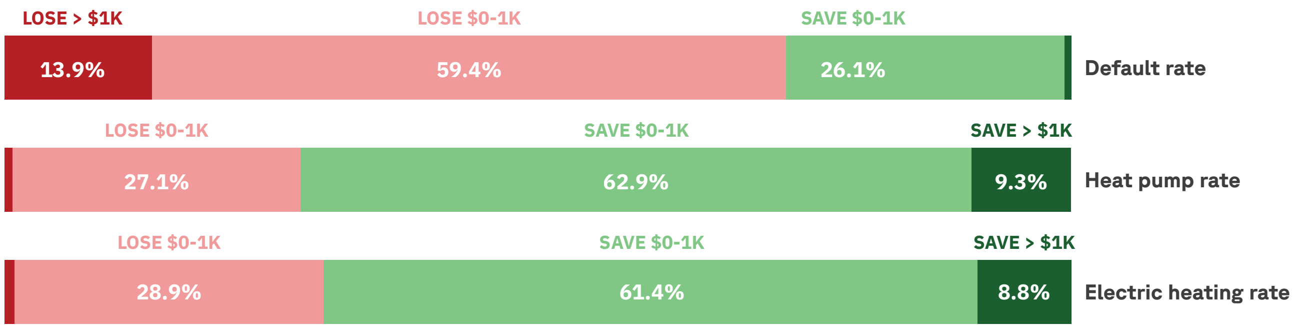


Figure 22: Change in total annual energy bills — natural gas homes switching to a heat pump: default rate vs. electric heating rate (State-wide). Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

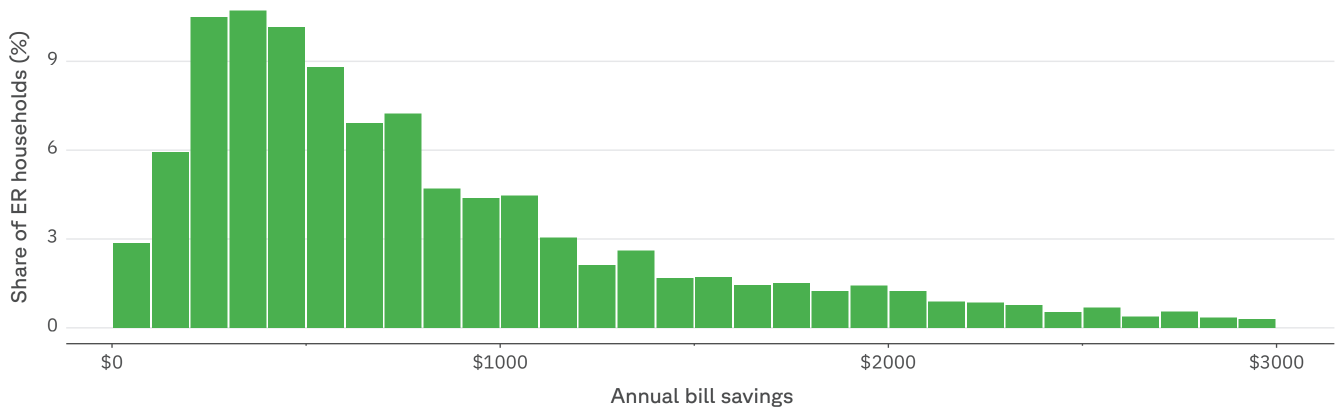
Under default rates, only **27%** of gas-heated households would save by switching to heat pumps. Under the electric heating rate, **70%** would. And the share of gas-heating customers losing more than $1,000 per year when they switch to a heat pump would drop from 14% to just 1%.

In other words, extending eligibility to electric resistance customers does not weaken the economics of switching from gas to heat pumps: the summer rate is unchanged, the winter rate is only slightly higher, and gas-to-heat-pump bill improvements are essentially the same.

What happens to electric resistance customers under the electric heating rate?

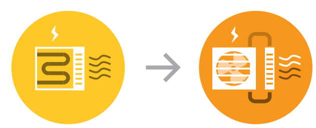
Electric resistance customers that keep their existing equipment but adopt the electric heating rate would see their bills fall — because the rate collects delivery revenue from them in line with their cost of service.

ER homes under the electric heating rate: annual bill savings distribution



All of them would save, averaging **$73.62** per month — roughly **$883** per year.

Does lowering electric resistance bills weaken the case for switching from electric heating to heat pumps?



In theory, yes. If electric resistance customers pay less for electricity, the savings they would get from upgrading to a heat pump shrink. In practice, their savings would still be significant.

How bills would change for electric resistance heated homes after switching to heat pumps

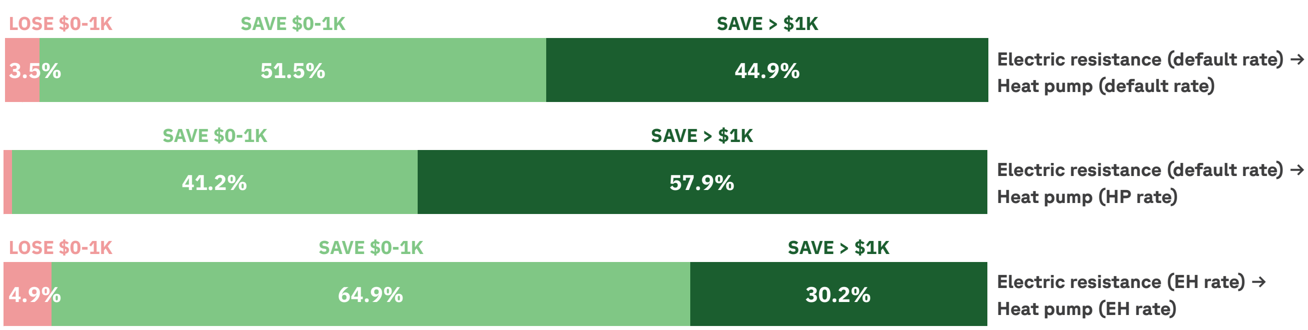


Figure 24: Annual bill change for electric resistance homes switching to a heat pump under three rate regimes (NY, Statewide). Bar 1: default rate before and after. Bar 2: default rate before, seasonal heat pump rate after. Bar 3: electric heating rate before and after. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

As we saw earlier, under today's default rate, **96%** of electric resistance homes would save by upgrading to a heat pump — averaging **$1,309** per year. If this upgrade was paired with opting in to the dedicated heat pump delivery rate, **99%** would save, averaging **$1,764** per year.

However, if those electric resistance customers were already on the electric heating rate before upgrading, rather than on the default rate, **95%** would save after the switch — averaging **$866** per year.

The electric heating rate narrows the operating-cost gap between heat pumps and electric resistance, but the gap remains substantial — approximately a thousand dollars a year, on average.

Bill impact on non-electric-heating customers

The dedicated heat pump delivery rate removes a cross-subsidy of **$170 million** per year from residential heat pump customers to customers that heat with fossil fuels. The electric heating delivery rate removes the overpayment from electric resistance customers as well — another **$571 million** per year — bringing the total cross-subsidy removed to **$741 million** per year. That larger correction would be borne by the customers left on the default rate: households that heat with natural gas, oil, and propane.

How much would that add to their bills?

Monthly bill change for fossil-fuel homes: dedicated heat pump delivery rate vs. electric heating delivery rate

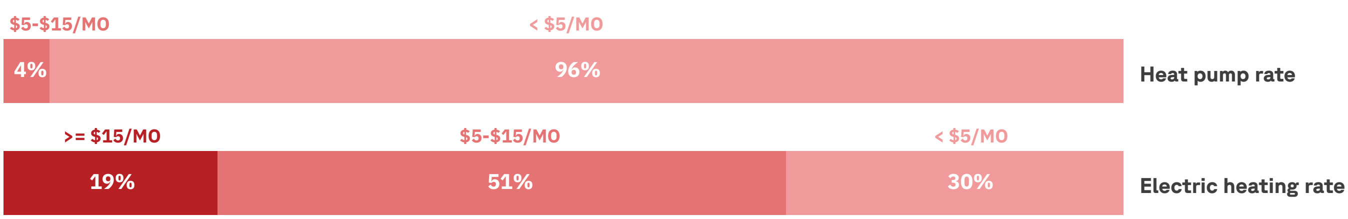


Figure 25: Average monthly bill change — non-electric-heating homes (natural gas, fuel oil, propane, other) under the seasonal heat pump rate vs. the electric heating rate (Statewide). Homes maintain current heating equipment, bill changes reflects the recalibrated default rates only. Assumes ~40% of LMI households are enrolled in utility energy affordability programs.

On average, non-electric-heating households would pay **$9.64** more per month, compared to the **$2.00** per month impact of the heat pump-only rate, reflecting the larger cross-subsidy being unwound. **30%** would see a monthly change of less than $5, and **81%** would see their bills go up by $15 per month or less.

This would not be a rate hike; it represents the removal of a cross-subsidy that gas, oil, and propane customers have been receiving for years from their electric-heating neighbors. Extending the dedicated delivery rate to all electric heating customers would end that cross-subsidy in full, rather than removing just the portion attributable to heat pump customers.

The dedicated heat pump deliver rate we model on p. 70 is cost-based, so it solves the fairness problem: it allocates delivery costs so that heat pump customers now longer overpay.

"But it is not cost-reflective: prices are still flat within each season, sending no signal about *when* electricity is cheap or when usage may trigger an upgrade to the network. Adding time-of-use pricing to the dedicated heat pump rate would help it address the efficiency problem as well..

A time-of-use rate goes further. As the name suggests, the dedicated heat pump delivery rate only touches the *delivery* side of the bill — it lowers the volumetric delivery rate in winter so that heat pump customers, as a group, pay for the poles and wires in line with their cost of service. It does not change *supply* rates at all.

But for time-varying pricing to send useful signals, it needs to reflect *both* sets of costs: the hour-by-hour cost of generating electricity (supply) and the cost of expanding grid capacity (delivery).[38]

For each utility in New York, we've therefore designed TOU rates specifically for heat pump customers that cover both supply and delivery. These rates are both cost-based *and* cost-reflective.[39]

The optimal time-of-use rates for each utility vary in start hour, duration, and price level, as shown in the following charts.

38 A TOU rate that only varied delivery prices would miss the larger source of hourly cost variation — energy costs — and would send incomplete price signals.

39 In other words, the on-peak and off-peak prices for supply and delivery are approximately aligned with the underlying **marginal energy** and **T&D capacity costs**, while the total delivery revenue collected from heat pump customers remains the same as under the dedicated rate — preserving the **cost allocation** that eliminates the **cross-subsidy**.

Cost-reflective rate

A rate with prices that track underlying supply and delivery costs. Cost-reflective rates solve the efficiency problem by giving customers an incentive to shift consumption to hours with lower costs, but they don't guarantee that each group pays their fair share of these costs.

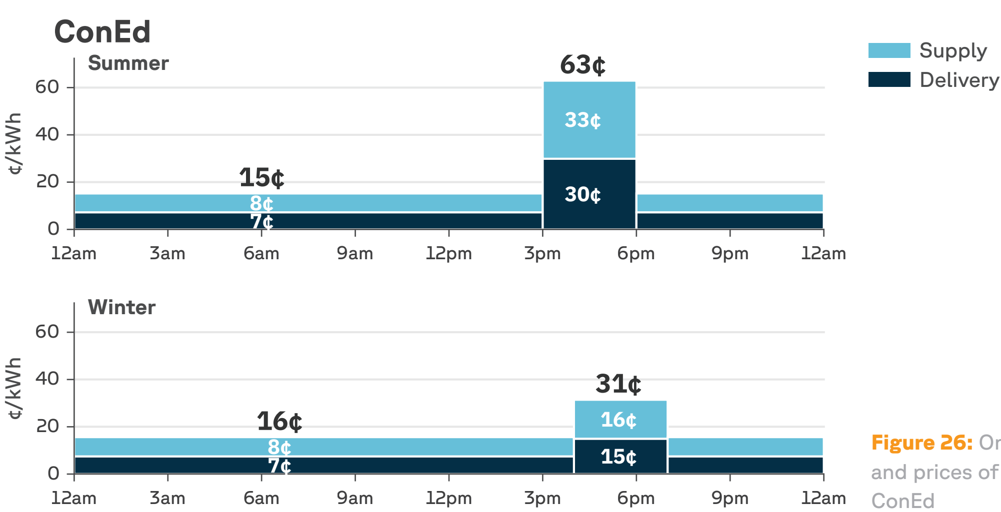


Figure 26: On-peak and off-peak schedule and prices of TOU heat pump rate designed for ConEd

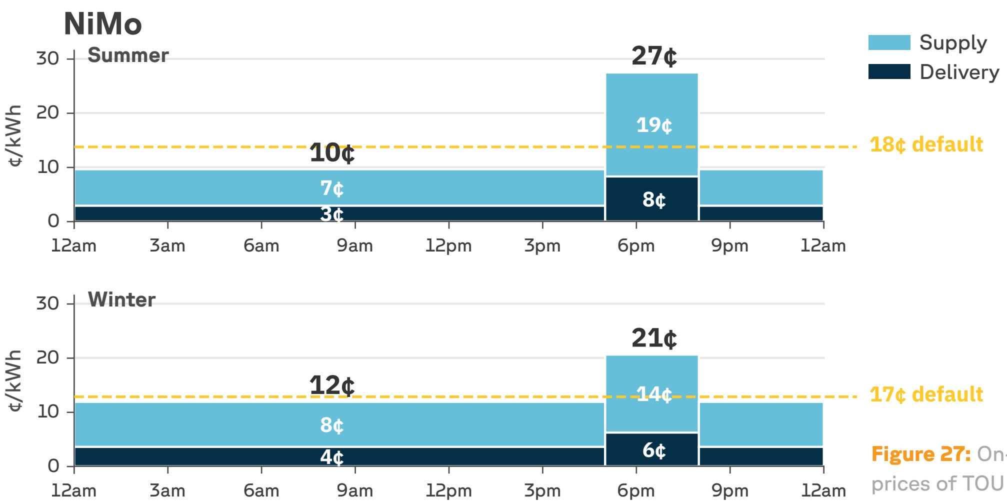


Figure 27: On-peak and off-peak schedule and prices of TOU heat pump rate designed for National Grid

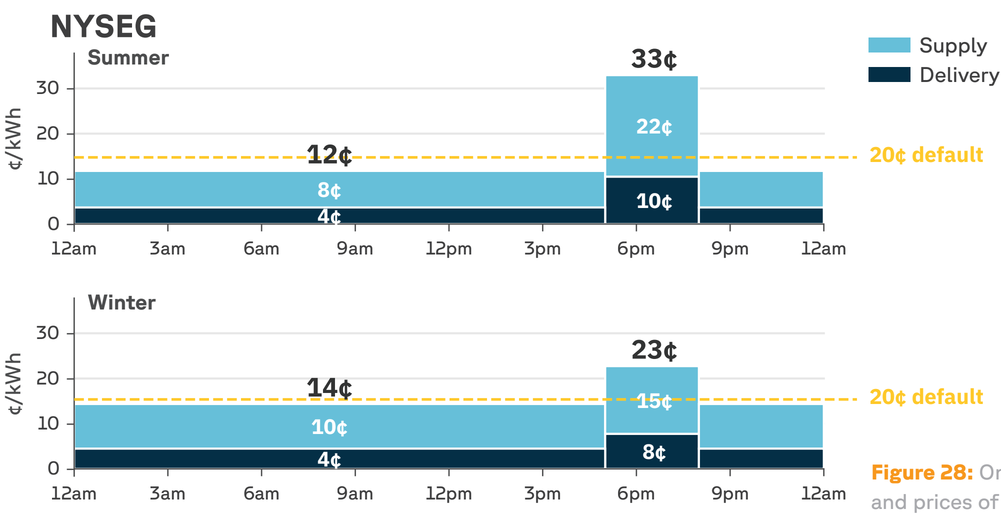


Figure 28: On-peak and off-peak schedule and prices of TOU heat pump rate designed for NYSEG

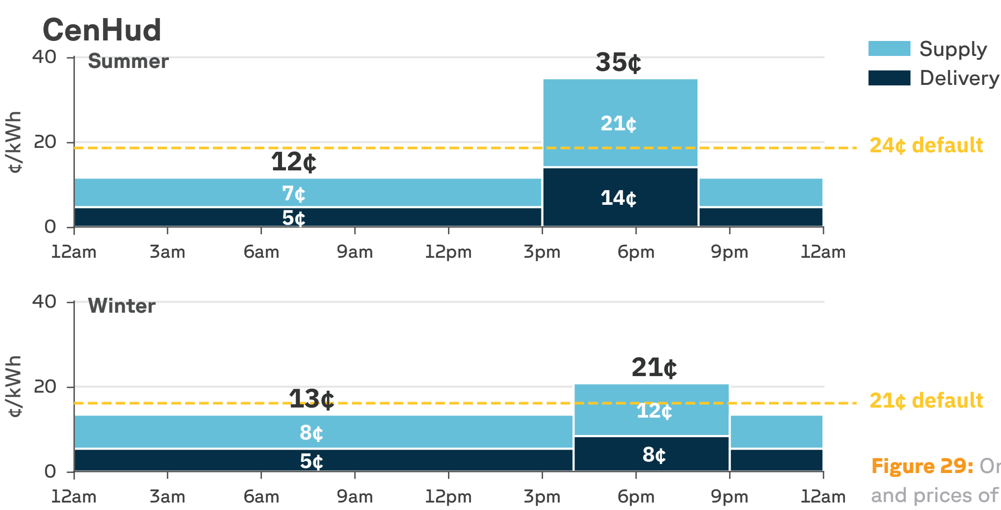


Figure 29: On-peak and off-peak schedule and prices of TOU heat pump rate designed for Central Hudson

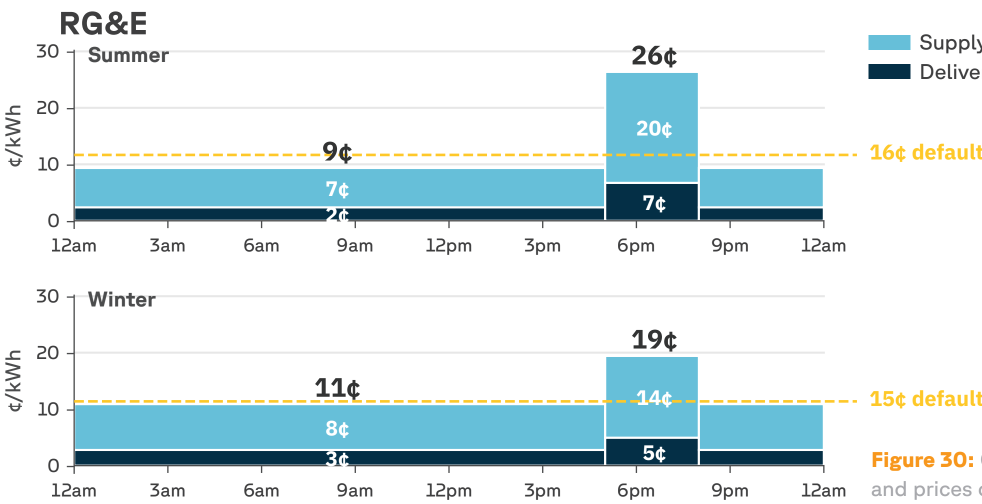


Figure 30: On-peak and off-peak schedule and prices of TOU heat pump rate designed for RG&E

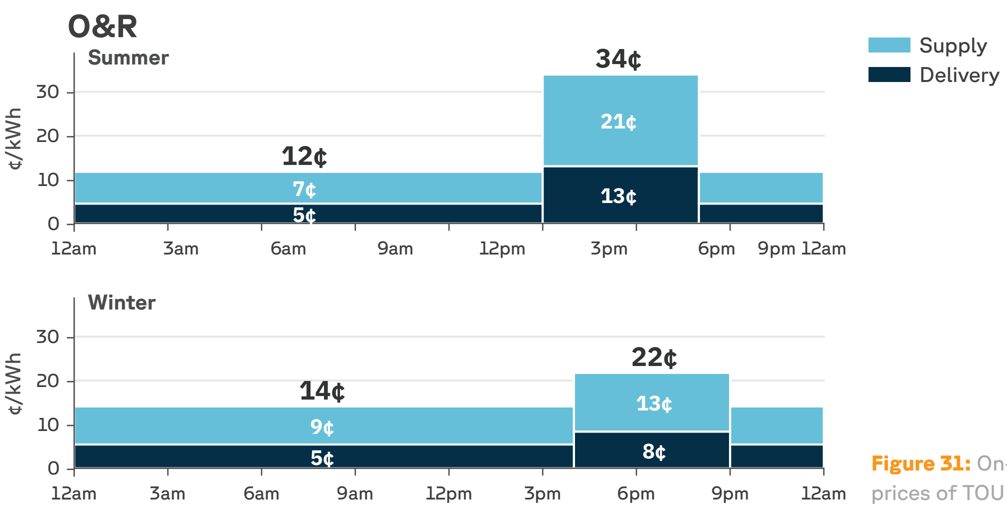


Figure 31: On-peak and off-peak schedule and prices of TOU heat pump rate designed for O&R

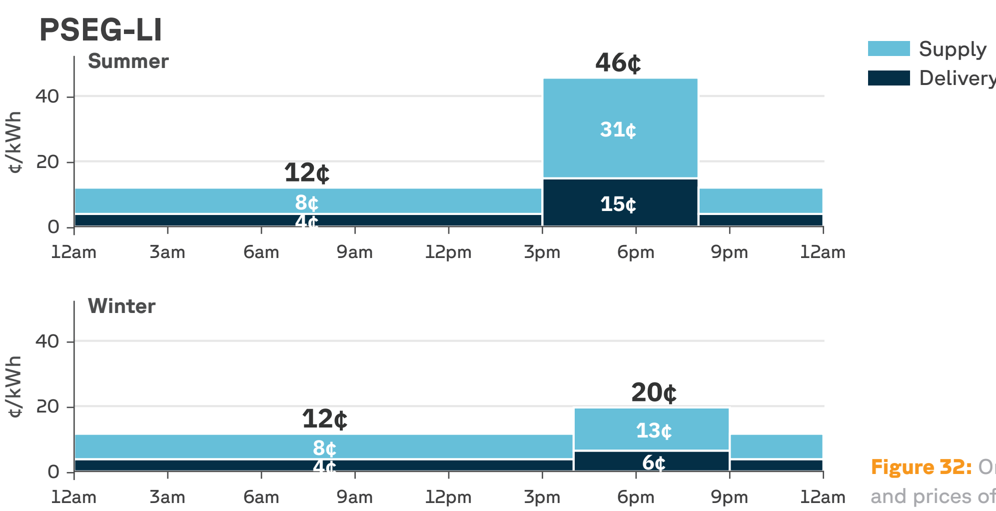


Figure 32: On-peak and off-peak schedule and prices of TOU heat pump rate designed for PSEG-LI

BILL IMPACT OF TIME-OF-USE RATE ON HEAT PUMP CUSTOMERS

If customers installing heat pumps adopted these rates, how much lower would their bills be?

It depends on the extent to which these households shift their electricity use to off-peak periods, which would produce lower bills.

Depending on the utility, we assumed that heat pump customers would shift between 13% and 17% of their on-peak consumption to off-peak periods in summer, and between 6% and 8% in winter.[40]

40 The larger a utility's on-to-off peak differential in a given season, the larger the load shift assumed. We calibrated these assumptions based on the empirical evidence on "technology-enabled" load reductions from the Arcturus 2.0 meta-analysis of time-varying pricing pilots (Faruqui et al. 2017).

Compared to default rates, a TOU heat pump rate would dramatically improve gas-to-heat-pump bill outcomes (Figure 33).

How bills would change for natural gas heated homes after switching to heat pumps

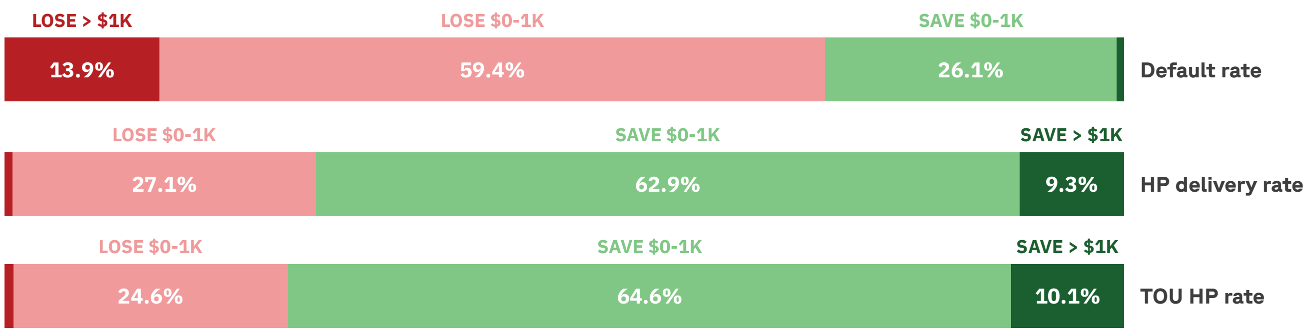


Figure 33: Change in total annual energy bills — natural gas homes switching to a heat pump: default rates vs. dedicated heat pump delivery rate vs. time-of-use heat pump rate (Statewide). Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

Under default rates, only **27%** of gas-heated households would save by switching to heat pumps. Under the TOU heat pump rate, **75%** would. And the share of households losing over $1,000 per year would drop from 14% to just 1%.

Compared to the less cost-reflective but still cost-based dedicated heat pump delivery rate, however, the TOU rate only does a little bit better: **75%** of gas-heated households would save under the TOU heat pump rate, up from **72%** under the dedicated heat pump delivery rate — and those that save would save an extra **$31** a year, on average.

Why aren't the savings more substantial?

LOAD SHIFT IMPACT OF TIME-OF-USE HEAT PUMP RATE ON HEAT PUMP CUSTOMERS

Because there's not that much on-peak load to shift to off-peak periods, and only a fraction of the on-peak load would actually be shifted. Figure 34, which shows a ConEd customer's electricity use and bill before and after shifting under the modeled TOU heat pump rate for ConEd, illustrates this point.

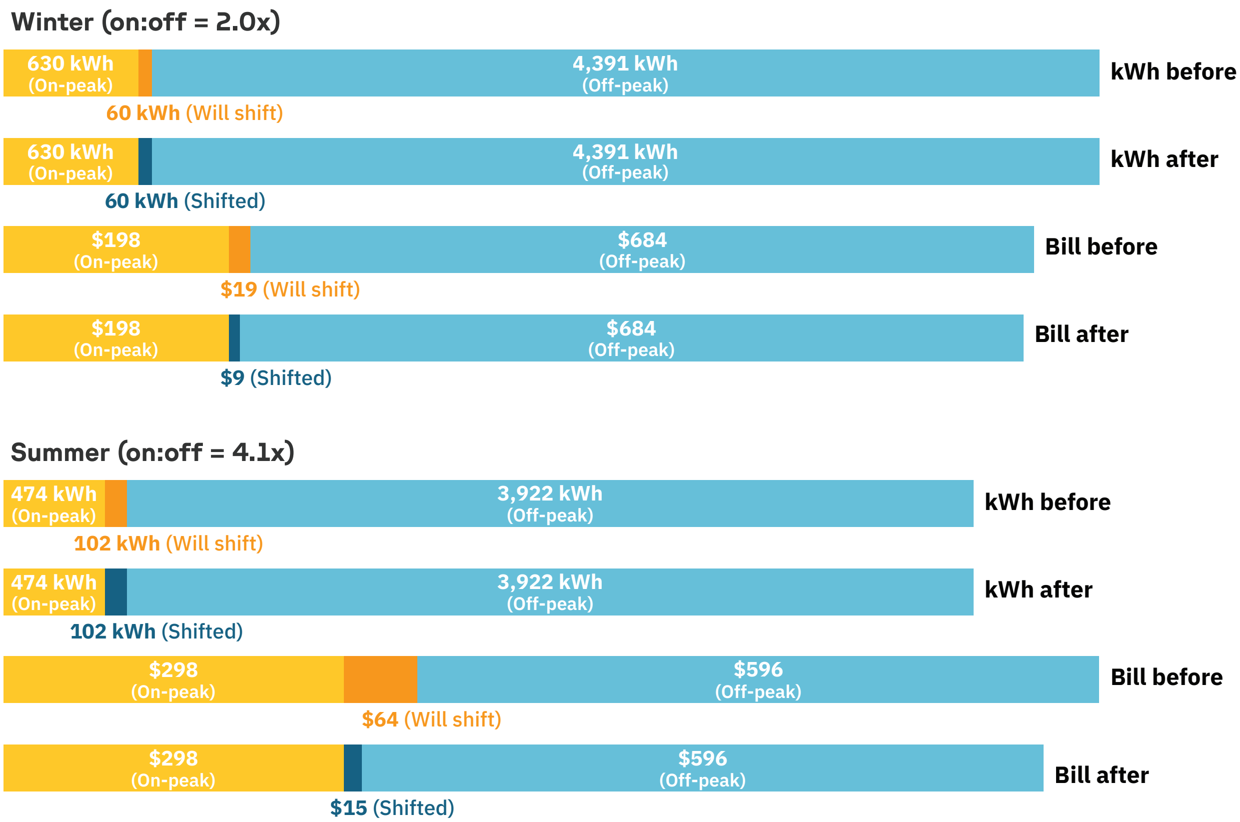


Figure 34: Before and after demand-flex: seasonal kWh and bill for a representative heat pump building

In winter, their on-peak electrical consumption represents 14% of their total consumption, and the 2.0x difference between ConEd's on-peak and off-peak prices (31¢ and 16¢ per kWh, respectively) would lead them to shift[41] **9%** of this load to off-peak, resulting in a **$10** lower bill at the end of the season.

In summer, their on-peak electrical consumption represents 13% of their total consumption, and the 4.1x difference between the modeled on-peak and off-peak prices (63¢ and 15¢ per kWh, respectively) would lead them to shift **18%** of this load to off-peak, resulting in a **$49** lower bill at the end of the season.

41 We assumed that the bigger the gap between a utility's on-peak and off-peak prices, the more on-peak load customers shift to off-peak. We calibrated this demand shifting for each utility and season so it reproduces the peak reductions observed across 62 time-varying pricing pilots in the Arcturus 2.0 meta-analysis (Faruqui et al. 2017); see p. 129 for the full methodology.

To be clear: the TOU heat pump rate we modeled would eliminate the **cross-subsidy** as well as the dedicate heat pump delivery rate, and it would promote **economic efficiency**, which would save heat pump customers slightly more money. From that perspective, it is superior to the dedicated delivery rate we modeled earlier, in p. 30.

Nearly all of the improvement in bill impact compared to the **default rate**, however, comes from the fact that the TOU rate is **cost-based**, not from the fact that it is **cost-reflective**: in other words, nearly all of the improvement comes from the fact that the rate is designed to collect less money from heat pump customers, just like the dedicated delivery rate, and *not* from the inclusion of two price levels (that reflect the underlying **marginal costs** of energy and infrastructure).

WHY THE GRID CAN HANDLE THE ADDITIONAL LOAD

Stepping back from the rate designs themselves, let's revisit why the cross-subsidy exists in the first place. Under today's **flat volumetric delivery rates**, every kWh a heat pump customer consumes is priced as if it were causing new **delivery costs** — as if it were triggering feeder upgrades, substation expansions, or new transmission lines. That assumption only holds in summer, when the grid is stretched to meet air-conditioning-driven peaks. Most of a heat pump customer's additional consumption, however, happens in winter, when the grid has ample unused capacity. Using volumetric rates to charge every kWh at the same price level is what produces the overcharge.[42]

So how much unused winter capacity does New York's grid actually have?

Over the past ten years, New York's grid-wide **winter peak** has averaged only **77%** of the summer peak (Figure 35).

42 The overcharge occurs both because flat volumetric rates fail to reflect **marginal** delivery costs, which only occur in summer, and because recovering **embedded** delivery costs volumetrically will tend to overcharge customers who consume more electricity than average. This section focuses on the first issue.

Peak demand

The maximum current served by a particular electrical infrastructure component during a specified time period, usually a season or year.

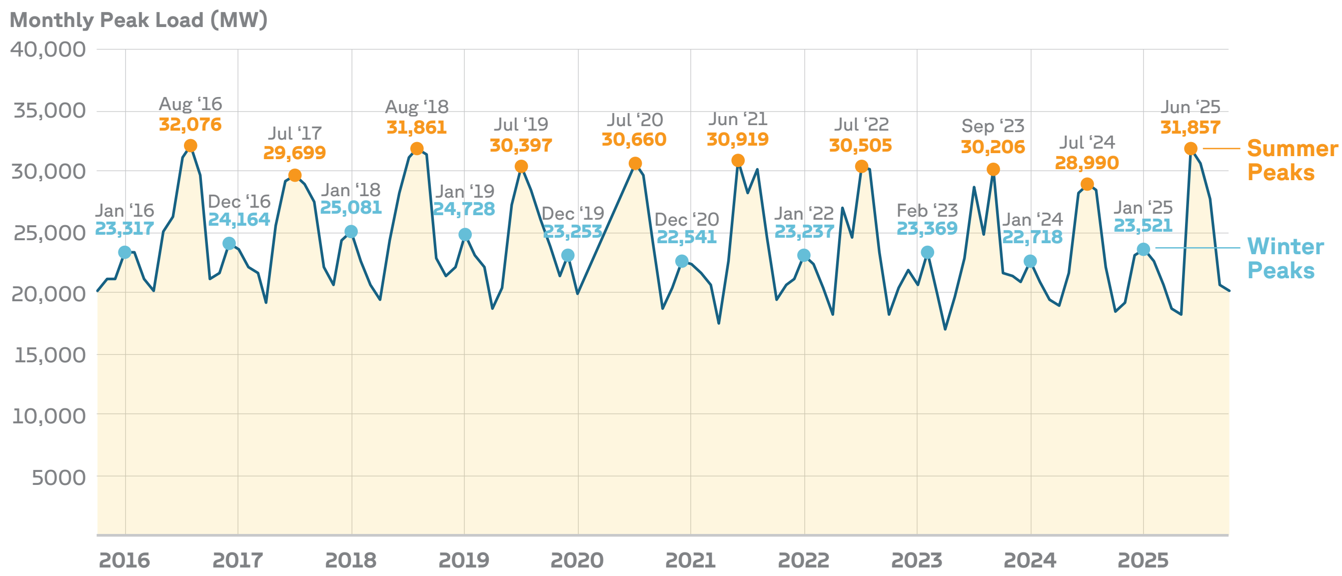


Figure 35: NYISO monthly peak load, 2016–2025. Summer peaks consistently exceed winter peaks by 25–35%. Source: NYISO.

In other words, at the level of **generation** and **transmission**, around a quarter of the grid's capacity goes unused during the winter.

And since the grid is already sized to handle these summer peaks, there's significant "headroom" for winter peaks to grow up to their level, using existing infrastructure.

But what about at the **distribution** level of the grid?

A recent study by Synapse Energy Economics analyzed the capacity of New York's distribution grid to accommodate building electrification.

While the picture varies by utility, the distribution grid as a whole appears to have even more winter headroom than the bulk power grid:

Utility	Distribution winter peak (MW)	Total estimated winter headroom (MW)	Winter headroom (% of total capacity)
National Grid	4,276	4,477	51%
Central Hudson	796	279	26%
NYSEG and RGE	3,786	3,235	46%
ConEd	4,691	1,346	22%
Orange & Rockland	1,123	1,071	49%
Total	**14,673**	**10,408**	**42%**

Table 8: Distribution grid winter headroom by utility, adapted from p. 4 of (Takahashi et al. 2024).

For instance, in Central Hudson, **26%** of the electric distribution grid's winter capacity is currently unused. In National Grid, the figure is **51%**. The study concludes: "Existing distribution grids could support residential heat pumps reaching roughly 29 percent to 47 percent of the entire heating fuel stock… with the statewide average of 39 percent."[43]

By comparison, only 2.7% of households in New York State currently have heat pumps. And 9.0% are heated with electric resistance — any of these customers that switch to heat pumps would reduce their winter loads, creating additional winter headroom.

Simply put: at present, New York's grid has significant spare winter capacity to accommodate heat pumps. And this is the main reason why their delivery cost of service is only 2% higher than that of electric customers that heat with natural gas.

But this is a snapshot of today. As heat pump adoption grows, winter loads will rise, winter headroom will erode, and the cost of serving heat pump customers will eventually start rising — meaning any rate calibrated to today's cost of service will eventually need to be recalibrated to tomorrow's.

43 See p. 4 of Synapse Energy Economics' distribution headroom report (Takahashi et al. 2024).

HOW SHOULD THE DEDICATED HEAT PUMP DELIVERY RATE EVOLVE AS THE WINTER PEAK GROWS?

The heat pump rates modeled above are designed to be a near- to medium-term solution: they would need to be gradually adjusted over time, and eventually replaced as the grid becomes fully winter-peaking.

The rates we have designed for each utility reflect today's reality: in the summer, some customers installing heat pumps are triggering modest grid capacity upgrades, in cases where they gain more cooling than before.

In the winter, these customers are significantly increasing their electricity use — if they previously heated with fossil fuels. Since the grid has spare **capacity** during these winter months, these new loads are not triggering grid capacity upgrades — though heat pump customers are being charged as if they were. The heat pump rate we modeled corrects this in its **cost allocation**, by lowering the **volumetric** delivery rate for these customers.

Capacity (infrastructure)

The maximum electric current a piece of transmission or distribution equipment — a line, transformer, or substation — can carry safely without damaging the equipment. When demand approaches an asset's capacity, the utility must either upgrade it, or build new infrastructure to handle the load.

While the grid has spare capacity in winter at present, this will not always be the case. Each customer installing a heat pump nudges up the **winter peak** of their feeder, substation, local transmission lines, bulk transmission line, and statewide generators by a tiny amount. Over time, these increases will add up, and eventually drive one or more of these components to become constrained in winter (if the summer peak doesn't rise as well).

As this begins to happen across the state, heat pump adoption could become the main driver of grid capacity investment, the **cost of service** of heat pump customers will gradually increase, and the rates we modeled in this report would need to be adjusted upwards to reflect that.

So how quickly will New York State's grid become winter-peaking?

It will not happen all at once, or at the same time for all utilities, and it will depend on the pace of heat pump adoption and other factors.[44]

NYISO has the most recent and advanced forecast of New York State's heat pump adoption available, and it predicts that the adoption rate is about to pick up (Figure 36).[45]

44 And on the cold-weather performance of the equipment being installed. Widespread deployment of ground-source heat pumps, which maintain high COPs even at low temperatures, would significantly delay the transition to winter-peaking.

45 See NYISO's 2025 Building Electrification Forecast (NYISO 2025a).

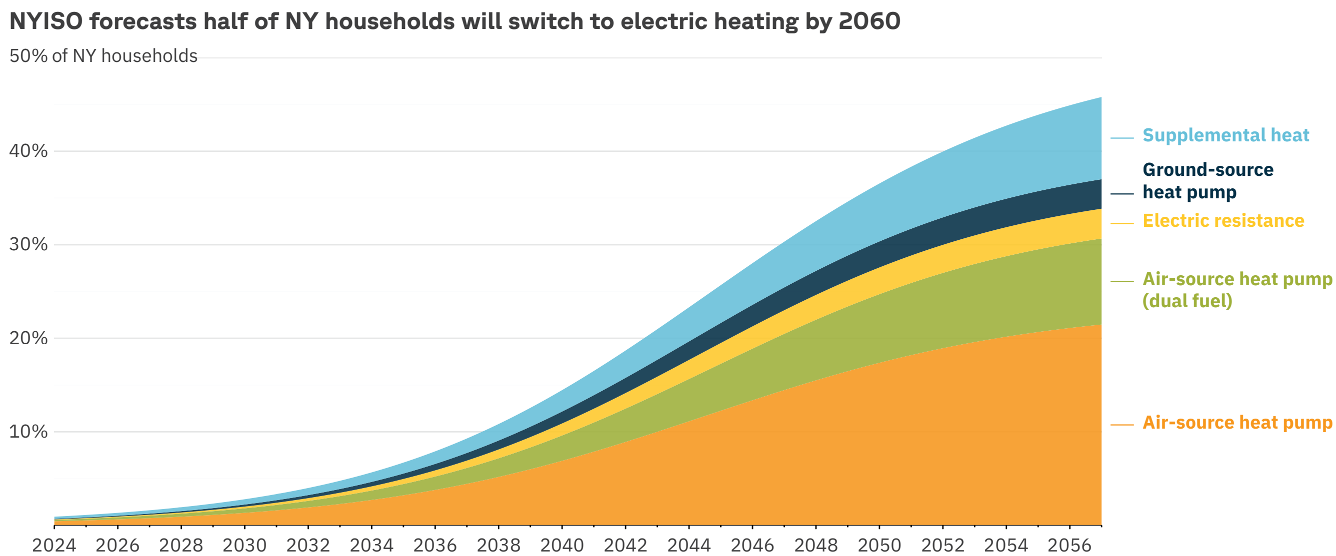


Figure 36: Number of residential households converted to electric heating by technology. Adapted from p. 14 of the NYISO 2025 Building Electrification Forecast.

NYISO's adoption forecast assumes that around half of New York residential buildings will electrify their heating by 2060, along with a similar share of commercial buildings.[46]

In the short-term, heat pump adoption will only trigger generation capacity costs to the extent that it drives up the **summer peak**, the maximum annual demand that determines how much generation capacity the system needs.[47]

46 This is far below the level of adoption needed to comply with the State's climate targets. According to the Integration Analysis of the NY State Scoping Plan (E3 2022), 97% of all residential buildings and 99% of all commercial buildings in the state will need to install heat pumps by 2050 to meet CLCPA targets.

47 Specifically, it would create **generation capacity** costs once system-wide summer-peak growth sufficiently erodes NYISO's current reserve margin.

Generation capacity costs are supply costs

None of the rates modeled in this report reduce the *supply* revenue collected from heat pump and electric resistance customers. Therefore, the changes to supply costs resulting from heat pump adoption discussed in this section have no bearing on the rates we model in this report, and are included for completeness.

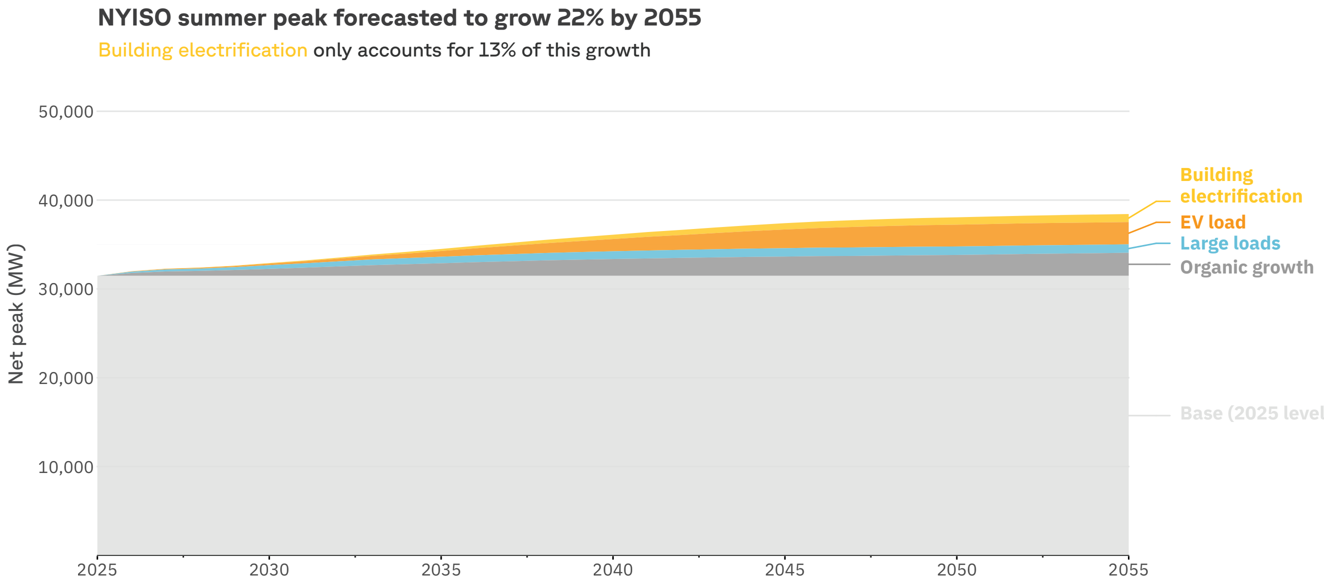


Figure 37: NYISO coincident summer net peak, 2025-2055, decomposed into growth components. Note: each peak growth drives (BE, EVs, large loads, organic growth) is scaled down proportionately by peak reduction sources (EE, DG, storage). Source: NYISO Gold Book 2025.

While the system-wide summer peak is expected to grow steadily over the next three decades (Figure 37), most of that growth will come from EVs, large loads, and "organic demand" — economic growth and warmer summers. Building electrification accounts for a tiny slice of this growth — and of any generation capacity costs that it triggers.[48]

Heat pump adoption will have a much bigger impact on the *winter peak*, however.

The winter peak is currently only **77%** of the summer peak in NYISO's 2025 baseline forecast, but is expected to grow faster and eventually overtake it (Figure 38).

48 NYISO's baseline forecast does not split out heat pump adoption from the broader category of building electrification, though we know that cooling and heating loads dwarf hot water heating, stoves, and other electrified end-uses.

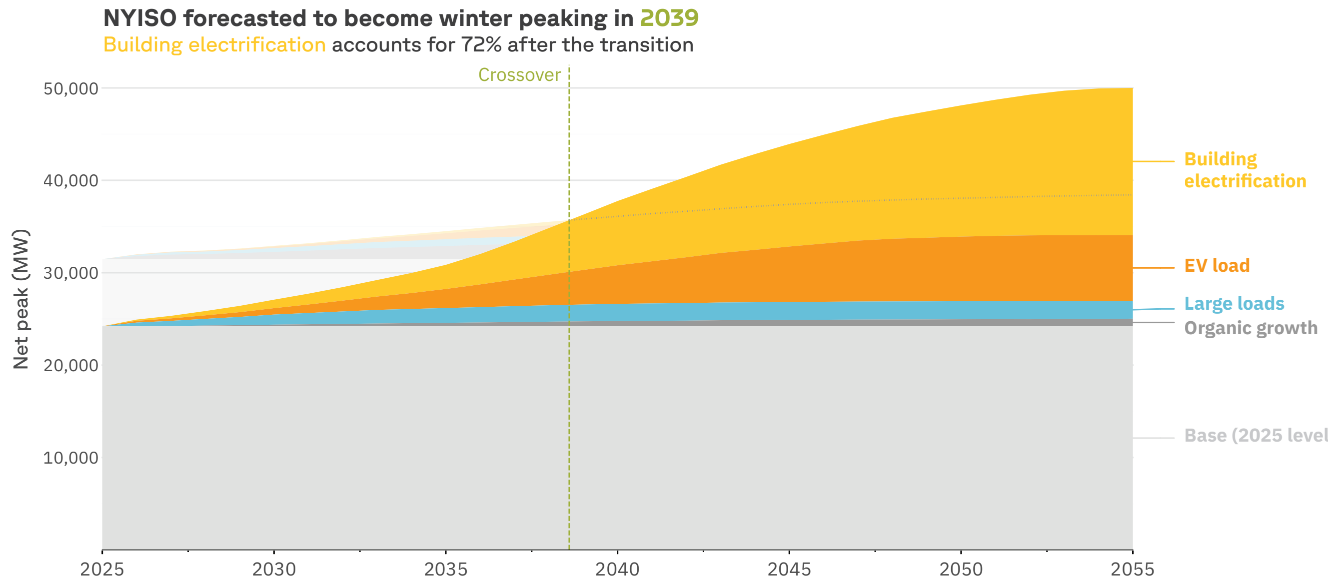


Figure 38: NYISO summer (behind, translucent) and winter (in front, solid) coincident net peak, decomposed into growth components. Note: each peak growth driver (BE, EVs, large loads, organic growth) is scaled down proportionately by peak reduction sources (EE, DG, storage). A fine gray dotted line traces summer total from the season crossover onward. Source: NYISO Gold Book 2025.

In NYISO's baseline scenario, the winter peak overtakes the summer peak for the first time around **2039**, though this crossover is delayed to **2041** in their "lower demand" scenario.

After that point, building electrification becomes the dominant driver of winter peak growth, and is therefore responsible for the majority of new generation capacity costs. [49]

There isn't a single moment that New York's grid becomes winter-peaking, however, which is why the cost-of-service of heat pump customers will change gradually over time.

Impact of heat pumps on delivery costs

The NYISO-wide peak tells us when heat pump adoption may start driving **generation capacity costs**, which are supply costs, but not **transmission and distribution capacity costs** — the delivery costs that heat pump customers are currently overpaying for, and which our heat pump rates address.[50]

The impact of heat pump adoption on **bulk transmission capacity costs** will occur at different times throughout the state.

In transmission-constrained zones like New York City and Long Island, where many multifamily buildings lack full

49 In practice, these generation capacity costs wouldn't wait until after the crossover. Because grid planners build ahead, NYISO's capacity procurement to meet these anticipated winter peaks would begin years before winter formally overtakes summer. Customers could start paying for winter-driven capacity costs as early as the mid-2030s, even while the system is still nominally summer-peaking.

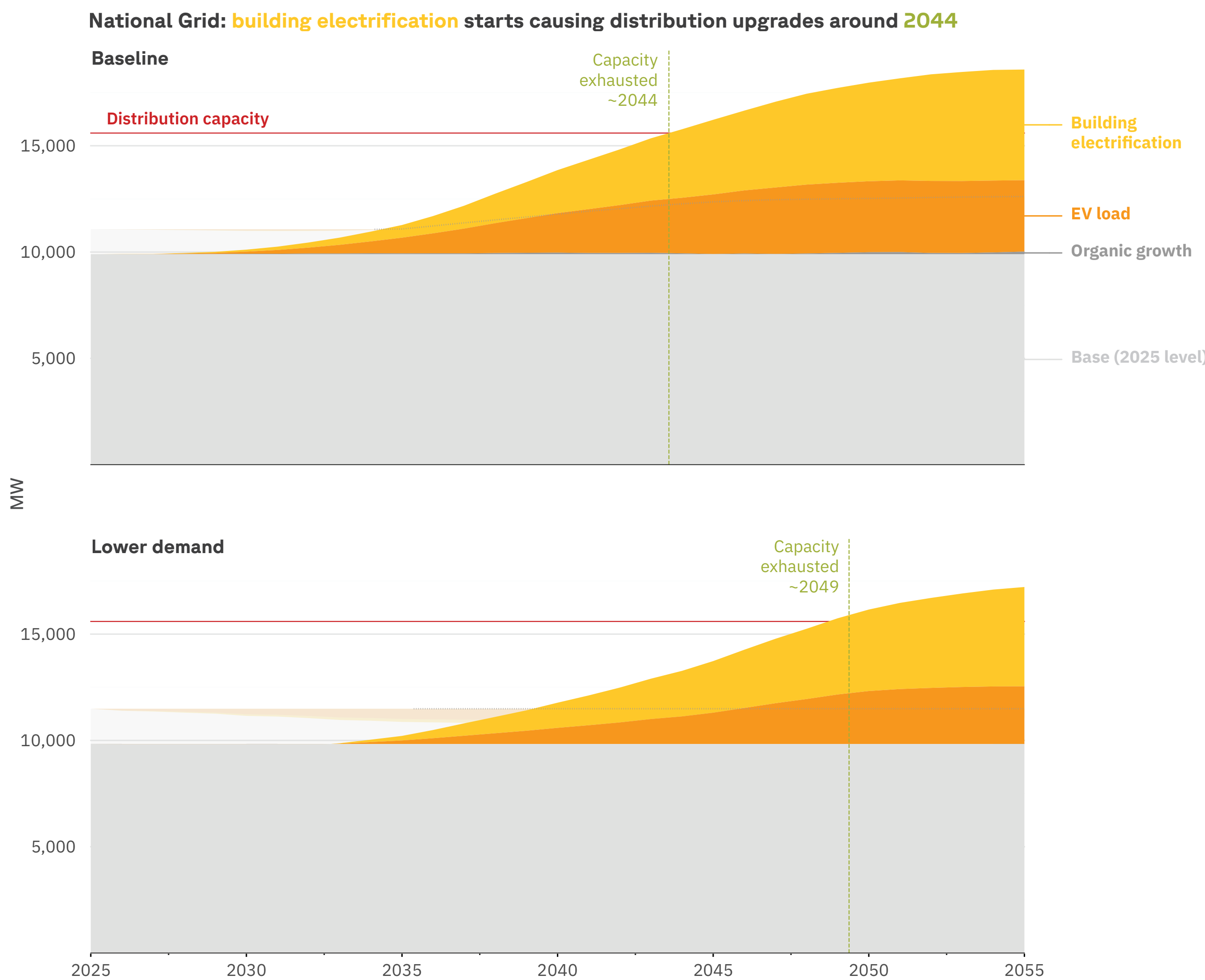
50 Technically, a small slice of transmission costs are paid for by supply rates in NYS, not delivery rates, via the **NYPA Transmission Adjustment Charge** and the **Transco Facilities Charge**. See p. 67 for more details.

cooling, heat pump adoption is likely already contributing to bulk transmission capacity costs (in summer).[51] Upstate, heat pump adoption may not drive the need for bulk transmission upgrades until well after the system as a whole becomes winter-peaking.

51 Albeit modestly, given the slow pace of heat pump adoption in NYC.

Finally, heat pump adoption will start to drive significant **distribution capacity costs** only as feeders and substations start becoming constrained in winter, which will happen gradually, and at different times throughout the state. On the whole, this will likely occur after the system as a whole becomes winter-peaking, due to existing headroom on the distribution grid.

Figure 39: National Grid summer (behind, translucent) and winter (in front, solid) coincident peak decomposed into growth components, excluding large loads. Top: baseline forecast. Bottom: lower demand forecast. Source: NYISO Gold Book 2025.



For instance, in National Grid's upstate territory, the utility-wide winter peak overtakes the summer peak around **2034** (in the baseline scenario). But because National Grid's feeders peak in summer well below their normal capacity, the utility has significant headroom on the distribution grid, and the winter peak can keep growing until approximately **2044** before this headroom is exhausted, and heat pump adoption starts driving significant distribution capacity costs. (In NYISO's "lower demand" scenario, National Grid's distribution headroom isn't exhausted until **2049**.)

For the other utilities, distribution capacity costs would start to increase between 2038 and 2044, depending on the utility and the forecast scenario.[52]

This is our estimate of when winter heat pump use would *start* to constrain feeders and substations.[53] This means the *distribution* component of most utilities' heat pump rates could be left untouched for the next twelve to eighteen years (depending on the utility), and would be gradually adjusted upwards after that, in line with heat pump adoption.

The heat pump rate modeled in this report is a short- to medium-term fix. It corrects today's significant cross-subsidy, where heat pump customers overpay for delivery, in part because the system has spare winter capacity.[54]

But as heat pump adoption starts to exhaust transmission and distribution headroom across the state, heat pump customers will increasingly be the ones driving grid investment — and keeping rates fair will mean reflecting that cost. At the distribution level, these adjustments wouldn't need to begin until the early 2040s, according to NYISO's baseline forecast.

52 For each utility's forecast, see p. 97.

53 Based on utility-level NYISO forecasts (NYISO. 2025b) and and the Synapse Energy Economics distribution headroom assessment (Takahashi et al. 2024). For full methodology, see p. 132

54 But also because the fixed costs of previously built transmission and distribution infrastructure, also known as **embedded delivery costs**, are largely recovered through volumetric rates. See p. 61 for a full explanation.

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Appendix 1: A primer on utility costs, bills, and rates

The Background section (p. 61) near the start of this report introduced utility costs, bills, cost of service, and rates, and previewed why volumetric delivery pricing strains heat pump economics. What follows is a step-by-step deep dive through the same topics — costs and cost of service, then bills and rates — to fully clarify these concepts, and their relationship to both the fairness problem (p. 70) and the efficiency problem (p. 71).

COSTS

Companies build power plants, transmission lines, and distribution lines to produce and deliver electricity to customers. They incur capital costs while doing so, and ultimately need to recoup these costs from customers — plus a profit margin.

In addition to the costs they incur when building this infrastructure, these companies also incur operating costs to operate and maintain their infrastructure, and run their business.

Examples of these capital and operating costs are shown in the table below.

Capital costs

The expenses a power sector companies incur to generate, transmit, and distribute electricity, including capital costs and operating costs.

Operating costs

The ongoing expenses of running and maintaining the electric grid day-to-day. Operating costs recovered from customers in the same year they are incurred.

	Capital Costs	Operating Costs
Generation	**Capacity costs**: Power plants, turbines, solar arrays, battery storage	**Fixed**: Staff, inspections, insurance **Variable (with usage)**: Fuel, water, consumables
Transmission	**Capacity costs**: High-voltage lines, bulk substations, switching stations	**Fixed**: Infrastructure maintenance, vegetation management, property taxes, admin
Distribution	**Capacity costs**: Feeders, transformers, secondary lines **Connection costs**: Meters, service drops	**Fixed**: Infrastructure maintenance, vegetation management, storm restoration, property taxes, admin **Variable (with customers)**: Billing, customer service, meter reading

The operating costs of traditional fossil-fueled power plants go by a special name: **energy costs**, or how much it costs each power plant to generate an additional kWh of electricity at any given moment. This is largely the cost of the fuel they burn to produce it, and a few other consumables.[55]

In fact, these **energy costs** make up the majority of supply costs — the total capital and operating expenses associated with **generation**.

On the other hand, delivery costs — the capital and operating expenses associated with **transmission** and **distribution** — are mostly made up of capital expenses used to build network infrastructure.

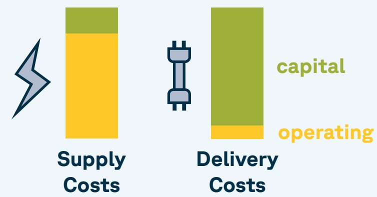
Ultimately, power sector companies incur these capital and operating costs in order to serve customers, be they tiny studio apartments or massive data centers. So customers ultimately recoup these costs through their electric bills.

But how much should each customer be charged? What is each customer's "fair share" of all of these costs?

Capital costs

The capital cost of an infrastructure project that increases the grid's capacity. Capacity costs are a kind of delivery cost, and they exist at every level of the grid: generation capacity costs (power plants), transmission capacity costs (high-voltage lines and bulk substations), and distribution capacity costs (feeders, transformers, secondary lines).

55 Renewables like wind, solar, batteries, hydro, and geothermal have near-zero operating / energy costs, while nuclear has very low energy costs.



Most supply costs are operating (energy costs). Most delivery costs are capital (T&D infrastructure).

Who owns the grid, and how do they get paid?

Formerly, all three kinds of infrastructure were owned and operated in New York by electrical utilities. Utilities incurred these supply and delivery costs themselves, and recouped them by charging customers through their electric bills.

Today, that vertical integration has been unwound, but customers still receive a single consolidated bill from their distribution utility. Here is how the costs of each part of the grid now reach that bill:

- **Distribution** is still owned by the customer's local utility, which recoups its own distribution delivery costs directly through the **delivery** part of the bill.
- **Transmission** is now owned by **transmission owners** — usually the same investor-owned utilities wearing a separate, federally regulated hat (Con Edison, National Grid, etc.), along with the New York Power Authority and a handful of independent developers. The utility collects transmission delivery costs on the transmission owners' behalf, also through the **delivery** part of the bill.
- **Generation** is now owned by **power producers** — independent companies that build power plants and sell electricity into the wholesale markets run by the New York Independent System Operator (NYISO). A **retailer** — either the customer's distribution utility, or a third-party Energy Service Company ("ESCO") — buys wholesale energy and capacity from NYISO on the customer's behalf, and recoups those supply costs through the **supply** side of the customer bill.

COST CAUSATION

The standard answer is that customers should be allocated the costs that they *cause* (and then charged for them through their bills). The jargon is that their **cost of service** should be determined by the **cost-causation principle**.

To see how this might work, let's follow a single customer through their lifecycle, and see which costs they cause at each stage.

> **Cost of service**
>
> *The costs associated with generating and delivering electricity to a particular customer or customer class. A customer's **delivery** cost-of-service is their fair share of delivery costs; **supply** cost-of-service is their share of supply costs.*

Let's say a family moves into a newly built home. When they first sign up for electricity service, the utility installs a meter and connects their home to the local power line with a service line.	*causes...* Distribution Capital Costs **Connection Costs**: meters, service drops
The utility starts reading their meter and sending them bills. The family is causing new operating costs — specifically, variable customer-related operating costs.	*causes...* Distribution Operating Costs **Variable (with customers)**: billing, meter reading
As the family uses electricity, hour by hour, generators have to burn a little more fuel to keep up. The family is causing new operating costs — specifically, variable usage-related operating costs.	*causes...* Generation Operating Costs **Variable (with usage)**: fuel, etc.
During the summer, they run their air conditioner during a heat wave, at the same time as many other customers. Most generators are running at full tilt — including many that sit idle for much of the year. By consuming electricity during these **peak hours**, the family is contributing to the need to pay these "peaker" plants just to stay in business, so they'll be around the next time demand surges.	*causes...* Generation Capital Costs **Capacity Costs**: power plants, etc.

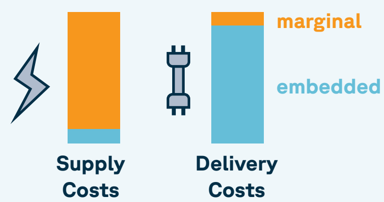
But generation is not the only infrastructure running at full tilt during the heat wave. The transmission line that brings electricity to their city, the distribution line that brings it to their home, and the substation that connects the two may also be approaching their **capacity**. By turning on their air conditioner at this moment, the family is contributing to the need for the utility to upgrade these components so they can handle even higher demand in the future.	*causes...* Transmission Capital Costs **Capacity Costs**: upgrading high-voltage lines, bulk substations, etc. Distribution Capital Costs **Capacity Costs**: upgrading feeders, transformers, etc.
During most of the year, however, the family is simply benefiting from the transmission and distribution infrastructure that is *already built*, not causing the need for upgrades. How are these "historical" capital costs to be paid for?	*benefits from...* Transmission Capital Costs **Capacity Costs**: existing high-voltage lines, bulk substations, etc. Distribution Capital Costs **Capacity Costs**: existing feeders, transformers, etc.

MARGINAL VS. EMBEDDED COSTS

This example shows that cost-causation is not so straightforward.

Some costs are caused directly by customer usage in the present, like energy costs and new T&D capacity upgrades. These are called **marginal costs**.

Other costs — like most transmission and distribution infrastructure — were caused in the past by yesterday's customers, and simply have to be paid for in the future by today's customers. These are called **embedded costs**.



Supply costs (both energy and generation capacity) are mostly marginal. Delivery costs are mostly embedded capital costs (already built T&D infrastructure)

Marginal costs

The costs of generating or delivering the next unit of electricity. In other words, supply or delivery costs that are caused by customers choosing to consume an additional kWh at particular times.

Embedded costs

Costs that have already been incurred, and must be recovered from customers regardless of how much customer electricity they use, or when they use it. Mostly consists of the delivery costs associated with T&D infrastructure that has already been built.

	Marginal costs	Embedded costs
Generation	**Capacity costs**: new plants and storage **Operating costs**: fuel and consumables (energy costs)	
Transmission	**Capacity costs**: new lines and substations	**Capacity costs**: existing lines and substations **Operating costs**: maintenance, vegetation management, property taxes
Distribution	**Capacity costs**: new feeders and transformers **Connection costs**: meters, service drops **Operating costs**: billing, customer service, meter reading	**Capacity costs**: existing feeders and transformers **Operating costs**: maintenance, storm restoration, property taxes

In fact, the vast majority of transmission and distribution costs that utilities need to recoup from customers via their bill are **embedded**: the infrastructure is already built, and it has to be paid for, regardless of what customers do going forward.[56]

56 Similarly, most T&D *operating* costs are fixed, and therefore embedded: the utility will need to trim trees and restore service after storms regardless of how customers consume electricity during the year.

Only a small fraction of delivery costs are **marginal** — new capacity upgrades that haven't been committed to yet, and that could be avoided or deferred if fewer customers stress the grid at peak times in the coming year.

Supply costs, on the other hand, are overwhelmingly **marginal**.

Why are most supply costs marginal, and most delivery costs embedded?

Generation capital and operating costs are short-lived: customers pay for them shortly after causing them. Households pay for the energy costs they caused that month on their bill at the end of the month. Generators receive the capacity payments they need to stay in business for another year during that same year.

Transmission and distribution capital expenses, which dominate delivery costs, are long-lived: they get paid back over decades. This is because infrastructure projects are expensive, and they are long-lasting, so customers are charged for them across many years in order to make delivery rate more affordable.

In any given year, the utility will charge customers their "yearly payment" for each one of thousands of infrastructure projects built over decades — all the projects that are still in service, but haven't been fully paid for yet. This is known as recovering depreciation on rate base assets through delivery **rates**

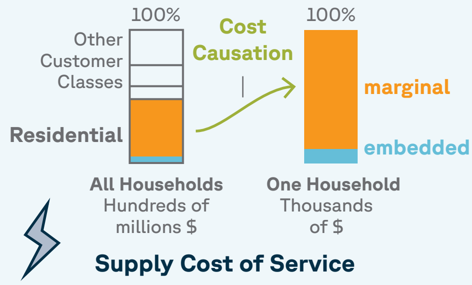
The latest wave of T&D capacity upgrades that will be triggered by the forthcoming summer peak — the marginal T&D capacity costs — will therefore make up a very small fraction of all the embedded capital costs that the utility still needs to recoup from customers.

COST OF SERVICE

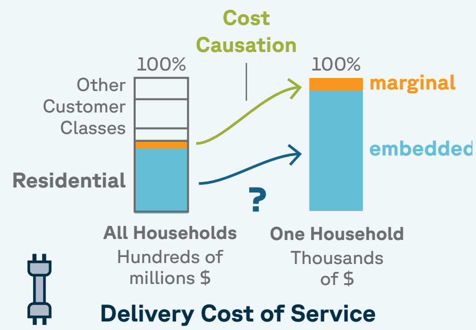
To find a customer's cost of service, we must calculate their marginal costs — the new costs they caused over the past year — and add them to their "fair share" of the utility's embedded costs — largely for existing infrastructure that they likely benefited from over the past year, but may or may not have caused originally.

This distinction matters, because cost-causation works very differently for marginal costs than for embedded ones. For **marginal costs**, cost-causation is both measurable and uncontroversial (at least in principle): you can observe how much electricity a customer consumed each hour, calculate the energy and capacity costs they caused, and allocate accordingly.

But determining a customer's fair share of **embedded costs** is harder — and more contentious.



Marginal supply costs are allocated to households based on hourly usage (cost causation).



Cost allocation determines residential revenue requirement. Marginal delivery costs are allocated to households based on usage during peak hours (cost causation). Embedded cost allocation requires normative choice among different approaches.

Some practitioners — including most utilities — believe cost-causation is still the right principle.[57] A customer's current cost-causation (as measured by their marginal T&D costs), they argue, is a reasonable proxy for how customers like them contributed to past infrastructure needs.

But even proponents who agree with this principle acknowledge that it is difficult to measure in practice: which customers caused a particular transformer to be upgraded 30 years ago? Are they even still around?[58]

Other experts, including many economists, argue that cost-causation is not just hard to apply to embedded costs — it is the *wrong* principle for them.[59] Their reasoning starts from what cost-causation means in practice: to actually bill customers according to the costs they cause, since that is the ultimate goal of determining their cost of service, you need prices (or rates) that reflect those costs.

When costs are still up for grabs — when a customer's behavior today can change the costs that will be incurred tomorrow — this works well. Prices that reflect these marginal costs achieve the goal of billing each customer in line with their cost-causation, and they have a productive secondary effect:

57 Utilities in most states use Embedded Cost of Service (ECOS) to split costs among customer classes: they measure each class's *recent* contribution to system demand, and divide the utility's embedded revenue requirement in proportion to those shares (Lazar et al. 2020, p. 69). The implicit assumption: current cost-causation is a fair proxy for historical cost-causation.

58 This is part of why utilities apply cost-causation at the level of broad customer classes — residential, commercial, industrial — rather than to individual customers. You can estimate that the residential class as a whole is responsible for a certain share of historical infrastructure costs. Tracing those costs to individual households is much more difficult.

59 This view has broad support among academic economists; see, (Borenstein 2016), (Pérez-Arriaga et al. 2017), and (Faruqi and Brown 2014). These three disagree about which marginal costs belong in cost-reflective charges and how embedded costs should be split — but agree that historical cost-causation is not the right principle for doing so.

customers who see higher prices during hours when capacity upgrades are at risk will shift load away from those hours, reducing the need for the next wave of infrastructure and right-sizing future **capital costs**.[60] Cost-causation, applied to marginal costs, is both fair and *useful*.

But once the infrastructure is built, those **embedded costs** are fixed: charging today's customers based on who caused them in the past doesn't change those costs — it can't. The question is no longer *who caused them originally*, but *how to divide them fairly among the customers who benefit from the grid today*. One answer is **equally** — a per-customer lump sum, on the grounds that everyone benefits from the existing grid and no one's current behavior can change what it cost to build. Another is progressively, based on **ability to pay**, on the grounds that since these costs must be paid regardless, distributing them equitably does the least harm.[61]

The choice of how to allocate embedded costs is ultimately a normative decision, and an unavoidable one.[62]

And when it comes to this task, cost-causation — a widely accepted principle for the allocation of marginal costs — is contested in theory and hard to achieve in practice.

60 The same applies to energy costs: if the prices customers pay for energy reflect their underlying marginal costs, some will shift their demand to hours with lower costs, thereby lowering their bills for the same energy consumed.

61 These aren't novel proposals. The residual-allocation problem has a long literature with several recognized approaches, including lump sums, equi-proportional marginal cost (EPMC), and Ramsey pricing; see (NARUC 1992, ch. 11). Ability-to-pay is treated less as a method and more as an adjustment factor in the cost-allocation literature; see (Lazar et al. 2020, p. 82).

62 To measure cross-subsidies between customer groups, we need to determine the delivery cost of service of those groups. To determine their delivery cost of service, we need to decide how to allocate embedded costs — which make up the vast majority of deliver costs — to individual customers.

How we allocate embedded costs in this report

In this report, we take the lump-sum approach: each customer's share of embedded delivery costs is treated as approximately equal.

Why not adopt the cost-causation view instead? Consider what that would require. You would need to measure how much of the existing infrastructure each heat pump customer "caused." No one has historical data tracing individual households to specific infrastructure investments, so you would do what utilities typically do: use each customer's *current* cost-causation as a proxy for their historical contribution to infrastructure needs. But this is where the approach breaks down for heat pump customers. Nearly all of them are retrofits — and installing a heat pump fundamentally changes a home's load profile. Their current cost-causation reflects their *post*-heat-pump load, but the infrastructure they would be paying for was built in response to their *pre*-heat-pump demand.

Rather than rely on a proxy that could produce misleading results, we allocate embedded delivery costs equally across all customers and let **marginal T&D capacity costs** — the costs each customer is actually causing now, and the costs that matter for the grid going forward — be what differentiates their delivery **cost of service** for purposes of measuring cross-subsidies.

That is cost of service — the costs the utility incurs to serve each customer. The next question is how those costs are recovered. The answer is bills, which are *supposed* to collect each customer's cost of service. A customer's electric bill has two sections, each designed to recover a different set of costs:

- **Supply bills** pay for generation — both the operating costs of producing electricity (energy costs) and the capital costs of keeping power plants available to meet demand (generation capacity costs).
- **Delivery bills** pay for the poles and wires — both the capital and operating costs of the transmission and distribution infrastructure that carries electricity from generators to homes.[63]

The cost composition of each side is very different. The vast majority of generation costs are marginal: energy costs change hour by hour based on how much electricity customers consume, and generation capacity costs are set annually through competitive auctions that reflect the cost of keeping enough power plants available to meet peak demand.[64] As a result, a customer's supply cost of service, and the supply side of the bill that is supposed to collect it, is driven almost entirely by what customers are consuming right now.

The delivery side is the opposite. As we saw above, the vast majority of transmission and distribution costs are embedded — the infrastructure is already built and has to be paid for regardless of what customers do. Only a small fraction of delivery costs are marginal: the next wave of capacity upgrades triggered by rising peak demand. A customer's delivery cost of service, and the delivery side of the bill that is supposed to collect it, is therefore dominated by their "fair share" of embedded costs, with marginal T&D costs adding a relatively small amount on top.

63 Strictly speaking, a small slice of transmission costs gets recovered on the supply section of the bill instead of the delivery section: NYISO passes through the embedded cost of the New York Power Authority's transmission system (the **NYPA Transmission Adjustment Charge**, or NTAC), along with the cost of new transmission lines built by independent developers to relieve congestion and meet state policy goals (the **Transco Facilities Charge**, or TFC), by bundling both into the wholesale price it charges utilities. See §14.2.2 and §6.13 of NYISO's Open Access Transmission Tariff (NYISO 2026b) for more details.

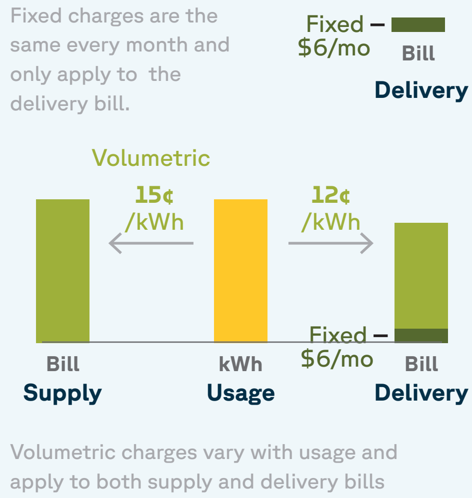
64 Unlike transmission and distribution infrastructure, power plants compete in a market. Customers pay the market-clearing price for energy and capacity — not any individual plant's embedded costs. If revenues from energy and capacity auctions don't cover a plant's costs, it can shut down. So customers are not on the hook for keeping specific generators in business the way they are for keeping specific poles and wires in service.

RATES

Bills *attempt* to recover each customer's cost of service — but they rarely succeed, because bills are calculated using **rates**, and rates are imperfect proxies for costs.

Residential customers face two kinds of rates:

- **Fixed charges**: a flat dollar amount per month, regardless of how much electricity the customer uses. These only appear on the delivery side of the bill. In many utilities, these only cover customer-related capacity and operating costs — meters, service lines, billing, meter reading, etc.
- **Volumetric charges**: a price per kWh of electricity consumed. These appear on *both* sides of the bill — supply and delivery. Volumetric charges can either be **flat** — the same price at all hours — or **time-varying** — prices that change over time.

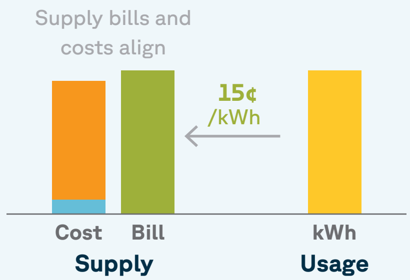


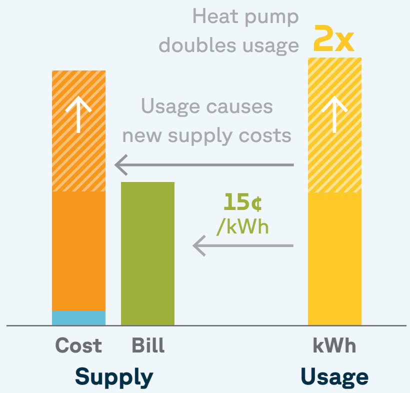
Volumetric rates and marginal supply costs

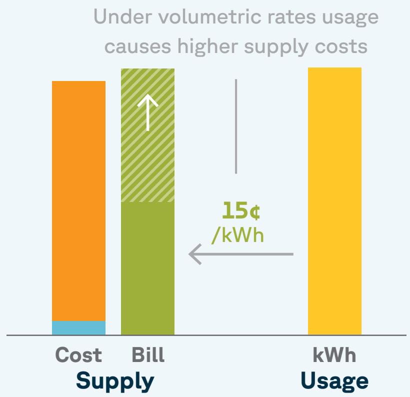
On the **supply** side, volumetric rates make intuitive sense.

Supply costs are mostly **marginal**: the more kWh a customer consumes, the more electricity that needs to be generated and the more generation capacity is needed.

A per-kWh price tracks this relationship well — customers who consume **more electricity** cause more **supply costs**, and pay proportionally higher **supply bills**.







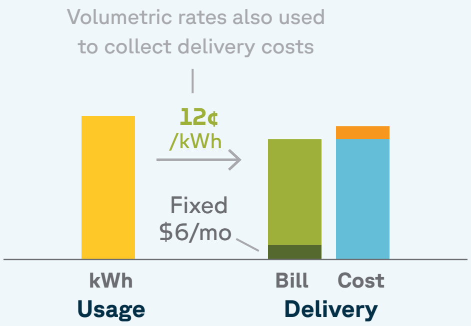
Volumetric rates and marginal delivery costs

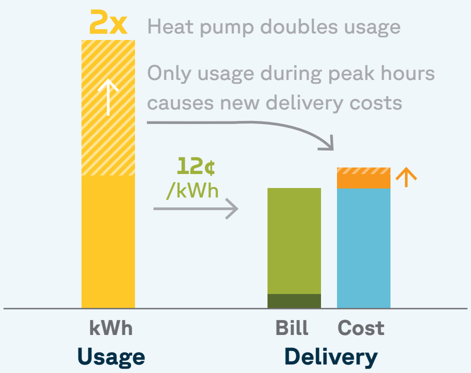
For all utilities in New York, volumetric rates also feature heavily on the **delivery** side, the part of the bill that is meant to collect T&D embedded costs — the more electricity a customer happens to consume, the more they pay for the poles and wires.

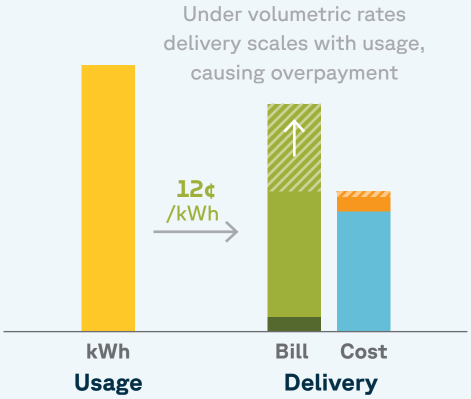
But here the logic breaks down: delivery costs do not scale with how much electricity a customer uses *in general*. Marginal delivery costs are only incurred during a handful of peak hours — typically summer heat waves — when the grid is strained and upgrades become necessary. The rest of the time, customers are simply using embedded infrastructure that is already built.

Yet a flat volumetric delivery rate charges customers *as if* delivery costs grew with every kWh they consumed. The rate doesn't distinguish between a kWh consumed during a summer peak that strains the grid and a kWh consumed on a mild winter evening when there is ample capacity. It charges the same price for both — a customer who doubles their electricity use will pay roughly double for delivery bills, even if none of that new consumption falls during peak hours and they haven't triggered a single dollar of new delivery costs.

This mismatch — volumetric rates applied to costs that don't scale with volume — is the source of the fairness problem at the heart of this report.





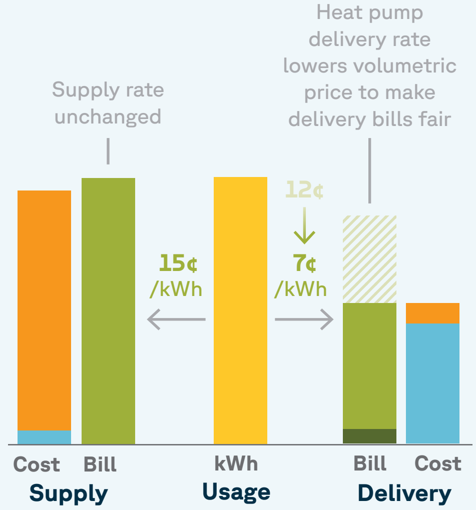


The fairness problem

We established earlier that a widely held principle of fairness in rate design is that each customer's bill should match their cost of service — the costs they impose on the system. It follows that when a rate systematically causes a group of customers to pay *more* on their bills than their cost of service, that group has a fairness problem. They are being overcharged, and the excess revenue they contribute effectively subsidizes everyone else.

As we saw on p. 20, this is precisely what is happening to heat pump customers on the delivery side of the electric bill. Because delivery costs are largely recovered through volumetric rates, heat pump customers — who consume significantly more electricity after the switch — pay far more for the poles and wires than they actually cost to serve.

The solution requires two steps: **Cost allocation** — determining the correct delivery revenue to collect from heat pump customers, based on their actual cost of service (p. 29) — followed by **Rate design** that collects that amount without overcharging them (p. 30).



The efficiency problem

Solving the fairness problem means collecting the right *amount* from each group of customers. But there is a second problem that fairness alone does not address: are customers aware of *when* they are incurring marginal costs?

Under a **flat volumetric rate**, a customer who runs their heat pump at 3 AM on a mild night pays the same price per kWh as one who cranks the air conditioning during a summer heat wave that strains the grid. The rate collects revenue — but it sends no signal about when electricity is cheap or expensive to produce, or when consumption risks triggering costly infrastructure upgrades. If prices don't distinguish between cheap hours and expensive hours, customers have no reason to shift their load — and load that doesn't respond to costs leads to **waste** and unnecessarily increases the costs of the system for everyone.

This is the **economic efficiency** problem, and it has two distinct flavors:

1. **Consumption efficiency**: when prices reflect the hour-by-hour marginal cost of generating electricity, known as **marginal energy costs**, customers use more when it's cheap to produce (like when the sun is shining) and less when it's expensive (like when peakers are running).

2. **Investment efficiency**: when prices reflect the marginal cost of expanding grid capacity, known as **marginal** generation and **T&D capacity costs**, customers reduce their

Marginal energy costs

The operating cost of generating an additional kWh of electricity at a particular time. Marginal energy costs vary hour by hour with demand and the mix of generators running: they are low when abundant renewables are on the grid or demand is slack, and high when expensive peaker plants are running to meet peak load.

Marginal generation capacity costs

The capacity cost associated with triggering the construction of a new megawatt of generation capacity at a particular time. Zero most hours of the year, and high during system-wide peak hours.

Marginal T&D capacity costs

The capacity cost associated with triggering the construction of a new megawatt of transmission or distribution capacity at a particular time. Zero most hours of the year, and high during peak hours for the infrastructure component that is at capacity.

electricity use during peak demand periods, reducing the need for the next wave of infrastructure investment — in generation, transmission, and distribution alike.

A rate that exposes customers to prices reflecting the underlying marginal costs of energy and infrastructure — costs that change over time and by location — is called a **cost-reflective** rate. Cost-reflective rates promote economic efficiency, which can benefit customers in two distinct ways:

Why is economic efficiency desirable?

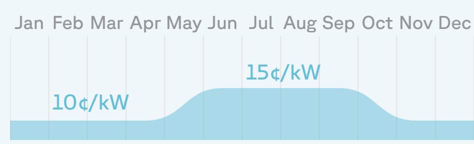
- **Avoided energy costs**: By lowering their supply and delivery bills *today*, to the extent they can shift their electricity use to off-peak periods. This also benefits climate and health, because low-cost hours tend to come from renewable sources, whereas high-cost hours tend to come from high-polluting peaker plants.
- **Capacity deferral benefits**: By lowering their supply and delivery bills *tomorrow*, to the extent that load shifting slows the growth of peak demand, reducing future investments in generation, transmission, and distribution capacity.

Cost-reflective rates

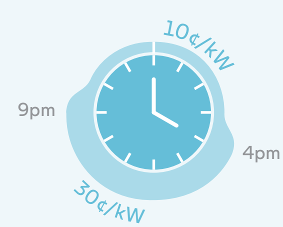
In this report, we define a time-varying rate as a volumetric rate whose ¢/kWh price changes over time.

Examples of time-varying rates include:

- **Seasonal rates:** prices that vary by season and are set ahead of time
- **Time-of-use (TOU):** prices that vary by time of day and are set ahead of time (e.g., 30¢/kWh during the "on-peak" period of 4 p.m. to 9 p.m., and 10¢/kWh during the "off-peak" period of 9 p.m. to 4 p.m.). Seasonal and TOU rates can be combined by charging different on-peak and off-peak prices in different seasons.
- **Critical peak pricing (CPP):** prices that are much higher during a few days of the year; unlike seasonal and TOU rates, these higher prices are intended to respond to



Seasonal rates: e.g., 15¢/kWh in the summer, and 10¢/kWh in the winter



Time-of-use (TOU): e.g., 30¢/kWh during the "on-peak" period of 4 p.m. to 9 p.m., and 10¢/kWh during the "off-peak" period of 9 p.m. to 4 p.m.).

real-time grid conditions, and are usually announced by the utility shortly before they occur.

- **Real-time pricing (RTP):** prices that change hour by hour, usually to reflect the cost of generating electricity during these peak hours.

We define a **cost-reflective rate** as a time-varying rate whose volumetric prices are temporally correlated with the marginal energy, generation capacity, and T&D capacity costs associated with serving customers in a particular utility territory.[65]

For a rate to be cost-reflective, it must be time-varying: if the prices are static, they cannot reflect underlying costs, which change over time. But not every time-varying rate is cost-reflective: its prices might change over time, but not in a way that is correlated with marginal costs.

The time-varying rates above are listed in order of *potential* cost-reflectiveness: a seasonal rate can only reflect average cost differences between seasons, whereas real-time pricing could reflect the actual hourly cost of generating electricity and upgrading the grid in any given hour.

Of these options, time-of-use (TOU) rates, which set different prices for on-peak and off-peak hours, are the version available in most New York utilities. In practice, these existing TOU rates are only *partially* cost-reflective, for two distinct reasons:

1. On-peak and off-peak prices are set ahead of time rather than responding to real-time conditions. On any given day, the on-peak price will likely overshoot or undershoot the underlying marginal energy, generation capacity, and T&D capacity costs.

2. Utilities largely recover **embedded delivery costs** through the **volumetric** on-peak and off-peak prices, rather than through **fixed charges**, which inflates both on- and off-peak delivery prices above the underlying marginal T&D capacity costs.

65 By underlying cost, we mean **marginal energy costs** and **marginal T&D capacity costs**, also known as short-run and long-run marginal costs in the economics literature. For simplicity, we avoid using the term marginal cost here, but we discuss it in detail on p. 61.

Designing a cost-reflective TOU rate

A well-designed TOU rate needs to find the peak-period start hour, duration, and price level that most closely matches the marginal energy, generation capacity, and T&D capacity costs for that utility, over the entire season, and do the same for the off-peak period (Figure 40).

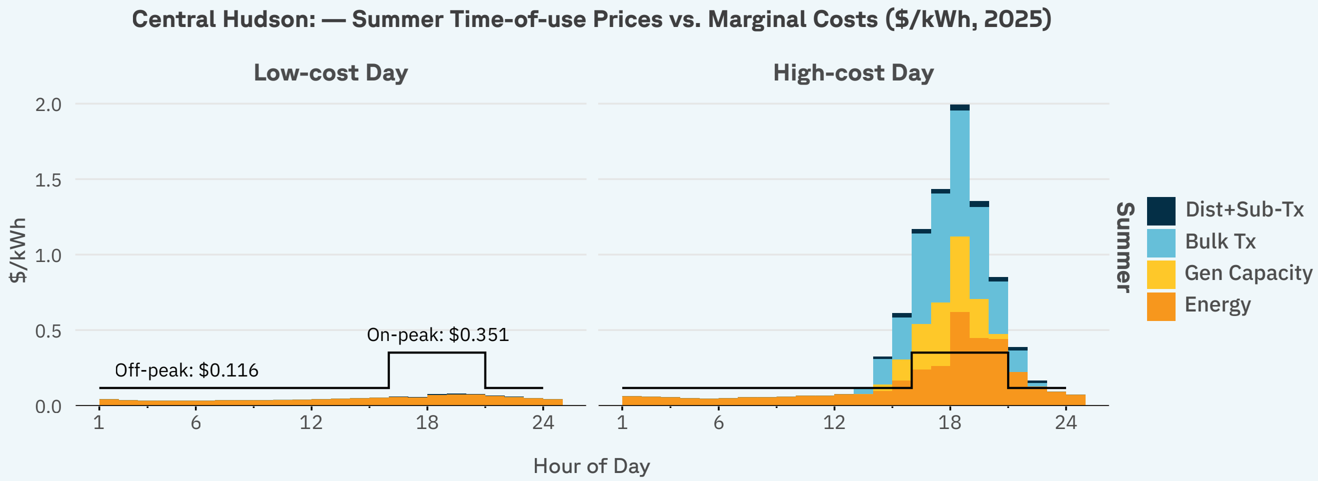


Figure 40: Central Hudson summer: hourly marginal costs (stacked bars) vs. calibrated TOU rate (black line)

Figure 40 shows the optimal summer time-of-use rate for heat pump customers in Central Hudson.

The off-peak period costs $0.134/kWh. The 5-hour on-peak period, which starts at 17pm, sets the price at $0.208/kWh, or 1.6x the off-peak price.

On cooler days, when demand is well below the peak, energy costs average $0.084/kWh, lower than even the off-peak rate, and capacity costs are zero. On the hottest days, energy costs shoot up to $0.131/kWh, above the on-peak rate, and are joined by capacity costs that reach $0.482/kWh in peak hours.

TOU rates are clearly more cost-reflective than a flat rate, which would look like a straight line impervious to costs. But they are less reflective than a real-time-price that follows true marginal costs, because the on-peak price must be fixed for the entire season: the on-peak price is set at the level that follows the marginal cost as much as possible *on average*, but on any given day, it may overshoot or undershoot the marginal cost.

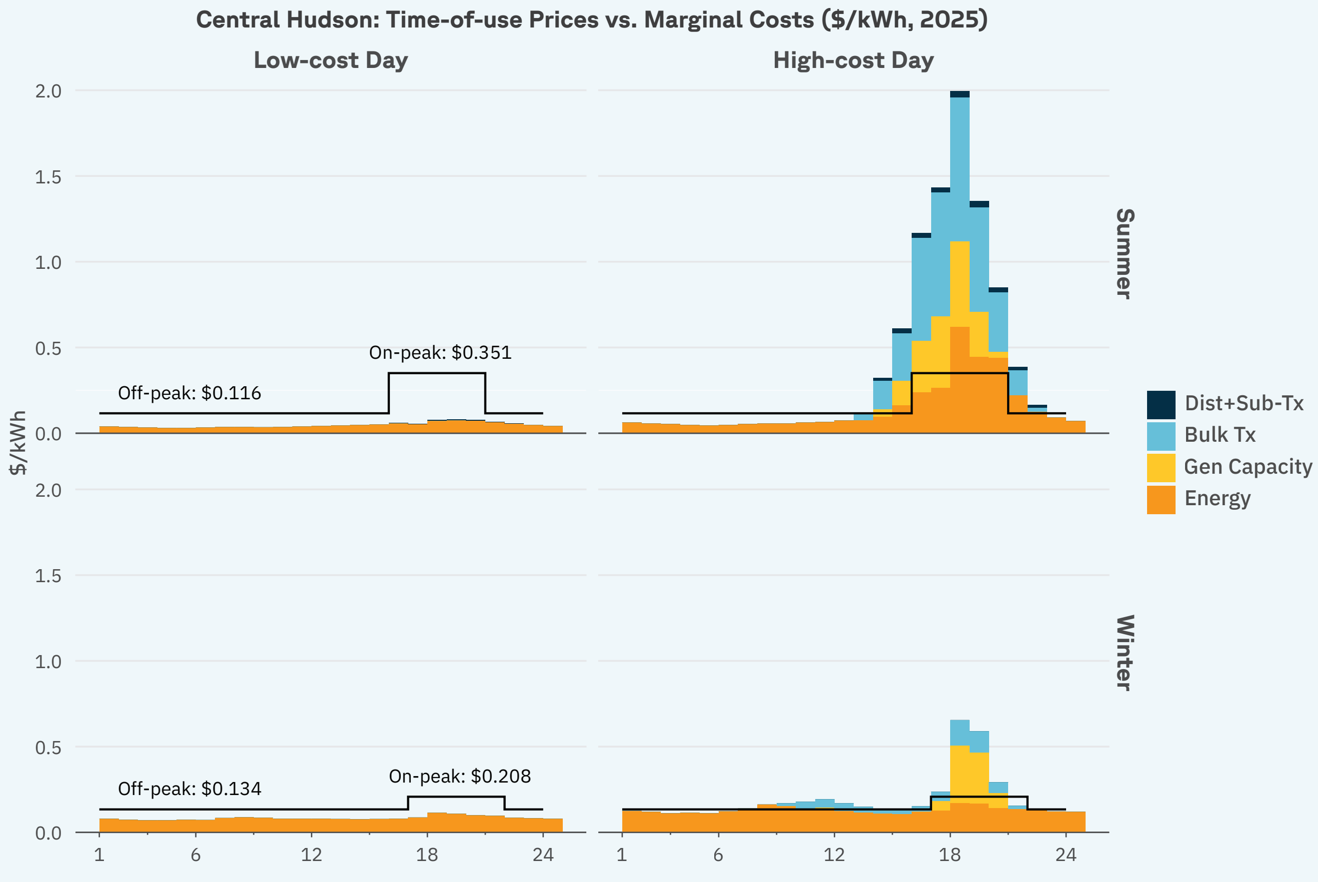


Figure 41: Central Hudson summer and winter: hourly marginal costs (stacked bars) vs. calibrated TOU rate (black line)

Figure 41 adds the optimal winter TOU rate for heat pump customers in Central Hudson. While the window is still 5 hours long, it starts 1 hour later than the summer window. The off-peak price in winter is 1.8 cents higher than in summer, reflecting higher average energy costs in cold months. The on-peak price in winter is 14.3 cents *lower* than in summer, reflecting the much higher marginal generation, transmission, and distribution capacity costs in hot months.

Fairness and efficiency are distinct problems

This brings us to a crucial distinction. Solving the **fairness** problem — making sure each group of customers pays the right *total* — is not the same as solving the **efficiency** problem — making sure prices *reflect costs as they happen*. A rate can achieve one without the other.

A rate is **cost-based** (fair) if it bills each group of customers in line with their cost of service. A rate is **cost-reflective** (efficient) if it exposes customers to prices that track marginal costs over time.

These are independent properties:

A rate can be **cost-reflective without being cost-based**. When a utility switches all customers from **flat** to time-of-use rates — as PSEG Long Island recently did — customers are exposed to a degree of temporal cost-reflectivity: if the TOU rate is well-designed, prices are more aligned with the hour-by-hour fluctuation in marginal energy, generation capacity, and T&D capacity costs. But as long as embedded costs, which make up the majority of the delivery revenue requirement, continue to be collected through volumetric rates — even time-varying ones — electric heating customers will continue to overpay, on average, and fossil heating customers to underpay, relative to their cost of service. The rate sends better price signals, which improves **efficiency**, but it doesn't fix the **fairness** problem.

A rate can also be **cost-based without being cost-reflective**. Imagine if heat pump and fossil heating customers each paid all of their delivery costs through fixed charges equal to the average cost of service of their group: $90 per month for heat pump customers, and $90 per month for fossil heating customers (we derive these figures in the analysis below). This rate would be cost-based — the average overpayment or underpayment would be zero for both groups. But it would not be cost-reflective, because it would not expose customers to different prices at different hours. There would be no incentive to minimize the buildout of the grid in the future (marginal generation and T&D capacity costs) and no ability to access cheaper electrons from solar and wind in the present (marginal energy costs). Fair, but not efficient.

Flat volumetric rates — the status quo for most residential customers — are the worst of both worlds: neither fair nor efficient. They overcharge electric heating customers relative to the cost of serving them, so they are not cost-based. They don't change over time, so they are not cost-reflective. Flat rates create unfair cross-subsidies *and* fail to send customers the price signals they need to make cost-aware decisions.

But it is possible to design rates that are both **fair** and **efficient**: we design such a rate, a seasonal time-of-use rate for heat pump customers, in p. 46.

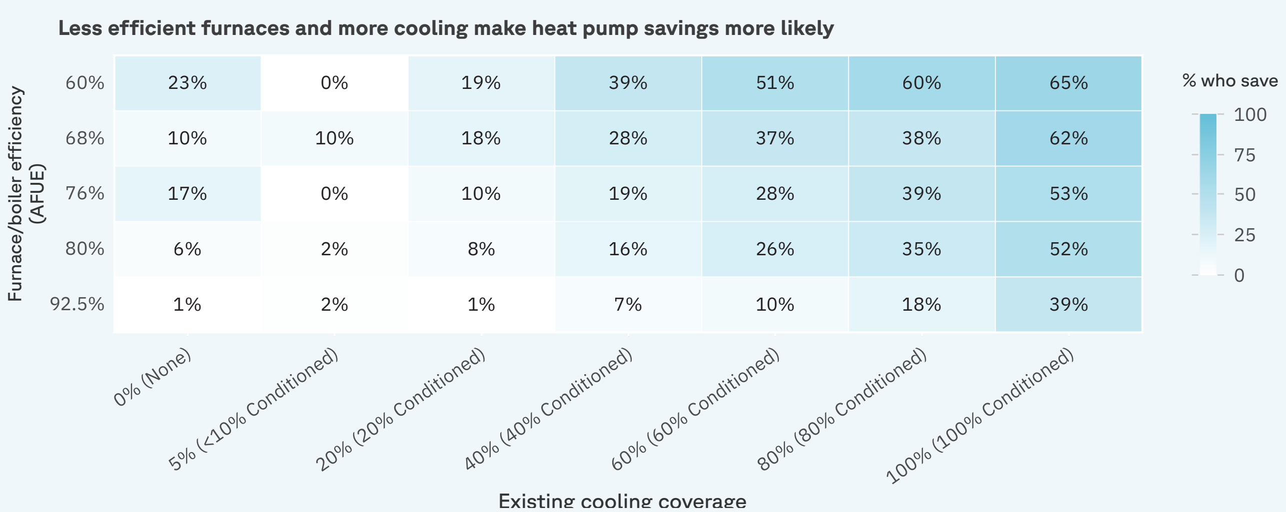
In fact, meeting the state's building electrification goals hinges on doing so: cost-based rates would lower heat pump bills by paying for *already built* infrastructure more fairly, while cost-reflective rates could lower heat pump bills further by allowing customers to pre-cool and pre-heat their homes when electrons are cheap — while also reducing the amount of infrastructure the state will need to build as it electrifies, thereby limiting bill growth for all.

Appendix 2: Which households save when they switch to heat pumps?

Under default rates, 27% of gas-heated households would save on their annual energy bills after switching to a heat pump. What distinguishes these households from the rest? Two building characteristics stand out: the efficiency of the existing furnace or boiler, and whether the home already has air conditioning.

Homes with less efficient fossil heating systems — older furnaces and boilers with lower energy efficiency ratings — spend more on gas, giving the heat pump a larger bill to offset. And homes that already have cooling equipment may lower their cooling load when they install a heat pump (since heat pumps are often more efficient than the existing cooling system). Together, these two factors explain much of the variation in bill outcomes: among gas-heated homes with the least efficient furnaces (60% AFUE) and full air conditioning, roughly two-thirds would save even under today's rates. Among homes with the most efficient condensing furnaces (92.5% AFUE) and no existing cooling, almost none would (Figure 42).

Figure 42: Share of natural gas-heated households in NYS whose annual combined energy bill (electricity + gas) would be lower after installing a cold-climate heat pump, grouped by pre-upgrade furnace/boiler AFUE rating and share of conditioned floor area with existing cooling equipment. Bills are calculated under default electric rates. Source: NREL's ResStock 2024.2, utility gas and electricity tariffs.



Appendix 3: Findings by utility

The statewide charts, tables, and figures in the Findings section are all based on utility-level analysis performed by Switchbox. This section shows the report's key findings for each of the state's electrical utilities.

NUMBER OF HOUSEHOLDS

A utility-level breakdown of New York's residential electricity customers.

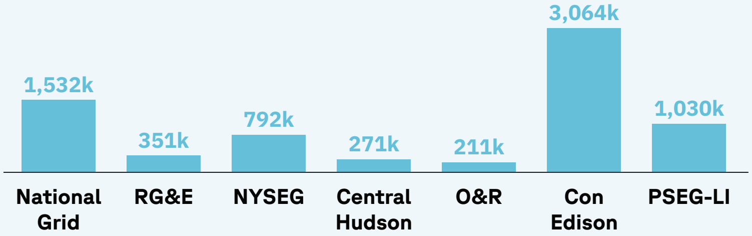
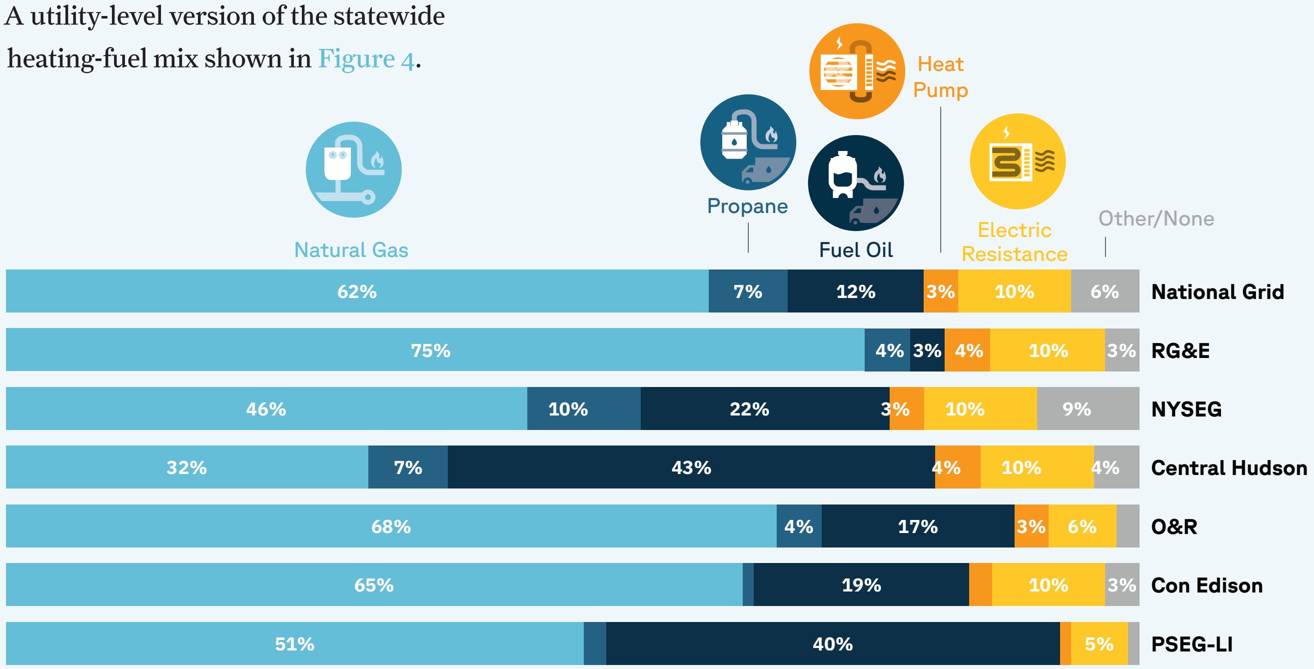


Figure 43: Number of households by electric utility

NUMBER OF HOUSEHOLDS BY HEATING FUEL

Figure 44: Percentage of households by primary heating fuel, by utility

A utility-level version of the statewide heating-fuel mix shown in Figure 4.



CHANGE IN ELECTRICITY USE POST-HEAT PUMP

The percent increase in annual electricity consumption after switching to a heat pump varies by utility territory and by whether the home already had air conditioning.

	Baseline cooling		
	Full cooling	Partial cooling	No cooling
Central Hudson	61%	118%	151%
Con Edison	35%	87%	146%
NYSEG	87%	145%	175%
National Grid	85%	153%	195%
O&R	52%	102%	127%
PSEG-LI	52%	104%	145%
RG&E	81%	134%	191%

Table 9: Median percent increase in annual electricity consumption for fossil-heated households after switching to a heat pump, by utility territory and baseline cooling status (full, partial, or none). Based on ResStock 2024 hourly load profiles, pre- and post-heat-pump, for households that currently heat with natural gas, oil, or propane.

AVERAGE CROSS-SUBSIDY

Total customer count for tables 10-16 from 2024 EIA-861, subclass customer counts estimated using RECS 2020. Building loads and utility assignments from ResStock. Cost-of-service from Switchbox analysis.

A utility-level version of the statewide average cross-subsidy shown in Table 1.

Central Hudson's heat pump customers are overpaying by an average of $1,733 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	3.9%	9.3%	21,050 kWh / year	$3,323 / year	$1,590 / year	$1,733 / year	109.0%
Electric resistance	10.3%	19.8%	16,929 kWh / year	$2,716 / year	$1,548 / year	$1,169 / year	75.5%
Natural gas	32.1%	22.9%	6,291 kWh / year	$1,181 / year	$1,534 / year	−$354 / year	−23.1%
Delivered fuels	49.7%	45.1%	7,998 kWh / year	$1,420 / year	$1,546 / year	−$126 / year	−8.1%
Other	3.9%	2.9%	6,636 kWh / year	$1,236 / year	$1,538 / year	−$303 / year	−19.7%
All customers	100.0%	100.0%	8,826 kWh / year	$1,544 / year	$1,544 / year	$0 / year	0.0%

Table 10: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for Central Hudson. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

Con Edison's heat pump customers are overpaying by an average of $594 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	2.4%	4.2%	9,188 kWh / year	$1,682 / year	$1,088 / year	$594 / year	54.6%
Electric resistance	9.7%	19.7%	10,674 kWh / year	$1,898 / year	$1,080 / year	$817 / year	75.6%
Natural gas	64.8%	57.7%	4,664 kWh / year	$987 / year	$1,073 / year	−$86 / year	−8.0%
Delivered fuels	20.5%	16.5%	4,222 kWh / year	$915 / year	$1,068 / year	−$153 / year	−14.4%
Other	2.7%	1.9%	3,791 kWh / year	$845 / year	$1,063 / year	−$218 / year	−20.5%
All customers	100.0%	100.0%	5,239 kWh / year	$1,073 / year	$1,073 / year	$0 / year	0.0%

Table 11: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for Con Edison. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

National Grid's heat pump customers are overpaying by an average of $898 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	3.4%	7.6%	18,927 kWh / year	$1,835 / year	$937 / year	$898 / year	95.8%
Electric resistance	10.2%	21.9%	17,918 kWh / year	$1,760 / year	$930 / year	$830 / year	89.3%
Natural gas	61.9%	47.1%	6,364 kWh / year	$755 / year	$925 / year	−$170 / year	−18.3%
Delivered fuels	18.9%	18.0%	7,974 kWh / year	$890 / year	$928 / year	−$38 / year	−4.1%
Other	5.7%	5.3%	7,796 kWh / year	$877 / year	$928 / year	−$51 / year	−5.5%
All customers	100.0%	100.0%	8,352 kWh / year	$927 / year	$927 / year	$0 / year	0.0%

Table 12: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for National Grid. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

NYSEG's heat pump customers are overpaying by an average of $1,045 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	3.4%	7.5%	19,353 kWh / year	$2,208 / year	$1,163 / year	$1,045 / year	89.8%
Electric resistance	9.6%	22.9%	20,901 kWh / year	$2,362 / year	$1,159 / year	$1,203 / year	103.8%
Natural gas	46.3%	35.0%	6,655 kWh / year	$939 / year	$1,151 / year	−$212 / year	−18.4%
Delivered fuels	31.9%	27.5%	7,586 kWh / year	$1,035 / year	$1,153 / year	−$119 / year	−10.3%
Other	8.8%	7.1%	7,029 kWh / year	$979 / year	$1,152 / year	−$173 / year	−15.0%
All customers	100.0%	100.0%	8,789 kWh / year	$1,153 / year	$1,153 / year	$0 / year	0.0%

Table 13: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for NYSEG. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

O&R's heat pump customers are overpaying by an average of $878 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	3.1%	6.1%	15,738 kWh / year	$2,145 / year	$1,267 / year	$878 / year	69.3%
Electric resistance	6.2%	11.8%	15,432 kWh / year	$2,086 / year	$1,252 / year	$833 / year	66.5%
Natural gas	68.4%	58.7%	6,917 kWh / year	$1,117 / year	$1,245 / year	–$128 / year	–10.3%
Delivered fuels	20.6%	21.9%	8,541 kWh / year	$1,307 / year	$1,256 / year	$52 / year	4.1%
Other	1.7%	1.5%	6,936 kWh / year	$1,128 / year	$1,245 / year	–$117 / year	–9.4%
All customers	100.0%	100.0%	8,053 kWh / year	$1,248 / year	$1,248 / year	$0 / year	0.0%

Table 14: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for O&R. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

PSEG-LI's heat pump customers are overpaying by an average of $988 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	1.4%	3.0%	19,301 kWh / year	$2,149 / year	$1,161 / year	$988 / year	85.2%
Electric resistance	4.6%	9.1%	17,365 kWh / year	$1,930 / year	$1,124 / year	$806 / year	71.7%
Natural gas	51.2%	43.3%	7,476 kWh / year	$995 / year	$1,126 / year	–$131 / year	–11.7%
Delivered fuels	42.2%	44.0%	9,216 kWh / year	$1,181 / year	$1,141 / year	$40 / year	3.5%
Other	0.7%	0.6%	8,287 kWh / year	$1,059 / year	$1,126 / year	–$67 / year	–5.9%
All customers	100.0%	100.0%	8,835 kWh / year	$1,133 / year	$1,133 / year	$0 / year	0.0%

Table 15: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for PSEG-LI. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

RG&E's heat pump customers are overpaying by an average of $871 per year

Heating source	% of customers	% of consumption	Avg. consumption	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	4.4%	10.8%	21,699 kWh / year	$1,816 / year	$945 / year	$871 / year	92.2%
Electric resistance	10.5%	22.4%	19,091 kWh / year	$1,628 / year	$936 / year	$692 / year	74.0%
Natural gas	74.9%	58.1%	6,901 kWh / year	$794 / year	$929 / year	–$136 / year	–14.6%
Delivered fuels	7.5%	6.6%	7,766 kWh / year	$856 / year	$931 / year	–$75 / year	–8.1%
Other	2.7%	2.1%	6,830 kWh / year	$791 / year	$930 / year	–$139 / year	–14.9%
All customers	100.0%	100.0%	8,895 kWh / year	$931 / year	$931 / year	$0 / year	0.0%

Table 16: Average annual electric delivery bill, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for RG&E. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers.

TOTAL CROSS-SUBSIDY

A utility-level version of the statewide total cross-subsidy shown in Table 3.

Total customer count on tables 17-22 from 2024 EIA-861, subclass customer counts estimated using RECS 2020. Building loads and utility assignments from ResStock. Cost-of-service from Switchbox analysis.

Central Hudson's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $18 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	10,541	3.9%	9.3%	$35,022,942 / year	8.4%	$16,758,829 / year	4.0%	$18,264,113 / year	109.0%
Electric resistance	27,957	10.3%	19.8%	$75,931,570 / year	18.2%	$43,263,273 / year	10.3%	$32,668,297 / year	75.5%
Natural gas	87,078	32.1%	22.9%	$102,800,495 / year	24.6%	$133,595,873 / year	31.9%	−$30,795,377 / year	−23.1%
Delivered fuels	134,742	49.7%	45.1%	$191,372,890 / year	45.8%	$208,316,692 / year	49.8%	−$16,943,802 / year	−8.1%
Other	10,541	3.9%	2.9%	$13,023,745 / year	3.1%	$16,216,975 / year	3.9%	−$3,193,230 / year	−19.7%
All customers	270,859	100.0%	100.0%	$418,151,642 / year	100.0%	$418,151,642 / year	100.0%	$0 / year	0.0%

Table 17: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for Central Hudson. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

Con Edison's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $43 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	72,656	2.4%	4.2%	$122,187,707 / year	3.7%	$79,037,790 / year	2.4%	$43,149,917 / year	54.6%
Electric resistance	296,577	9.7%	19.7%	$562,764,752 / year	17.1%	$320,445,857 / year	9.7%	$242,318,895 / year	75.6%
Natural gas	1,985,520	64.8%	57.7%	$1,959,658,553 / year	59.6%	$2,131,074,771 / year	64.8%	−$171,416,218 / year	−8.0%
Delivered fuels	626,902	20.5%	16.5%	$573,536,953 / year	17.4%	$669,663,690 / year	20.4%	−$96,126,738 / year	−14.4%
Other	82,383	2.7%	1.9%	$69,634,774 / year	2.1%	$87,560,631 / year	2.7%	−$17,925,856 / year	−20.5%
All customers	3,064,038	100.0%	100.0%	$3,287,782,738 / year	100.0%	$3,287,782,738 / year	100.0%	$0 / year	0.0%

Table 18: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for Con Edison. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

National Grid's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $46 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	51,671	3.4%	7.6%	$94,817,229 / year	6.7%	$48,432,864 / year	3.4%	$46,384,365 / year	95.8%
Electric resistance	156,366	10.2%	21.9%	$275,256,715 / year	19.4%	$145,441,267 / year	10.2%	$129,815,448 / year	89.3%
Natural gas	947,897	61.9%	47.1%	$715,810,340 / year	50.4%	$876,607,001 / year	61.7%	−$160,796,661 / year	−18.3%
Delivered fuels	289,265	18.9%	18.0%	$257,556,974 / year	18.1%	$268,515,154 / year	18.9%	−$10,958,180 / year	−4.1%
Other	87,095	5.7%	5.3%	$76,371,569 / year	5.4%	$80,816,541 / year	5.7%	−$4,444,972 / year	−5.5%
All customers	1,532,294	100.0%	100.0%	$1,419,812,827 / year	100.0%	$1,419,812,827 / year	100.0%	$0 / year	0.0%

Table 19: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for National Grid. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

NYSEG's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $28 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	27,113	3.4%	7.5%	$59,876,243 / year	6.6%	$31,540,209 / year	3.5%	$28,336,034 / year	89.8%
Electric resistance	76,174	9.6%	22.9%	$179,933,387 / year	19.7%	$88,310,044 / year	9.7%	$91,623,342 / year	103.8%
Natural gas	366,670	46.3%	35.0%	$344,338,139 / year	37.7%	$422,185,154 / year	46.2%	−$77,847,016 / year	−18.4%
Delivered fuels	252,409	31.9%	27.5%	$261,117,479 / year	28.6%	$291,113,110 / year	31.9%	−$29,995,631 / year	−10.3%
Other	69,934	8.8%	7.1%	$68,443,080 / year	7.5%	$80,559,810 / year	8.8%	−$12,116,730 / year	−15.0%
All customers	792,300	100.0%	100.0%	$913,708,328 / year	100.0%	$913,708,328 / year	100.0%	$0 / year	0.0%

Table 20: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for NYSEG. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

O&R's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $5 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	6,618	3.1%	6.1%	$14,198,773 / year	5.4%	$8,387,766 / year	3.2%	$5,811,007 / year	69.3%
Electric resistance	12,981	6.2%	11.8%	$27,074,548 / year	10.3%	$16,256,849 / year	6.2%	$10,817,699 / year	66.5%
Natural gas	144,322	68.4%	58.7%	$161,162,258 / year	61.2%	$179,626,460 / year	68.2%	−$18,464,202 / year	−10.3%
Delivered fuels	43,526	20.6%	21.9%	$56,908,753 / year	21.6%	$54,657,570 / year	20.8%	$2,251,183 / year	4.1%
Other	3,564	1.7%	1.5%	$4,019,925 / year	1.5%	$4,435,612 / year	1.7%	−$415,687 / year	−9.4%
All customers	211,011	100.0%	100.0%	$263,364,257 / year	100.0%	$263,364,257 / year	100.0%	$0 / year	0.0%

Table 21: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for O&R. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

PSEG-LI's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $14 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	14,192	1.4%	3.0%	$30,500,187 / year	2.6%	$16,472,329 / year	1.4%	$14,027,859 / year	85.2%
Electric resistance	47,694	4.6%	9.1%	$92,035,316 / year	7.9%	$53,614,437 / year	4.6%	$38,420,879 / year	71.7%
Natural gas	527,192	51.2%	43.3%	$524,541,006 / year	44.9%	$593,845,906 / year	50.9%	−$69,304,899 / year	−11.7%
Delivered fuels	434,130	42.2%	44.0%	$512,841,332 / year	43.9%	$495,534,595 / year	42.5%	$17,306,737 / year	3.5%
Other	6,747	0.7%	0.6%	$7,143,822 / year	0.6%	$7,594,397 / year	0.7%	−$450,575 / year	−5.9%
All customers	1,029,955	100.0%	100.0%	$1,167,061,664 / year	100.0%	$1,167,061,664 / year	100.0%	$0 / year	0.0%

Table 22: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for PSEG-LI. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

RG&E's electric customers with heat pumps are subsidizing those who heat with fossil fuels by $13 million a year

Heating source	Customers	% of customers	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	15,578	4.4%	10.8%	$28,296,355 / year	8.6%	$14,723,603 / year	4.5%	$13,572,752 / year	92.2%
Electric resistance	36,755	10.5%	22.4%	$59,850,596 / year	18.3%	$34,399,369 / year	10.5%	$25,451,228 / year	74.0%
Natural gas	263,124	74.9%	58.1%	$208,812,716 / year	63.8%	$244,525,181 / year	74.7%	−$35,712,465 / year	−14.6%
Delivered fuels	26,531	7.5%	6.6%	$22,708,824 / year	6.9%	$24,701,767 / year	7.6%	−$1,992,942 / year	−8.1%
Other	9,493	2.7%	2.1%	$7,505,412 / year	2.3%	$8,823,985 / year	2.7%	−$1,318,572 / year	−14.9%
All customers	351,481	100.0%	100.0%	$327,173,904 / year	100.0%	$327,173,904 / year	100.0%	$0 / year	0.0%

Table 23: Total electric delivery revenue, electric delivery cost of service, and cross-subsidy by residential customer heating source subclass under the default rate, for RG&E. Assumes lump-sum (per-customer) residual allocation — equal residual share for all customers. Subclass cost-of-service calculated using NREL's CAIRO model.

BILL CHANGES

Utility-level versions of the statewide bill-change figures by heating fuel: Figure 15 (natural gas), Figure 16 (fuel oil and propane), and Figure 17 (electric resistance).

Natural gas

Central Hudson — How bills would change for natural gas heated homes after switching to heat pumps

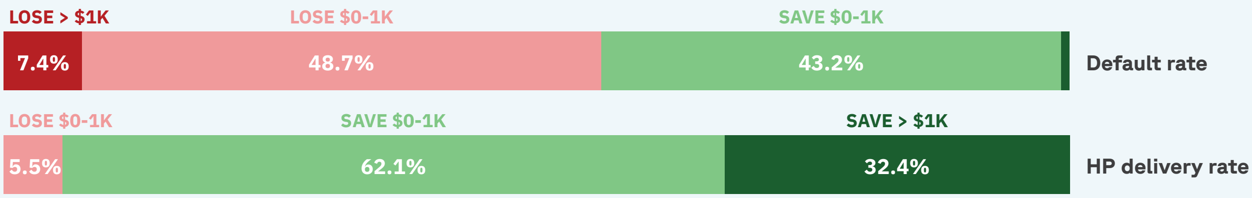


Figure 45: Change in total annual energy bills — Central Hudson natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

Con Edison — How bills would change for natural gas heated homes after switching to heat pumps

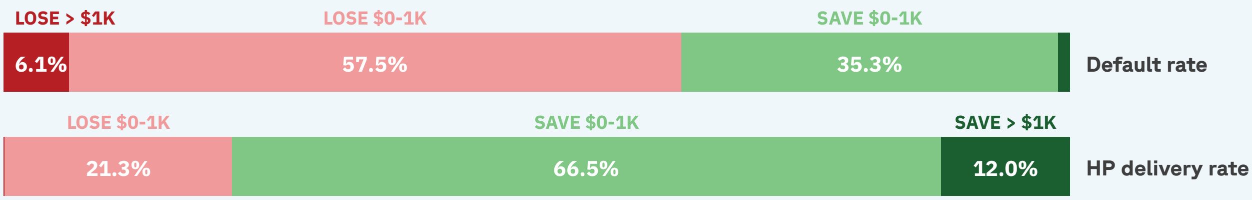


Figure 46: Change in total annual energy bills — Con Edison natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

National Grid — How bills would change for natural gas heated homes after switching to heat pumps

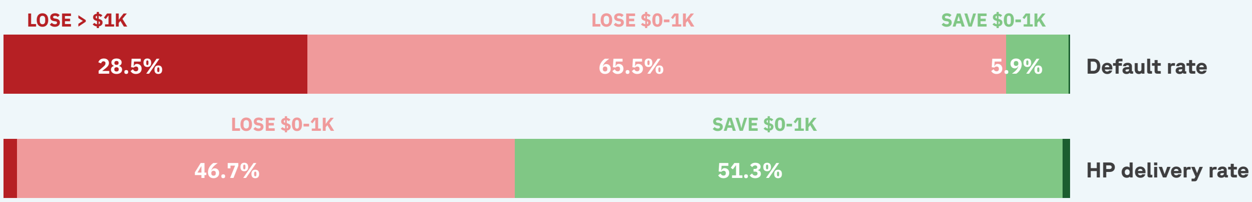


Figure 47: Change in total annual energy bills — National Grid natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

NYSEG — How bills would change for natural gas heated homes after switching to heat pumps

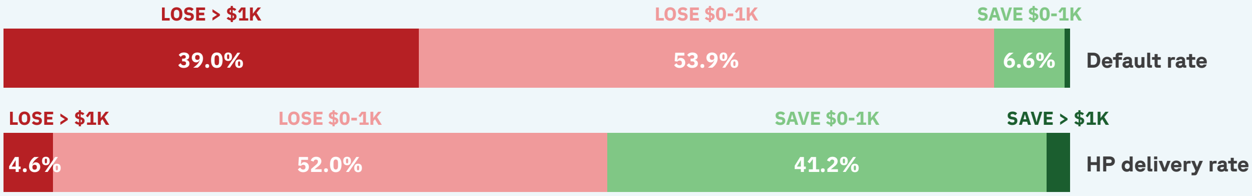


Figure 48: Change in total annual energy bills — NYSEG natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

O&R — How bills would change for natural gas heated homes after switching to heat pumps

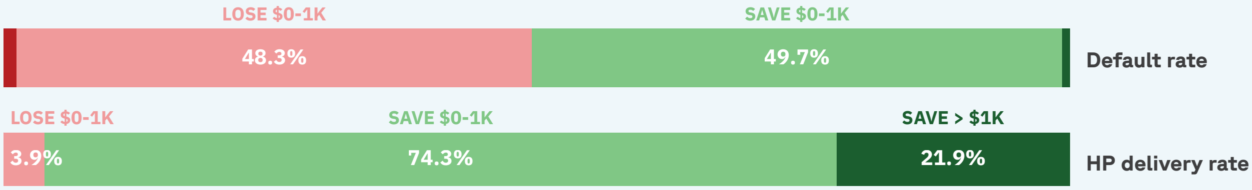


Figure 49: Change in total annual energy bills — O&R natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

PSEG-LI — How bills would change for natural gas heated homes after switching to heat pumps

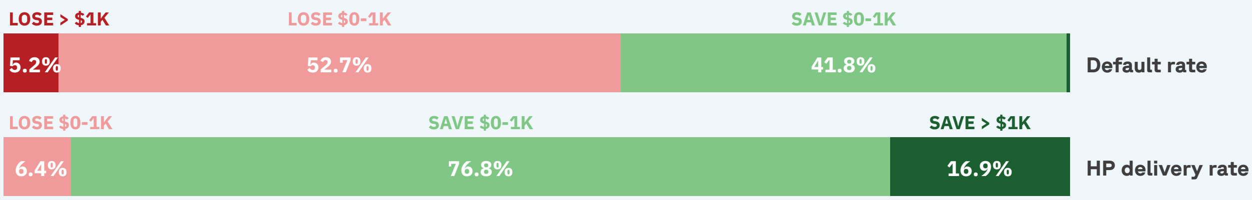


Figure 50: Change in total annual energy bills — PSEG-LI natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

RG&E — How bills would change for natural gas heated homes after switching to heat pumps

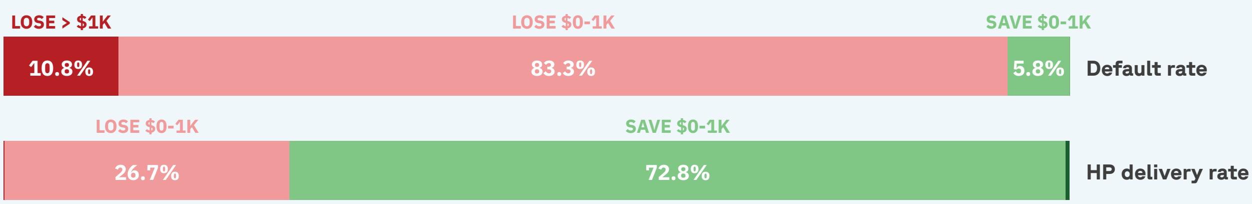


Figure 51: Change in total annual energy bills — RG&E natural gas homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in the utilities' energy affordability program before and after switching to a heat pump.

Fuel oil and propane

Central Hudson — How bills would change for fuel oil or propane heated homes after switching to heat pumps

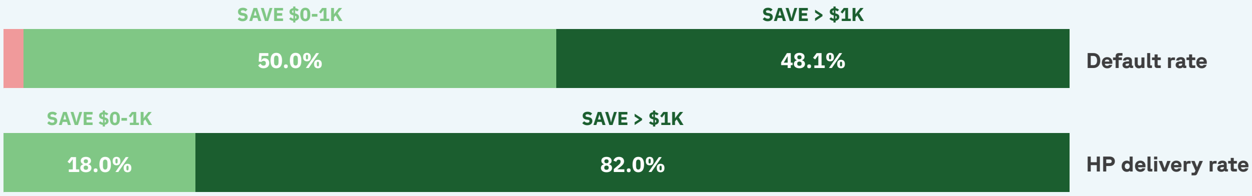


Figure 52: Change in total annual energy bills — Central Hudson oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

Con Edison — How bills would change for fuel oil or propane heated homes after switching to heat pumps

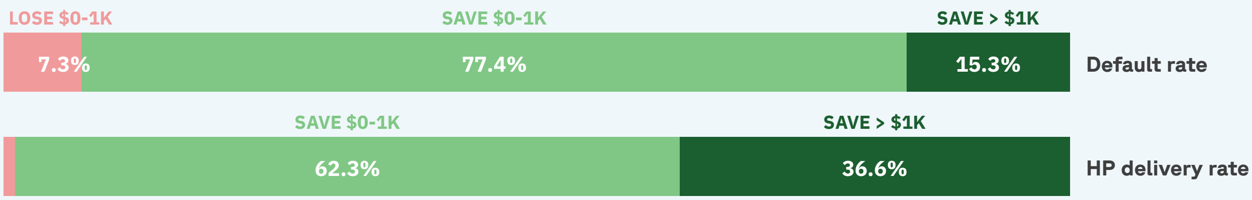


Figure 53: Change in total annual energy bills — Con Edison oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

National Grid — How bills would change for fuel oil or propane heated homes after switching to heat pumps

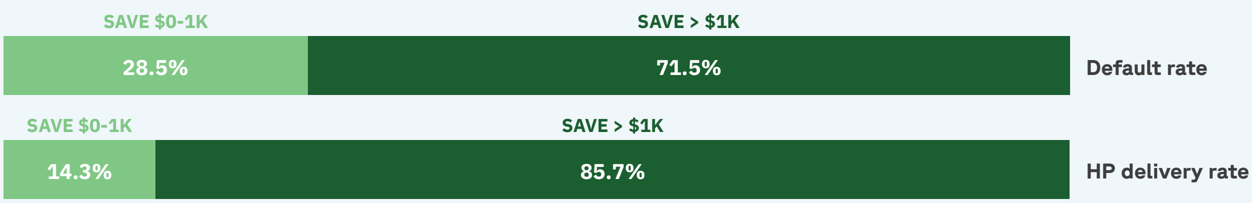


Figure 54: Change in total annual energy bills — National Grid oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

NYSEG — How bills would change for fuel oil or propane heated homes after switching to heat pumps

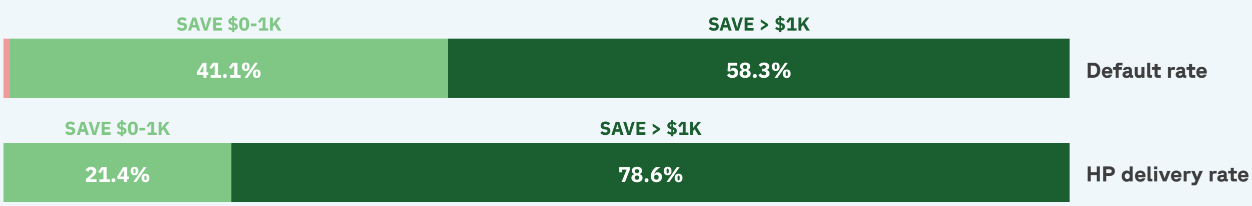


Figure 55: Change in total annual energy bills — NYSEG oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

O&R — How bills would change for fuel oil or propane heated homes after switching to heat pumps

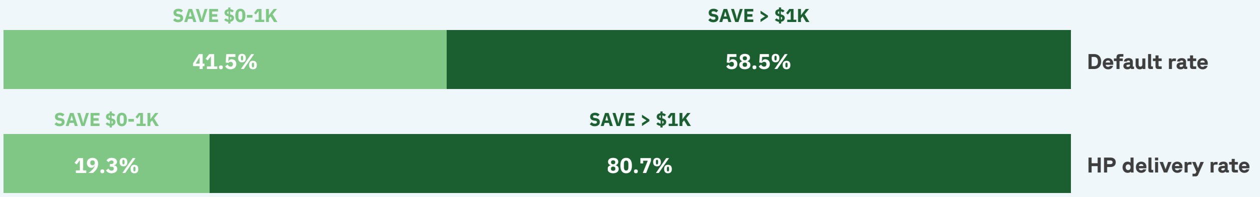


Figure 56: Change in total annual energy bills — O&R oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

PSEG-LI — How bills would change for fuel oil or propane heated homes after switching to heat pumps

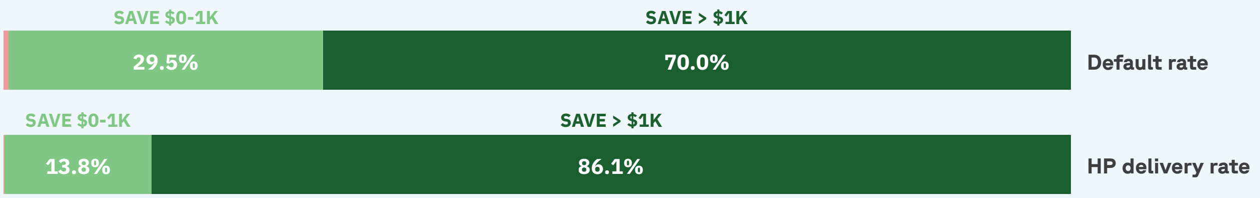


Figure 57: Change in total annual energy bills — PSEG-LI oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

RG&E — How bills would change for fuel oil or propane heated homes after switching to heat pumps

Figure 58: Change in total annual energy bills — RG&E oil/propane homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

Electric resistance

Central Hudson —How bills would change for electric resistance heated homes after switching to heat pumps

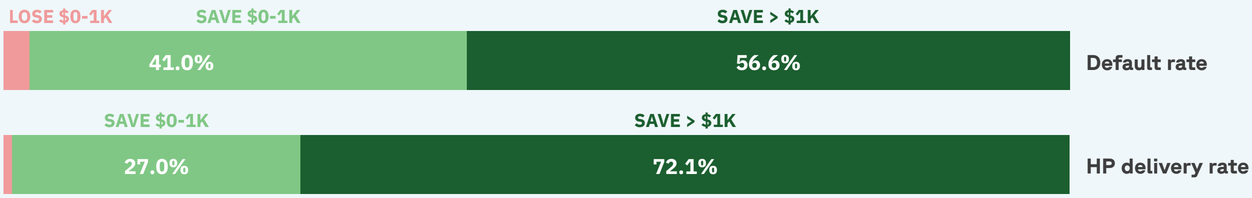


Figure 59: Change in total annual energy bills — Central Hudson electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

Con Edison —How bills would change for electric resistance heated homes after switching to heat pumps

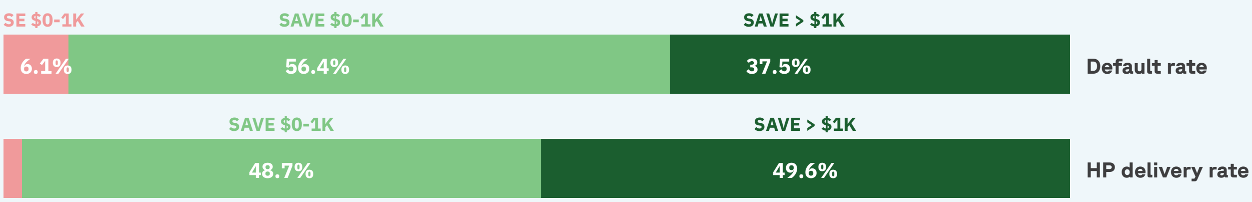


Figure 60: Change in total annual energy bills — Con Edison electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

National Grid —How bills would change for electric resistance heated homes after switching to heat pumps

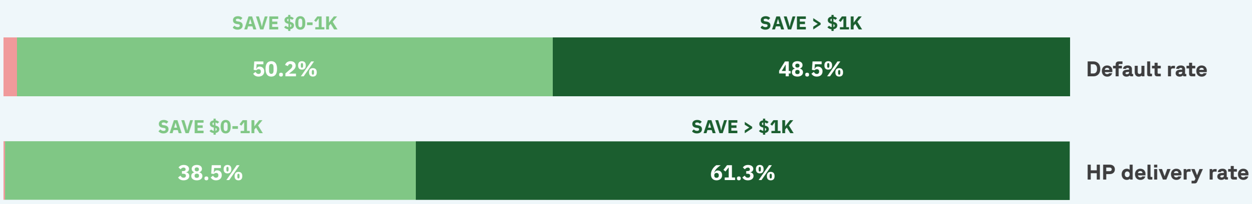


Figure 61: Change in total annual energy bills — National Grid electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

NYSEG —How bills would change for electric resistance heated homes after switching to heat pumps

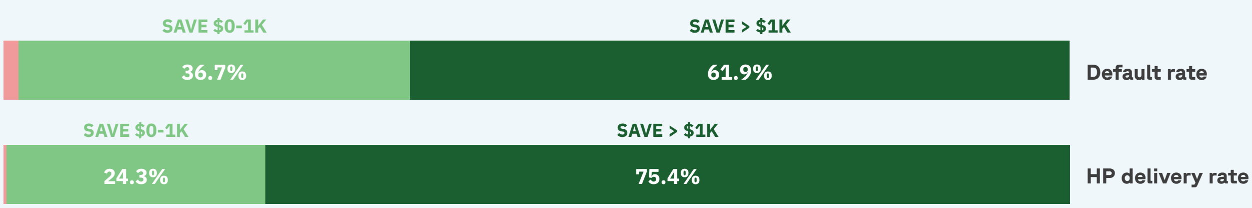


Figure 62: Change in total annual energy bills — NYSEG electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility

energy affordability programs before and after switching to a heat pump.

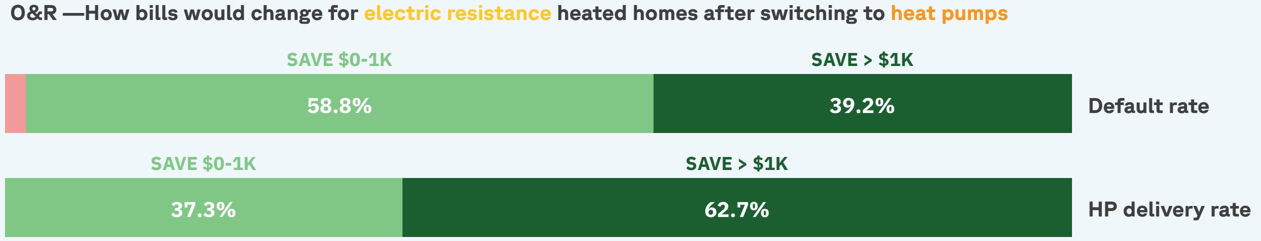


Figure 63: Change in total annual energy bills — O&R electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

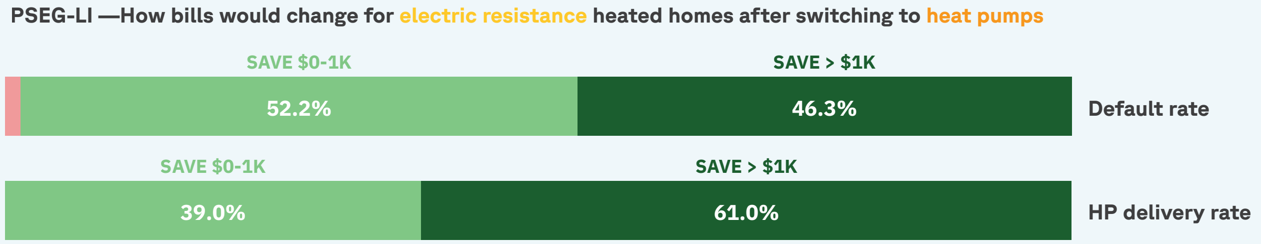


Figure 64: Change in total annual energy bills — PSEG-LI electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

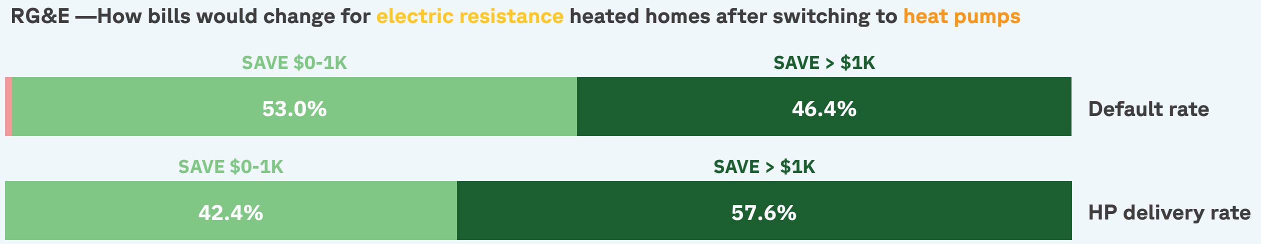
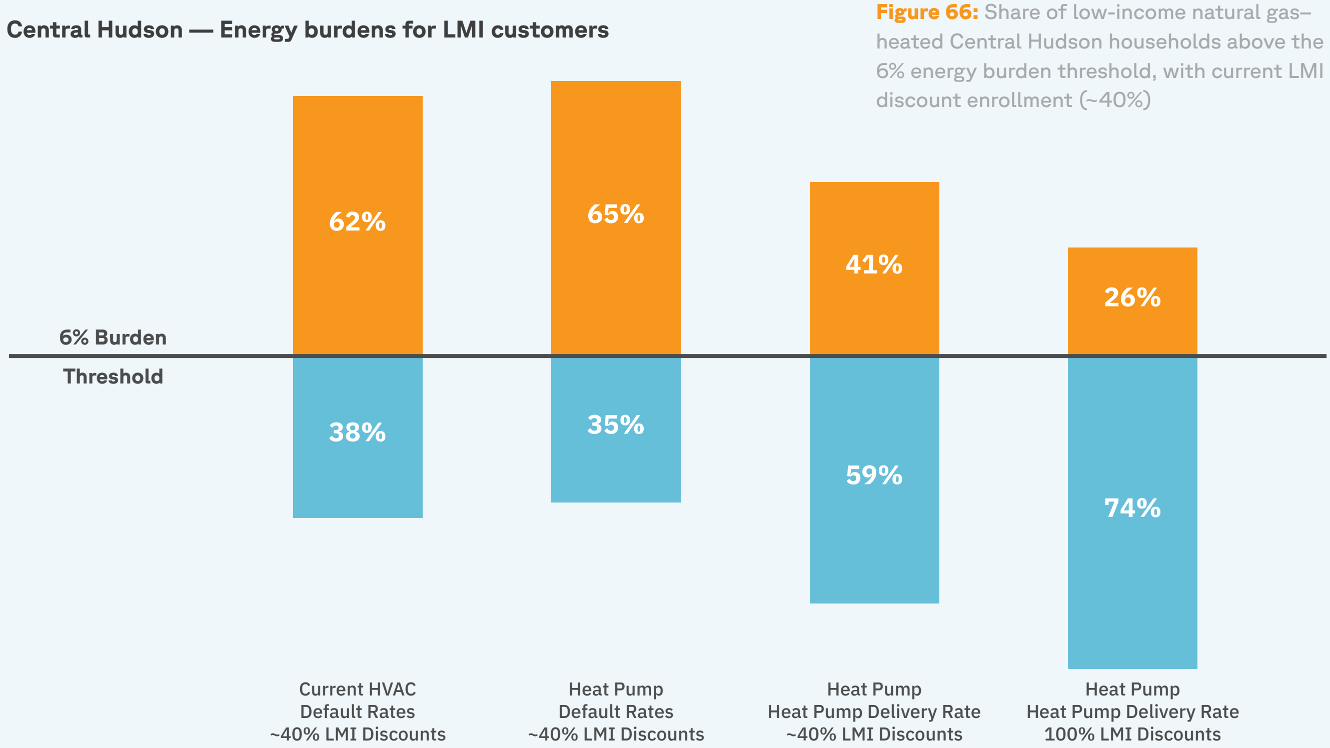


Figure 65: Change in total annual energy bills — RG&E electric resistance homes switching to a heat pump: default delivery rates vs. dedicated heat pump delivery rate. Assumes 40% of LMI households are enrolled in utility energy affordability programs before and after switching to a heat pump.

ENERGY BURDENS

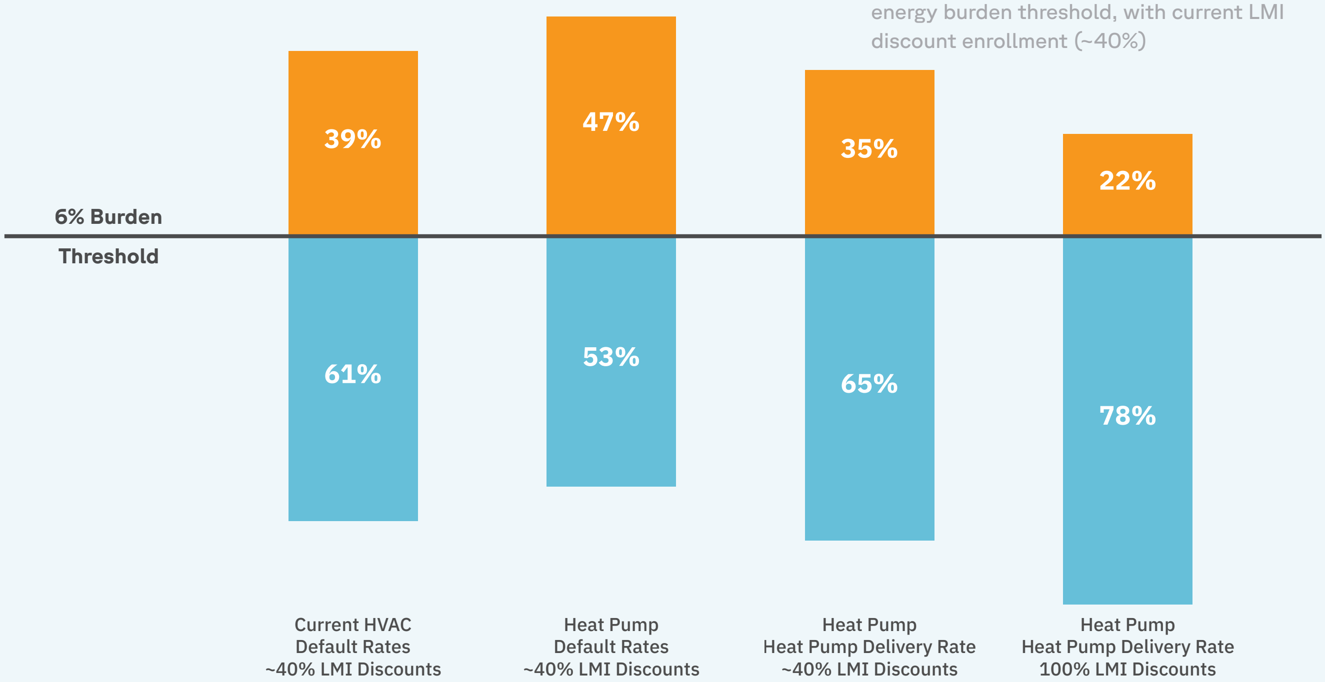
A utility-level version of the statewide energy burden chart in Figure 18, focused on low- and moderate-income households that currently heat with **natural gas**.

Figure 66: Share of low-income natural gas–heated Central Hudson households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)



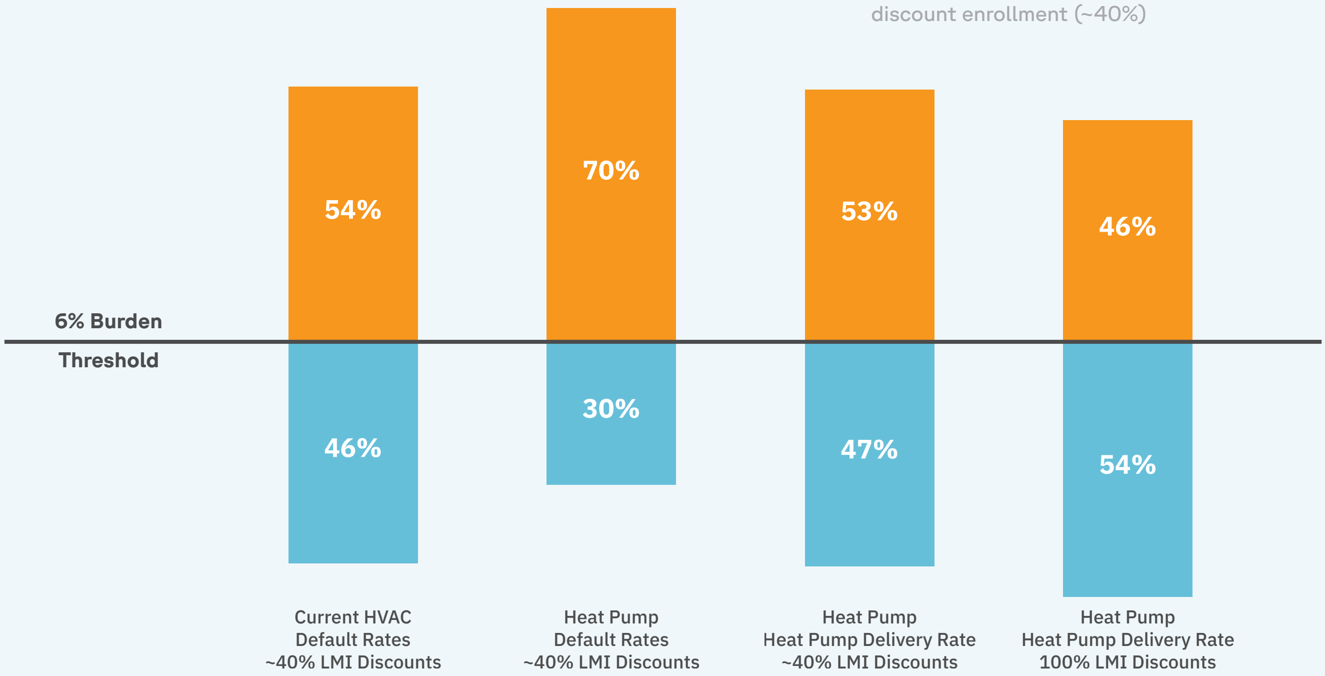
Con Edison — Energy burdens for LMI customers

Figure 67: Share of low-income natural gas–heated Con Edison households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)



National Grid — Energy burdens for LMI customers

Figure 68: Share of low-income natural gas–heated National Grid households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)



NYSEG — Energy burdens for LMI customers

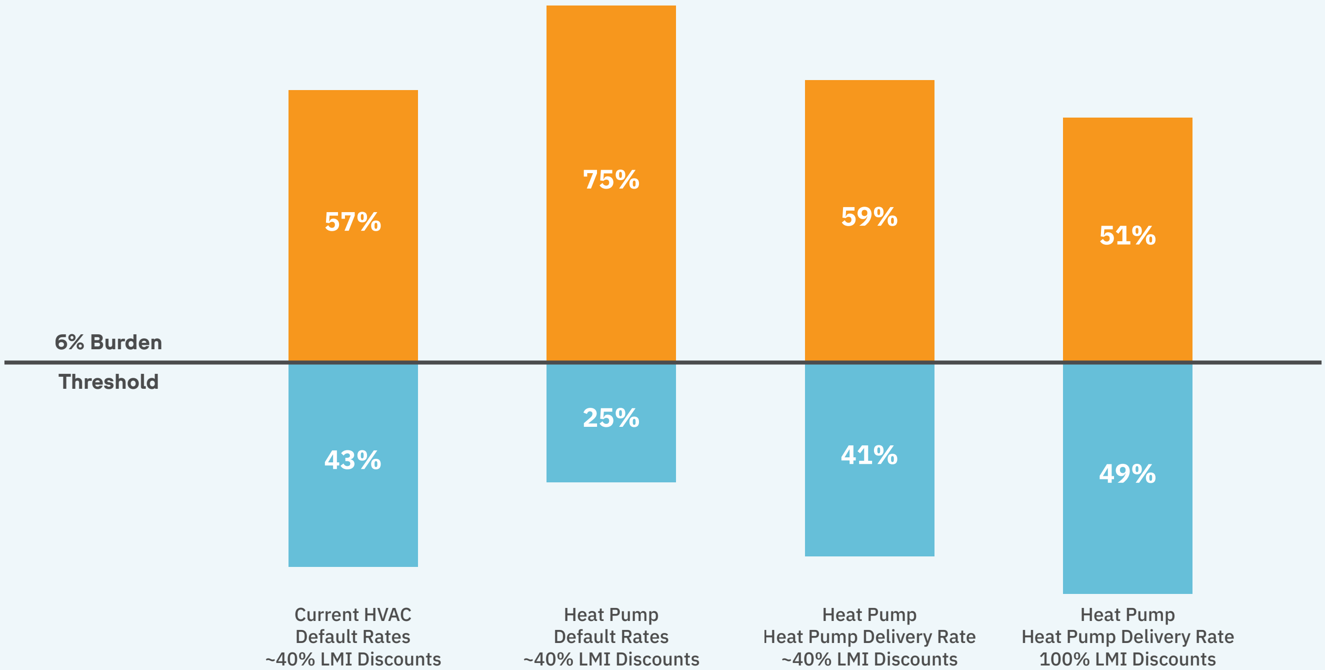


Figure 69: Share of low-income natural gas–heated NYSEG households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)

O&R — Energy burdens for LMI customers

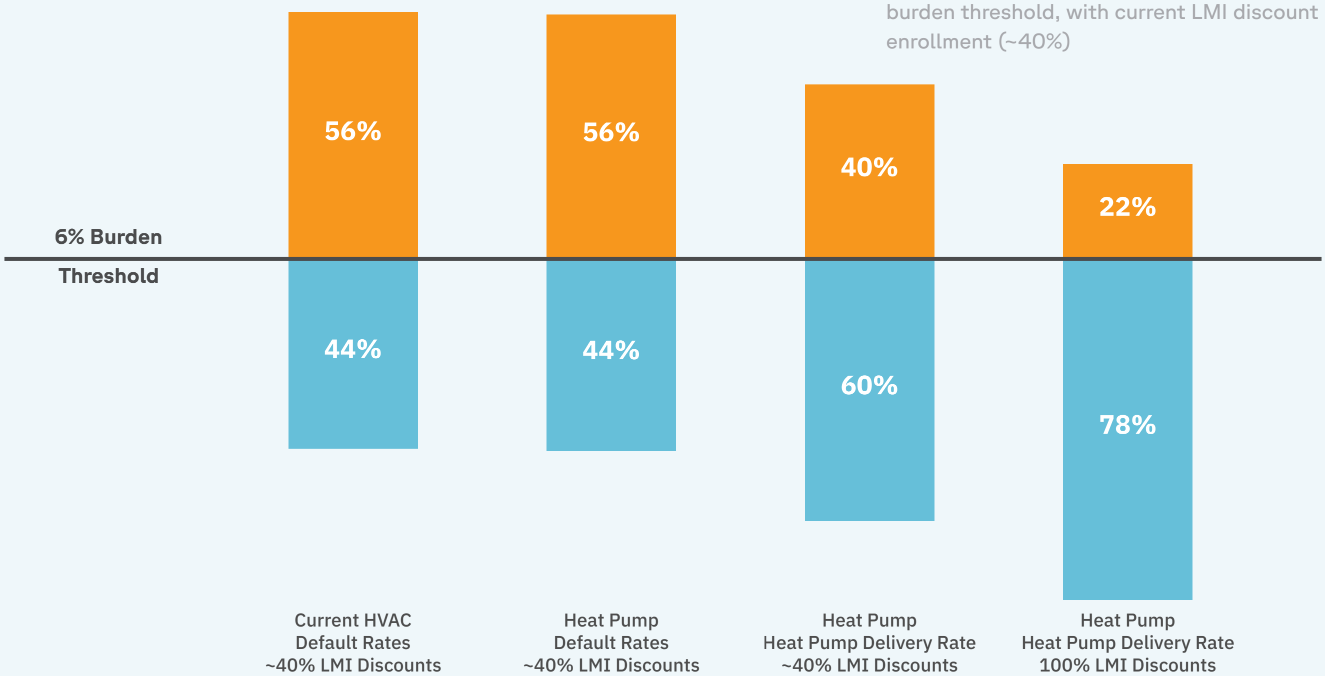
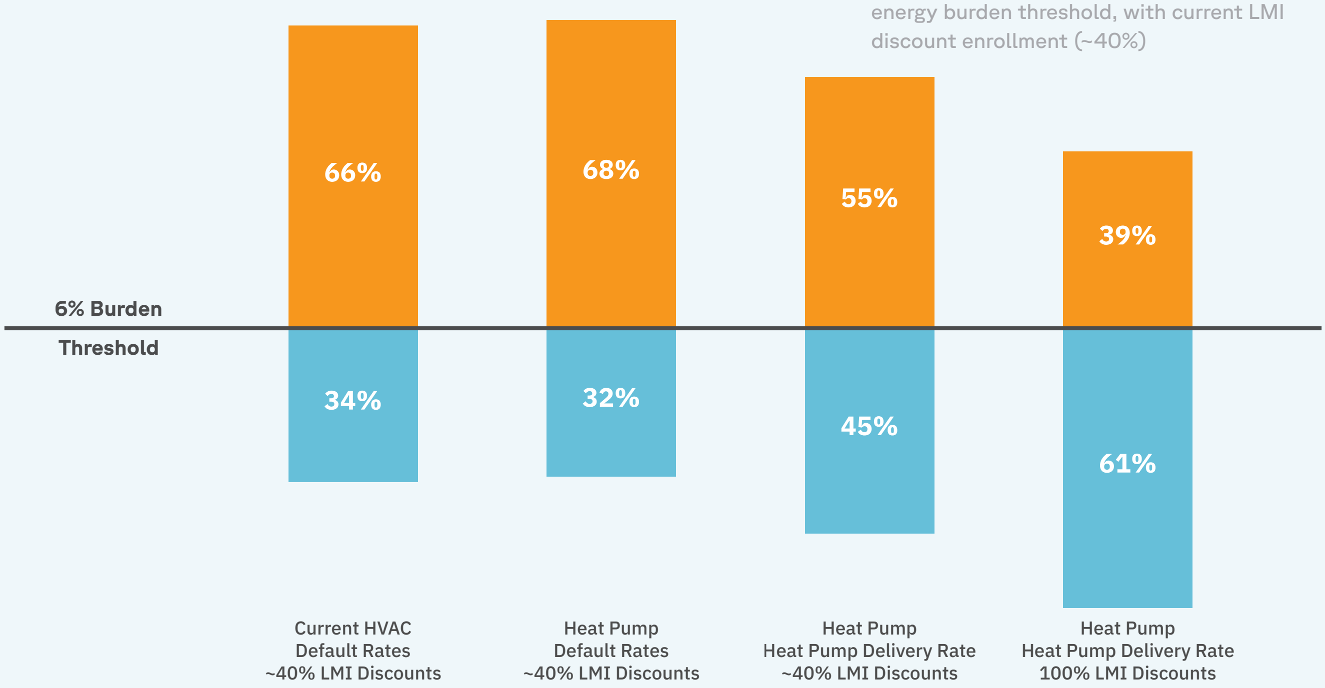


Figure 70: Share of low-income natural gas–heated O&R households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)

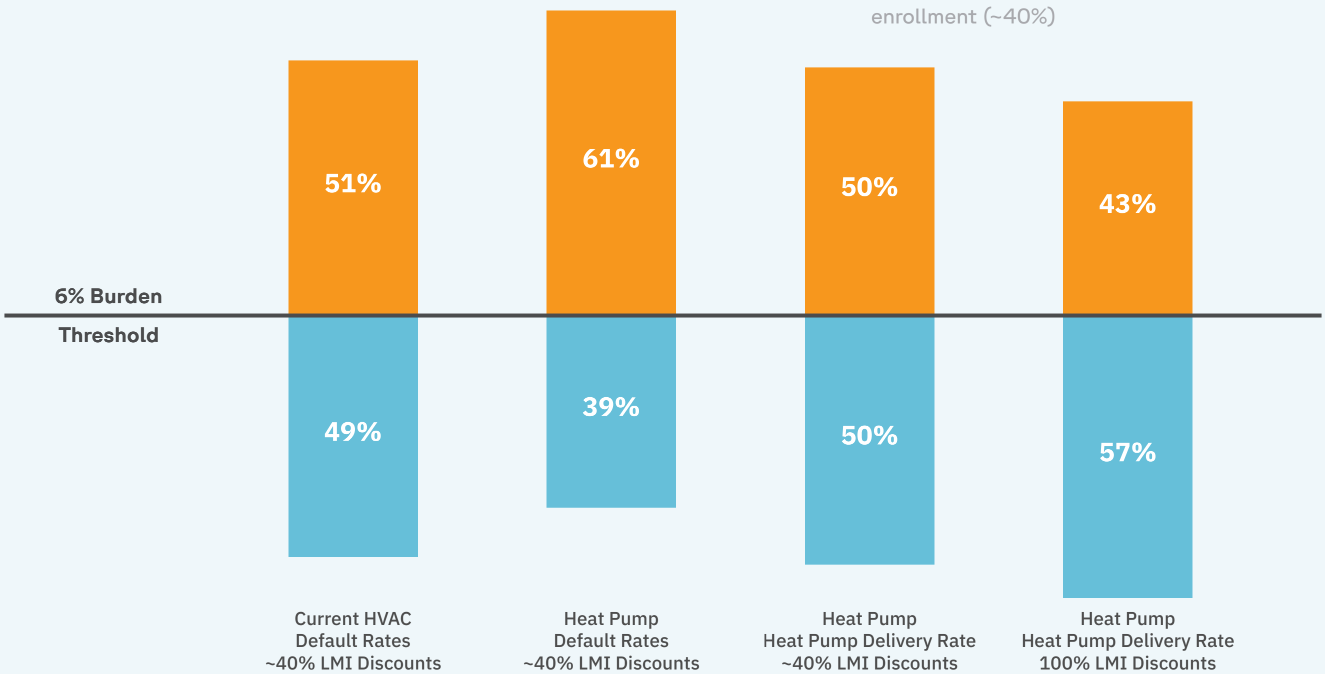
PSEG-LI — Energy burdens for LMI customers

Figure 71: Share of low-income natural gas–heated PSEG-LI households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)



RG&E — Energy burdens for LMI customers

Figure 72: Share of low-income natural gas–heated RG&E households above the 6% energy burden threshold, with current LMI discount enrollment (~40%)



PEAK GROWTH

A utility-level version of the statewide seasonal peak growth shown in Figure 38.

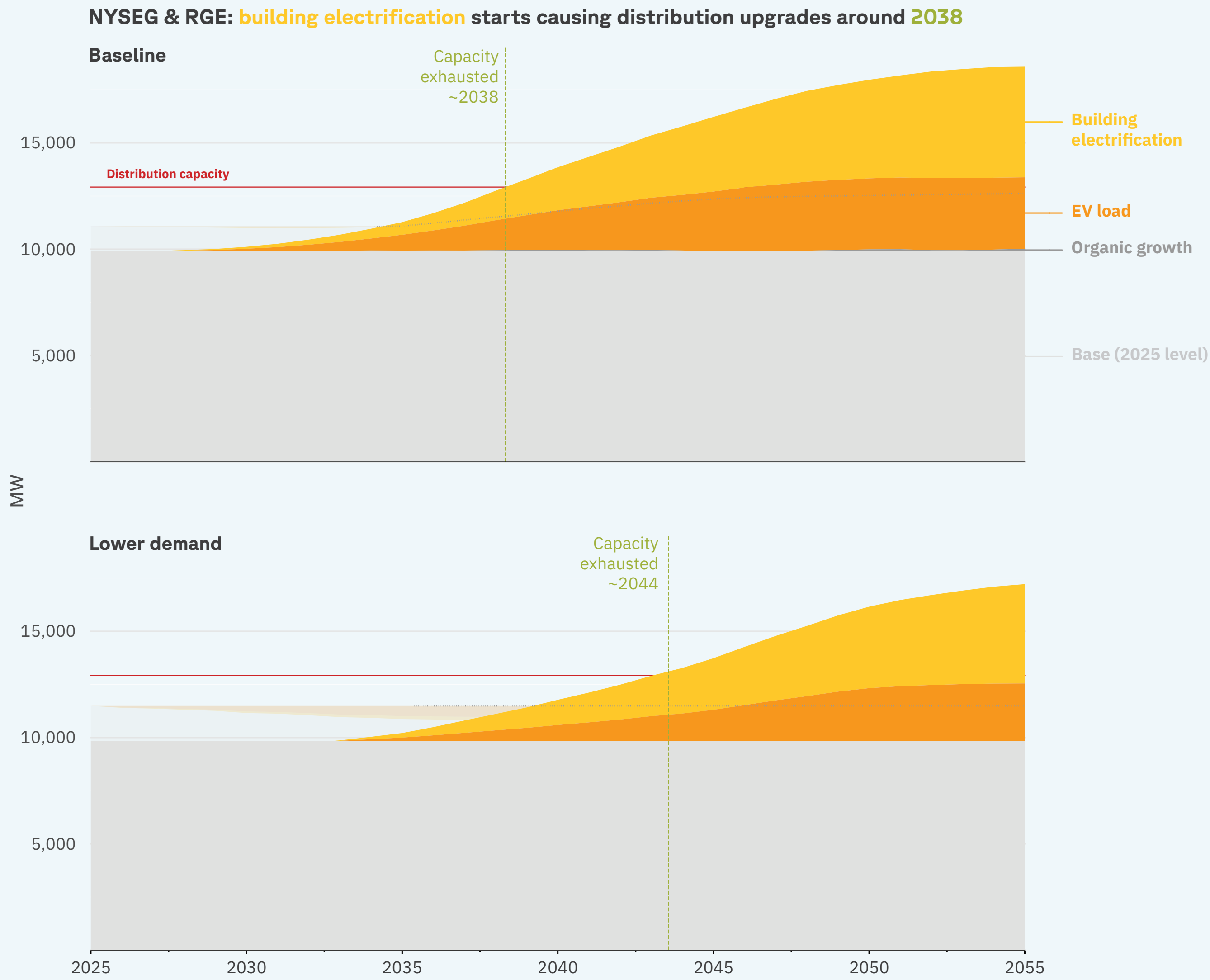


Figure 73: NYSEG & RGE summer (behind, translucent) and winter (in front, solid) coincident peak decomposed into growth components, excluding large loads. Top: baseline forecast. Bottom: lower demand forecast. Source: NYISO Gold Book 2025.

Figure 74: Central Hudson summer (behind, translucent) and winter (in front, solid) coincident peak decomposed into growth components, excluding large loads. Top: baseline forecast. Bottom: lower demand forecast. Source: NYISO Gold Book 2025.

Orange & Rockland: building electrification starts causing distribution upgrades only after 2039

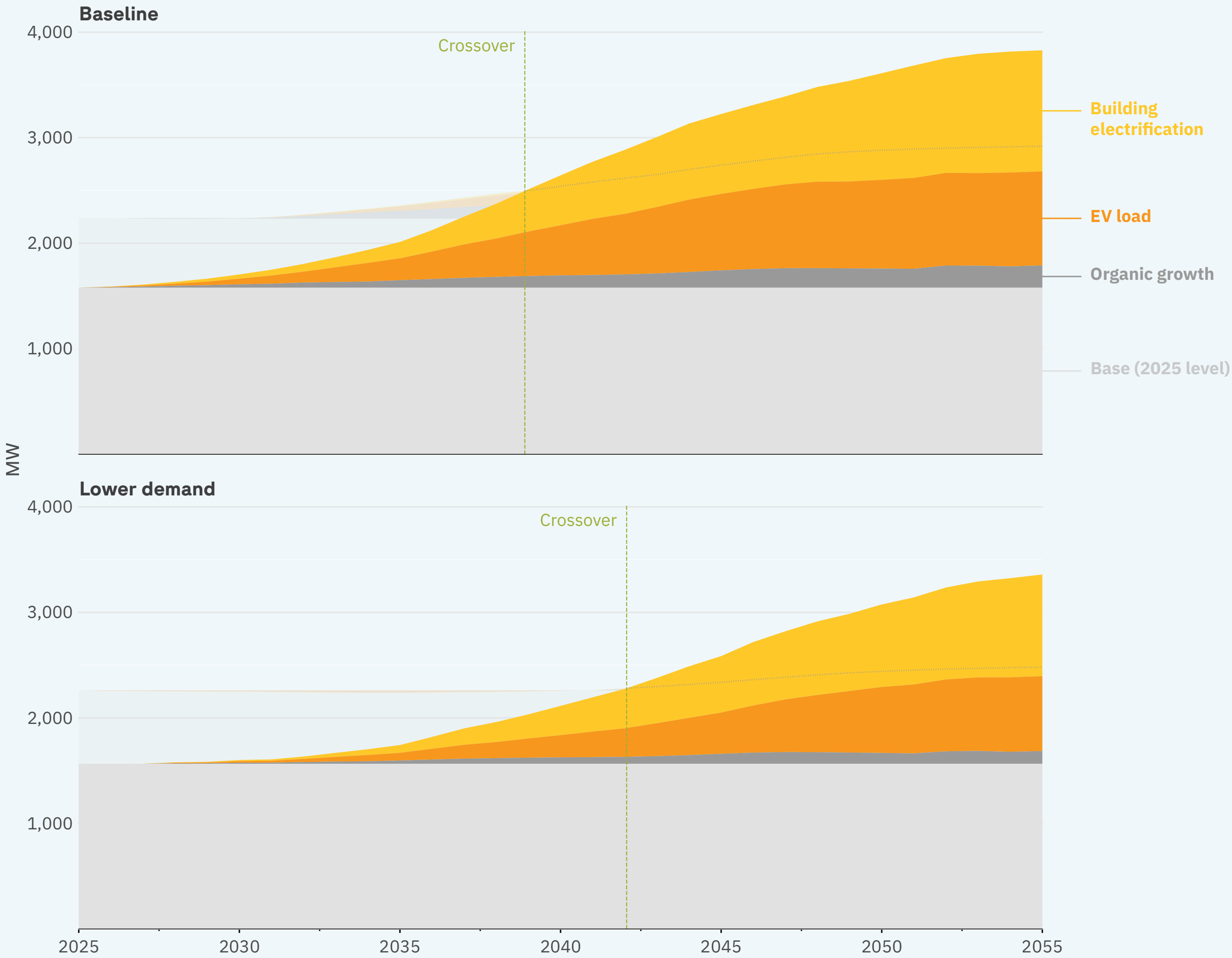


Figure 75: Orange & Rockland summer (behind, translucent) and winter (in front, solid) coincident peak decomposed into growth components, excluding large loads. Top: baseline forecast. Bottom: lower demand forecast. Source: NYISO Gold Book 2025.

Con Edison: building electrification starts causing distribution upgrades only after 2040

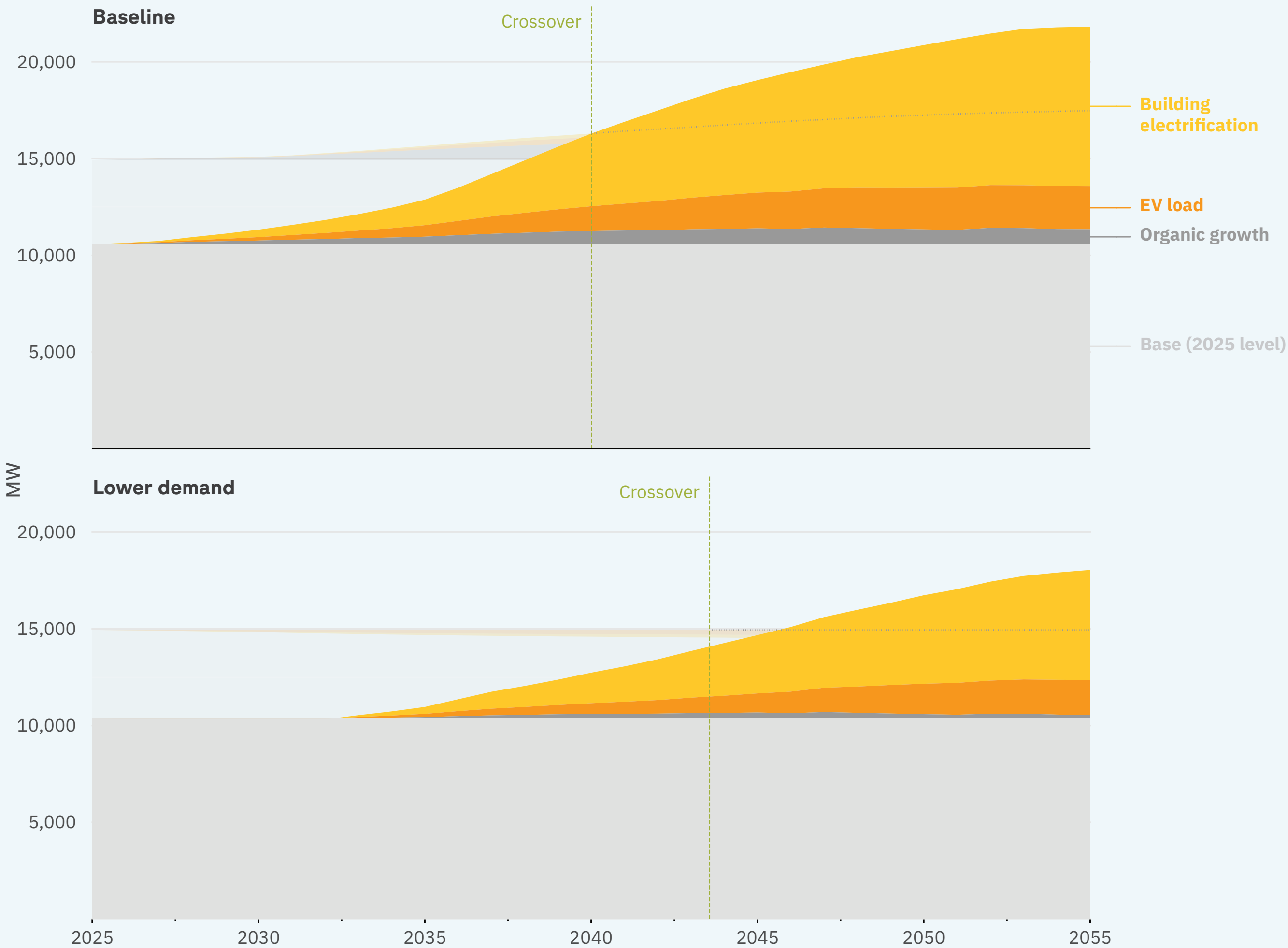


Figure 76: Con Edison summer (behind, translucent) and winter (in front, solid) coincident peak decomposed into growth components, excluding large loads. Top: baseline forecast. Bottom: lower demand forecast. Source: NYISO Gold Book 2025.

BILL ALIGNMENTS UNDER DEFAULT RATE

A utility-level view of the statewide overpayment patterns summarized in Table 3.

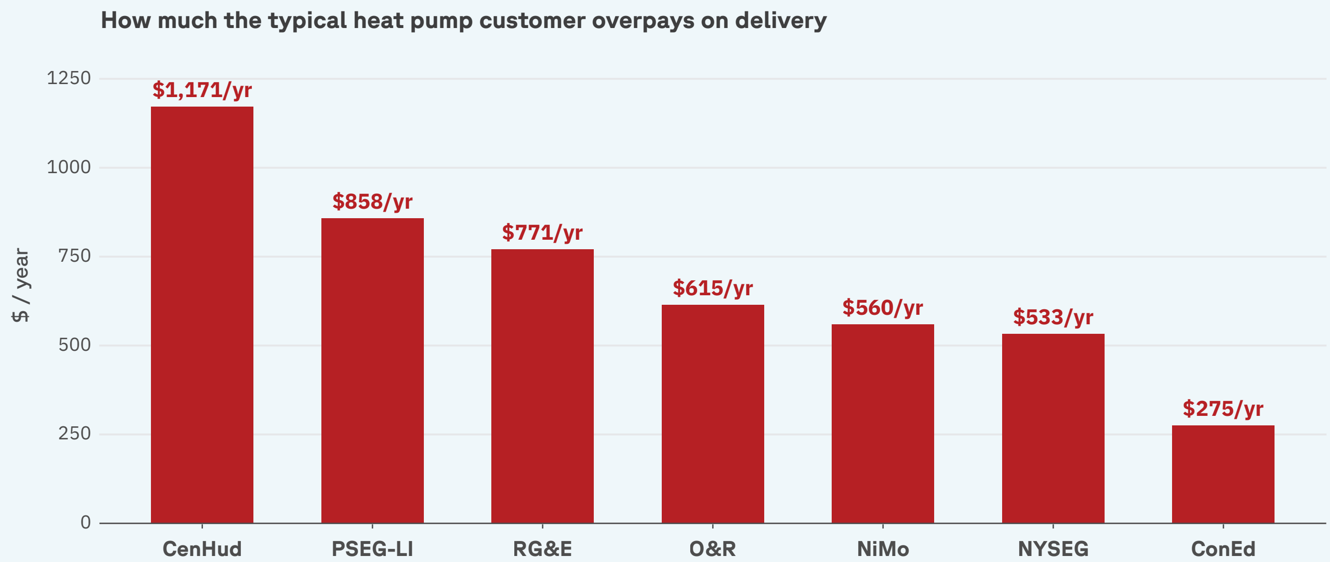


Figure 77: Delivery bill alignment for the typical (median-overpayment) heat pump customer, by utility territory. Values are the difference between the customer's annual electric delivery bill under the utility's default rate and their delivery cost of service, with positive values indicating overpayment. Cost of service calculated using NREL's CAIRO model and each utility's 2025 MCOS study (see methods).

MARGINAL T&D CAPACITY COSTS

Each utility has its own pattern of hourly Marginal T&D capacity costs — the hours when residential usage drives the need for the utility to upgrade its poles and wires. The heatmaps below show that pattern for each of New York's seven major utilities, hour by hour and month by month.

In each heatmap, the **left** panel shows marginal **bulk transmission** costs and the **right** panel shows marginal **sub-transmission and distribution** costs. The two panels use separate color scales so the seasonal and diurnal patterns in each are readable.

For where the underlying numbers come from — data sources, formulas, and links to the rate-design build scripts — see p. 115 and p. 116.

Central Hudson: Marginal transmission and distribution capacity costs ($/kWh, 2025)

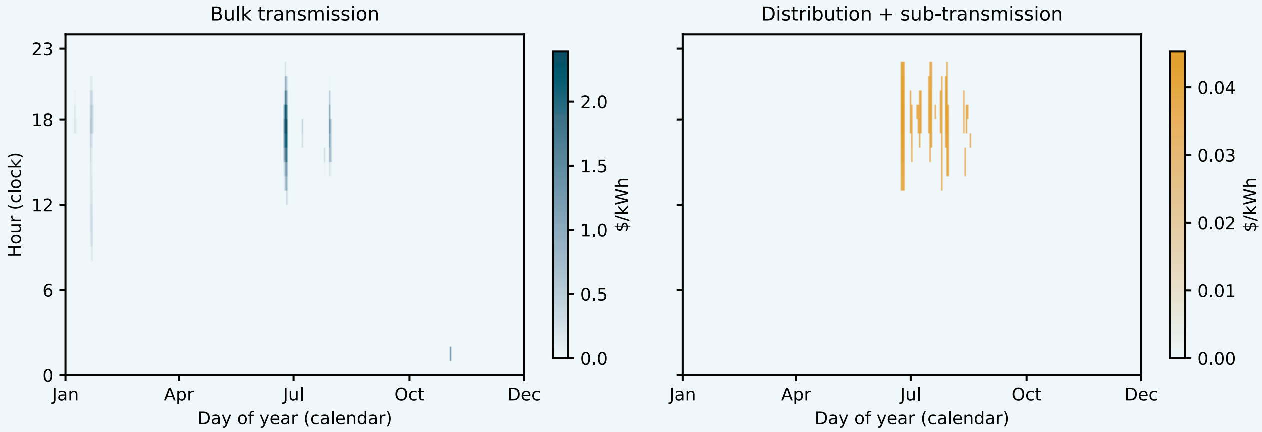


Figure 78: Marginal transmission and distribution capacity $/kWh by hour and day, Central Hudson.

ConEd: Marginal transmission and distribution capacity costs ($/kWh, 2025)

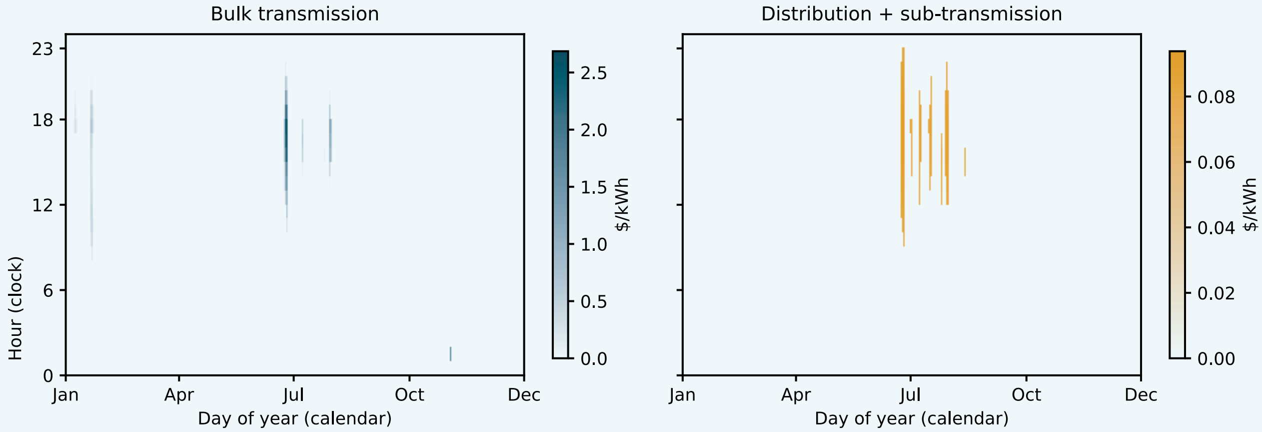


Figure 79: Marginal transmission and distribution capacity $/kWh by hour and day, ConEd.

National Grid: Marginal transmission and distribution capacity costs ($/kWh, 2025)

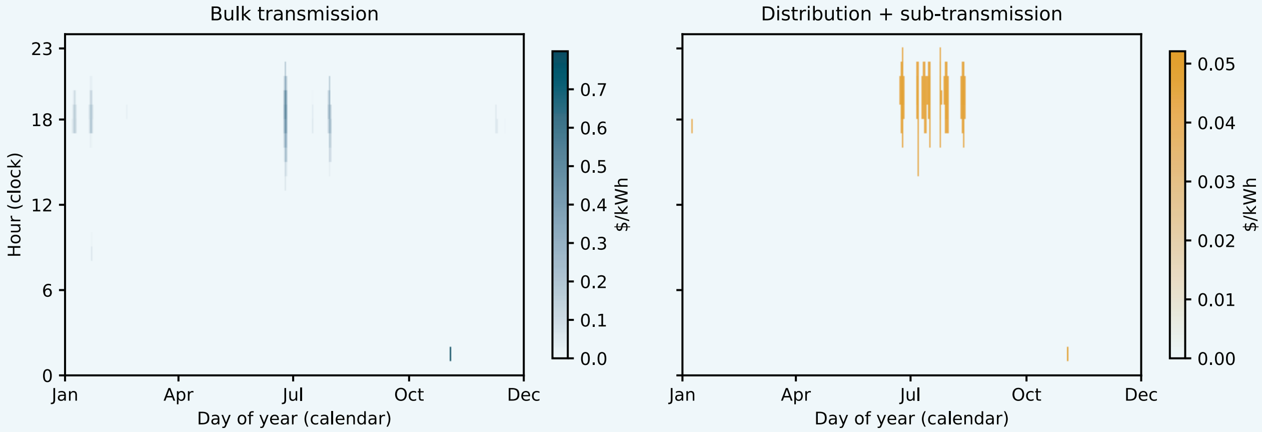


Figure 80: Marginal transmission and distribution capacity $/kWh by hour and day, National Grid (Northeast).

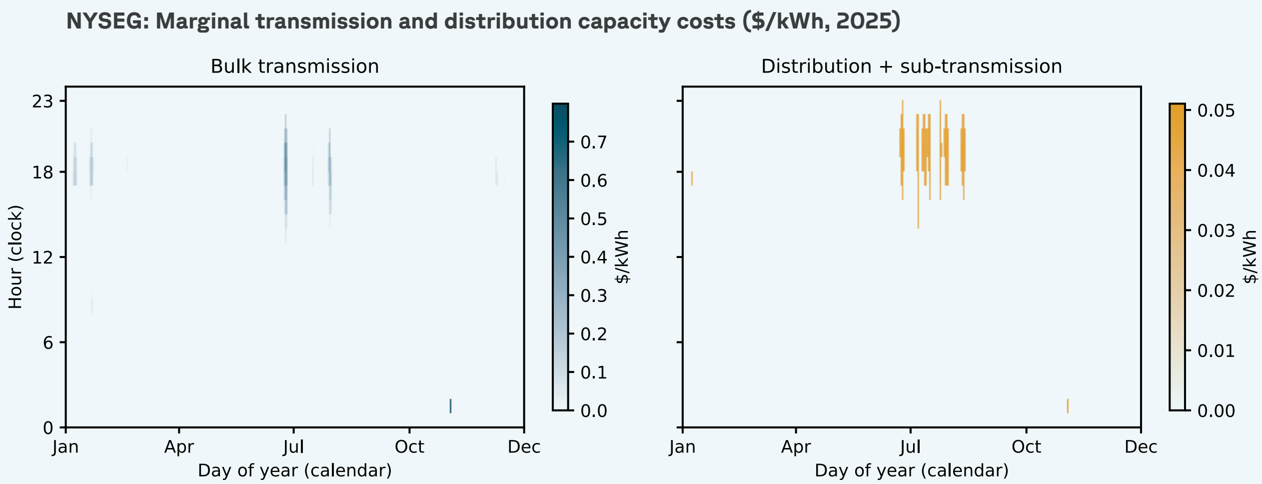


Figure 81: Marginal transmission and distribution capacity $/kWh by hour and day, NYSEG.

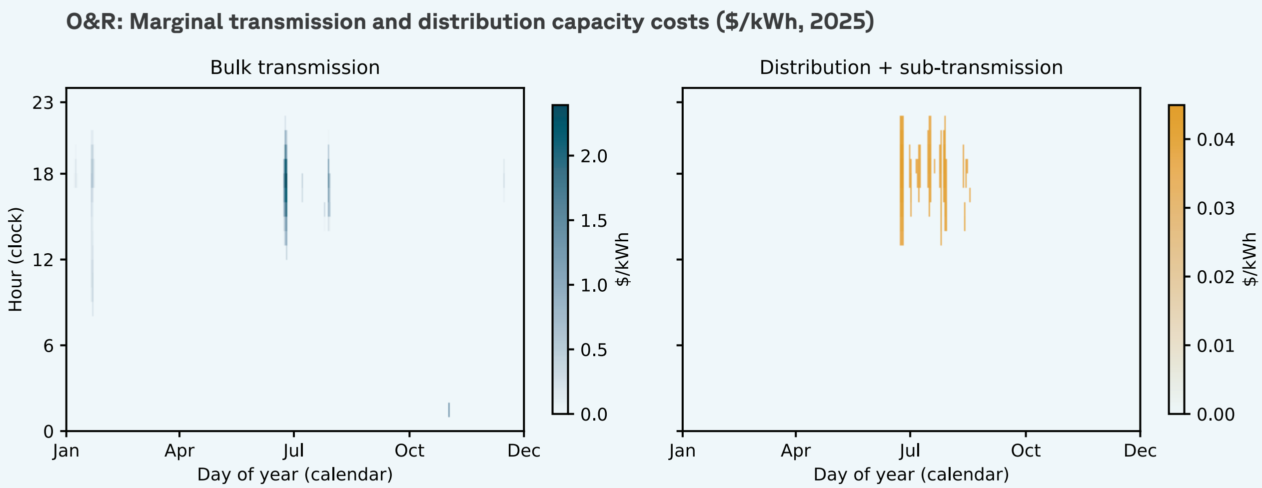


Figure 82: Marginal transmission and distribution capacity $/kWh by hour and day, Orange and Rockland.

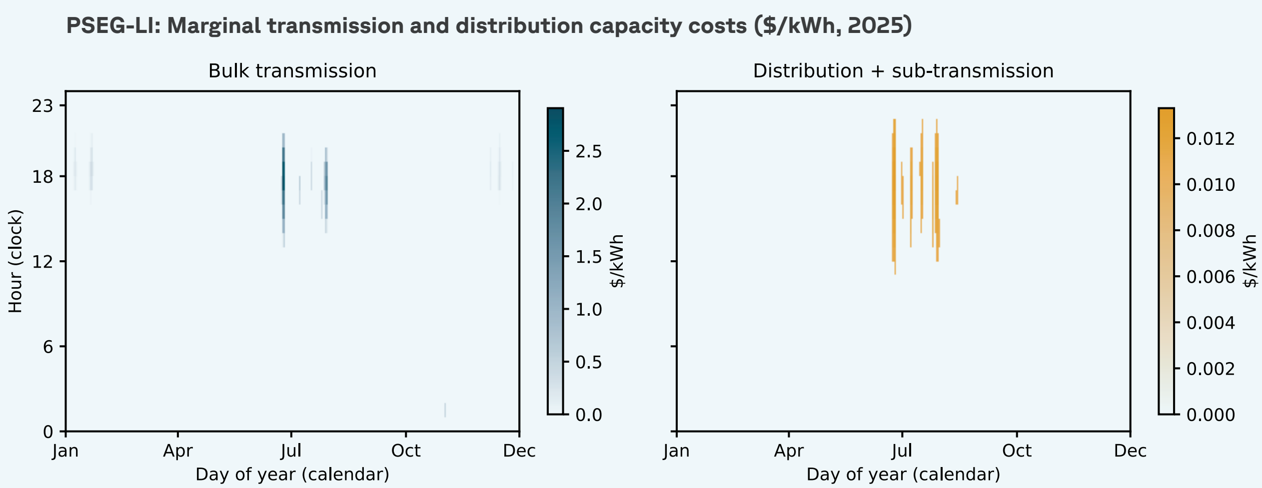


Figure 83: Marginal transmission and distribution capacity $/kWh by hour and day, PSEG Long Island.

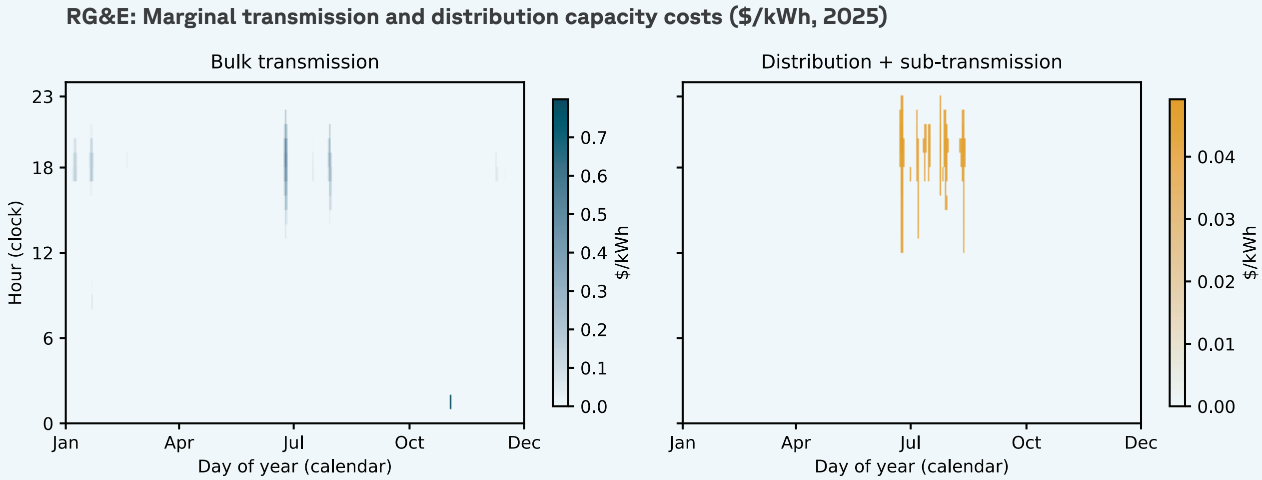


Figure 84: Marginal transmission and distribution capacity $/kWh by hour and day, Rochester Gas and Electric.

DEMAND-FLEX ELASTICITY

These are the raw per-utility, per-season elasticity parameters we used to model how heat pump customers shift electricity use from peak to off-peak hours under a TOU heat pump rate. They feed directly into the aggregated TOU bill-change results shown in Figure 33; see p. 129 for how we calibrate them to the Arcturus 2.0 meta-analysis.

Demand-flex elasticity calibration by utility and season — Calibrated to Arcturus 2.0 meta-analysis; savings are annual rate arbitrage per heat pump building.

	Price ratio	Elasticity (no tech)	Arcturus target (no tech, %)	Savings per heat pump (no tech, $)	Elasticity (with tech)	Arcturus target (with tech, %)	Savings per heat pump (with tech, $)
Central Hudson							
summer	3.05	−0.14	8.3	$16	−0.22	13.5	$24
winter	1.57	−0.12	4.0	$4	−0.18	6.1	$5
Con Edison							
summer	4.33	−0.12	10.6	$17	−0.18	17.4	$25
winter	1.98	−0.10	5.5	$4	−0.16	8.7	$6
NYSEG							
summer	2.93	−0.10	8.1	$5	−0.18	13.0	$8
winter	1.75	−0.10	4.7	$3	−0.16	7.3	$4
National Grid							
summer	2.91	−0.10	8.0	$4	−0.18	13.0	$7
winter	1.75	−0.10	4.7	$2	−0.16	7.3	$3
O&R							
summer	3.13	−0.14	8.5	$11	−0.24	13.8	$19
winter	1.57	−0.12	4.0	$3	−0.20	6.1	$4
PSEG-LI							
summer	3.80	−0.14	9.8	$19	−0.22	15.9	$30
winter	1.67	−0.12	4.4	$3	−0.18	6.8	$5
RG&E							
summer	2.87	−0.10	7.9	$4	−0.18	12.8	$6
winter	1.75	−0.10	4.7	$2	−0.16	7.3	$3

Table 24: Per-utility, per-season elasticity-of-substitution parameters used to model heat pump customer load shifting under a TOU heat pump rate. Each row reports the calibrated elasticity, the Arcturus 2.0 meta-analysis peak-reduction target it was calibrated to hit at the utility's peak-to-off-peak price ratio, and the resulting annual bill savings per heat pump building from rate arbitrage. Two variants are shown: 'no tech' (Arcturus' peak-reduction estimate for pilots without enabling technology) and 'with tech' (estimate for pilots with enabling technology, e.g., smart thermostats). See p. 129 for the calibration methodology.

Data and Methods

All modeling, bill calculation, and rate design was performed using Switchbox's open-source Rate Design Platform (RDP), built on top of NREL's CAIRO rate simulation engine.[66] The analysis notebooks that produced this report's figures and statistics are also open-source, in Switchbox's reports repository.

This section documents our methods. We first list the assumptions that underlie every number in the report. We then walk through how we answered its key quantitative questions: how we estimate a household's energy bills before and after a heat pump installation (p. 108); how we measure each customer's delivery cost of service and the resulting cross-subsidy between heat pump and non-heat-pump customers (p. 114); and how we designed the three proposed rates (p. 125).

Along the way, we document the supporting modeling choices that drive those headline numbers — how we simulate customer load shifting under time-of-use rates (p. 129), how we forecast peak demand growth as heat pump adoption scales (p. 132), how we apply New York's low-income discounts (p. 135), and how we derive each utility's sub-transmission and distribution marginal costs from recent marginal cost-of-service study (MCOSS) filings (p. 137).

NREL

66 NREL's Customer Affordability, Incentives, and Rates Optimization (CAIRO) Model provides users with a framework to evaluate the impact of different regulatory and utility decisions on ratepayers through a variety of evaluation metrics. (NREL 2026)

ASSUMPTIONS

- **Building stock.** We use NREL's ResStock 2024.2 with actual meteorological year 2018 (AMY 2018) weather data. The building stock sample is a statistical representation of New York's housing stock — not a census of actual homes. We weight to EIA-861 customer counts but do not correct for the kWh mismatch between ResStock and EIA (see p. 108).
- **Heat pump specification.** All heat pump retrofits use a single specification: high-efficiency cold-climate air-source heat pump (SEER1 20 / HSPF1 11), sized to maximum load, with electric backup. Ground-source heat pumps, ductless mini-splits, and partial electrification are out of scope.

- **HVAC only.** We model only space heating and cooling equipment replacements. Non-HVAC end uses (water heating, cooking, laundry) remain unchanged between baseline and heat pump scenarios. The upfront cost of heat pump installation is out of scope; we report only post-installation operating costs.
- **Static tariffs and fuel prices.** Electricity tariffs, natural gas tariffs, and delivered fuel prices are held constant at 2025 filed rates. We do not model future rate changes, fuel price volatility, or general inflation.
- **No behavioral response.** Outside the demand flexibility scenarios, we assume no change in how customers use energy after switching to heat pumps. Thermostat setpoints, occupancy patterns, and appliance usage are identical across baseline and heat pump scenarios.
- **Demand flexibility.** In the demand-flex scenarios, we model load shifting via a constant-elasticity substitution model calibrated to the Arcturus 2.0 with-tech meta-analysis (p. 129). The model applies uniform elasticities to all HP buildings — it does not capture heterogeneity in customer responsiveness. Energy conservation is enforced (total kWh is preserved).
- **Per-customer residual allocation (delivery).** We allocate the delivery residual on a per-customer basis — a normative choice that treats every residential customer as an equal beneficiary of the existing grid. Alternative allocation methods (EPMC, volumetric, Ramsey pricing) would produce different cross-subsidy estimates. Supply bills are held at default-tariff levels and do not require a residual allocation choice.
- **Marginal cost basis.** Sub-transmission and distribution marginal costs are derived from each utility's 2025 MCOS filing, using incremental diluted values levelized over 2026–2032 in real 2026 dollars. These represent near-term capital plans, not long-run equilibrium marginal costs. Bulk transmission uses OATT Attachment H annual revenue requirements as an upper-bound proxy. Energy and generation capacity marginal costs use 2024 NYISO LBMP and ICAP data.

- **Low-income discount structure.** We model New York's EAP/EEAP fixed monthly credits as of early 2026. Tier 4 (DSS referral) is excluded because it requires program enrollment data we cannot observe. Some EEAP (Tiers 5–7) credit amounts are unpublished for certain utilities and are treated as $0. Participation is modeled at two rates: ~40% (estimated current enrollment) and 100% (universal automatic enrollment).
- **Income data.** Household income comes from ResStock metadata (originally in 2019 dollars), inflated to 2025 dollars using the BLS CPI-U. Income is a modeled distribution, not observed tax data. Household size for FPL calculations comes from ResStock's occupant count.
- **Single weather year.** All results use AMY 2018 weather. A different weather year (particularly an extreme winter) would change absolute bill levels and could affect the relative economics of heat pumps. We do not perform weather-year sensitivity analysis.

HOW WE ESTIMATE ENERGY BILL CHANGES AFTER SWITCHING TO HEAT PUMPS

Building stock simulations

We use NREL's ResStock 2024.2 dataset to model New York's residential building stock. ResStock uses EnergyPlus physics-based simulations to represent the existing U.S. housing stock as a statistical sample, collectively matching the state's diversity of building types, sizes, ages, envelope characteristics, and heating equipment. These are simulated buildings, not individual real households. The 2024.2 release uses actual meteorological year 2018 (AMY 2018) weather data.[67]

New York has seven major electric utilities, each with its own tariff structure, service territory, and regulatory filings. We model all seven: Central Hudson (CenHud), Con Edison (ConEd), National Grid-Niagara Mohawk (NiMo), New York State Electric & Gas (NYSEG), Orange & Rockland (O&R), PSEG Long Island (PSEG-LI), and Rochester Gas & Electric (RG&E). Each ResStock building is assigned to an

ResStock

67 Default national sample weights represent ~252 real-world homes each. (NREL 2024). Single weather year was chosen to preserve weather driven coincident peaks which can be obscured in the composite weather models.

electric utility and, where applicable, a gas utility based on its geographic location. We rescale the ResStock sampling weights for each utility so that the weighted customer count matches the EIA-861 reported residential customer count as of 2024.[68]

ResStock outputs 15-minute end-use load profiles (electricity, gas, oil, propane) for each building; we aggregate to hourly resolution for bill calculation. We use two scenarios from this dataset:

- **Upgrade 0 (baseline)**: current HVAC equipment as distributed across the existing housing stock — natural gas furnaces, fuel oil boilers, propane heaters, electric resistance, or existing heat pumps.
- **Upgrade 2 (heat pump)**: high-efficiency cold-climate air-source heat pump retrofit with electric backup.[69] Performance is modeled hourly as a function of outdoor temperature via NEEP ccASHP performance curves.

Load curve adjustments. We apply two corrections to ResStock load curves before running the bill analysis.

Multifamily non-HVAC electricity correction. An analysis comparing ResStock residential loads to EIA-861 electricity sales (EIA 2026) across New York utilities revealed a systematic pattern: utilities with a higher share of multifamily buildings showed larger discrepancies between EIA-reported residential sales and the ResStock loads scaled to customer count. We traced the discrepancy to non-HVAC end uses (plug loads, lighting, appliances, and miscellaneous loads).

Multifamily buildings in ResStock had non-HVAC electricity intensity (kWh per square foot) roughly 1.5–2.0 times higher than single-family buildings, while HVAC intensity was actually about 40% lower for multifamily — directionally sensible since multifamily buildings have less exposed exterior surface area per dwelling unit.

We correct this by computing the mean non-HVAC electricity intensity (kWh/sqft, among buildings with non-zero consumption) for single-family and multifamily buildings separately, then dividing each multifamily building's non-HVAC end-use consumption by the multifamily-to-single-family ratio for that end use. Each end use gets its own ratio. **HVAC loads are**

68 We apply a uniform proportional rescaling to the ResStock building weights so that the weighted customer count matches the EIA-861 reported residential customer count as of 2024. This preserves the relative weighting across buildings while ensuring that utility-level totals aggregate correctly. Implemented in the RDP. (EIA 2026)

69 The heat pump is a high-efficiency cold-climate air-source heat pump with electric backup, rated SEER1 20 / HSPF1 11, sized to max load, with 90% capacity retention at 5°F (ResStock Measure Package 2).

left unchanged. The same scaling factors are applied to both annual totals and hourly load curves, preserving each building's hourly shape while reducing the non-HVAC magnitude.[66]

After customer reweighting and the multifamily correction, the total electricity consumption (kWh) implied by the ResStock loads does not perfectly match EIA-861 reported residential sales. Residual discrepancies remain — ResStock is above EIA for four utilities (Con Edison, RG&E, Central Hudson, NiMo) and below EIA for three (NYSEG, O&R, PSEG-LI), with magnitudes ranging from about 2% to 8%. We do not rescale the kWh to match EIA; the loads that enter the simulation are the ResStock hourly profiles, reweighted only for customer count. This means the simulation's calibrated delivery rates are somewhat lower (for utilities where ResStock exceeds EIA) or somewhat higher (for the rest) than the rates the utilities actually filed, since the same delivery revenue requirement is spread across a slightly different kWh denominator. The discrepancy does not affect relative comparisons between rate designs — the same kWh enters all scenarios — but it means the absolute $/kWh rates and dollar bill amounts are approximate rather than exact reproductions of filed rates.

70 Non-HVAC adjustment implemented in RDP. Each adjusted building is flagged to prevent double-application. Validation in the RDP.

Utility	% MF	Before	After
PSEG LI	19%	−4%	−6%
NYSEG	22%	+1%	−2%
CenHud	26%	+10%	+6%
RGE	29%	+12%	+7%
NiMo	30%	+9%	+4%
OR	30%	+2%	−3%
Con Edison	81%	+29%	+8%

ResStock – EIA % difference, before and after multifamily non-HVAC correction.

Non-HP multifamily HVAC approximation (upgrade 2 only). ResStock's upgrade 2 scenario converts most buildings to heat pumps, but a subset of large multifamily buildings (primarily 5+ unit, 8+ story) are left unconverted — their upgrade 2 load curves are identical to upgrade 0. To ensure these buildings are represented as HP customers in the upgrade 2 analysis, we approximate their HP load profiles using a k-nearest-neighbor method: for each unconverted multifamily building, we find the 15 buildings at the same weather station whose heating load curves are closest by root mean squared error (RMSE), then replace the target building's HVAC electricity, natural gas, fuel oil, and propane columns with the average of those neighbors' profiles. Metadata is updated to mark these buildings as heat pump customers.[71]

71 HVAC approximation implemented in RDP. Each approximated building is flagged.

Energy prices and tariffs

Electricity. Each of the seven utilities has its own residential electric tariff, consisting of a **delivery** portion (fixed monthly customer charge[72] plus volumetric rates set in the utility's

72 The fixed charge includes the customer charge and, for ConEd, NYSEG, O&R, and RG&E, a separate billing & payment processing charge. Some utilities' charges change mid-year; the table shows the annual average. PSEG-LI's customer charge is assessed daily ($0.54/day).

most recent rate case) and a **supply** portion (the utility's bundled commodity charge — Market Supply Charge, Power Supply Charge, or equivalent — which passes through NYISO wholesale energy costs to residential customers). Both delivery and supply rates were sourced from Genability's (Arcadia) utility rate database, classified into delivery and supply components, and verified against each utility's filed tariff schedules. Tariffs are committed in the RDP in standard URDB JSON format.[73]

Arcadia

73 Rates sourced from the Genability (Arcadia) utility rate database. Filed tariffs for all seven utilities are committed in the RDP. A detailed charge-by-charge taxonomy of every charge on each utility's residential bill — including which charges are included in the delivery revenue requirement and which are excluded — is documented as well.

Utility	Season	Fixed charge ($/mo)	Delivery (¢/kWh)	Supply (¢/kWh)
ConEd	Summer	21.28	17.14 (first 250) / 19.55	9.55
ConEd	Winter		17.20	10.18
NiMo	Monthly	17.89	8.1–9.4	7.0–11.6
NYSEG	Monthly	19.89	8.7–10.6	7.7–13.9
CenHud	Monthly	22	13.9–14.7	7.0–12.4
RG&E	Monthly	23.99	6.2–8.4	7.0–11.0
O&R	Summer	24.1	11.23 (first 250) / 13.84	10.56
O&R	Winter		11.33	9.33
PSEG-LI	Summer	16.43	11.0 off-peak / 21.8 on-peak	8.6 off-peak / 22.8 on-peak
PSEG-LI	Winter		9.5 off-peak / 18.6 on-peak	8.5 off-peak / 24.2 on-peak

Monthly: rates vary by calendar month; range shown. ConEd and O&R have increasing-block tiers with a 250 kWh/month threshold; '(first 250)' denotes the first-block rate. PSEG-LI has time-of-use rates; peak = weekday 3–7 PM, off-peak = all other hours and weekends.

Table 25: Default residential electric tariffs used in the simulation, per utility. Delivery includes the base rate-case delivery charge plus all volumetric surcharges topped up into the delivery revenue requirement. Supply includes the bundled commodity charge, MFC, and CES supply surcharge. Rates shown are pre-calibration values from filed tariff schedules.

Natural gas. Homes that heat with natural gas are assigned utility-specific residential heating tariffs. When a home installs a heat pump, it is moved from the heating rate to the corresponding non-heating rate (lower volumetric charges). Homes with zero gas consumption receive no gas tariff. Gas tariff data was sourced from RateAcuity and verified against utility filings.[74] ConEd, KEDLI, and KEDNY publish separate heating schedules for single-family and multifamily customers; the remaining utilities use the same schedule for both. CenHud, NFG, NiMo, O&R, and RG&E each have a single residential gas schedule that applies to all customers regardless of heating

RateAcuity

74 Rates sourced from the RateAcuity residential gas tariff database. Filed gas tariffs are committed in the RDP.

status or building type. NYSEG has separate heating and non-heating tariffs with identical volumetric rates but different fixed charges ($20.30 vs. $16.30). Volumetric rates vary by calendar month; the table shows the annual average of each tier's rate. The first tier (≤ 4 therms) is merged into the second for readability.

Gas utility	Heating (SF)		Heating (MF)		Non-heating	
	Fixed ($/mo)	Volumetric (per therm)	Fixed ($/mo)	Volumetric (per therm)	Fixed ($/mo)	Volumetric (per therm)
CenHud	$26.50	$2.08 first 50 therms $1.92 over 50 therms	$26.50	$2.08 first 50 therms $1.92 over 50 therms	$26.50	$2.08 first 50 therms $1.92 over 50 therms
ConEd	$33.03	$2.50 first 90 therms $2.20 next 2,910 therms $1.98 over 3,000 therms	$33.03	$2.39 first 90 therms $2.09 next 2,910 therms $1.88 over 3,000 therms	$34.96	$2.96/therm
KEDLI	$25.20	$2.62 first 50 therms $1.09 over 50 therms	$87.98	$1.33 first 1,000 therms $1.11 over 1,000 therms	$24.48	$3.63 first 50 therms $1.61 over 50 therms
KEDNY	$22.33	$2.67 first 50 therms $1.47 over 50 therms	$44.91	$1.34 first 1,000 therms $1.25 over 1,000 therms	$20.00	$5.15 first 50 therms $3.07 over 50 therms
NFG	$19.42	89¢ first 50 therms 57¢ over 50 therms	$19.42	89¢ first 50 therms 57¢ over 50 therms	$19.42	89¢ first 50 therms 57¢ over 50 therms
NiMo	$21.67	$1.17 first 50 therms 60¢ over 50 therms	$21.67	$1.17 first 50 therms 60¢ over 50 therms	$21.67	$1.17 first 50 therms 60¢ over 50 therms
NYSEG	$20.30	$1.29 first 50 therms 73¢ over 50 therms	$20.30	$1.29 first 50 therms 73¢ over 50 therms	$16.30	$1.29 first 50 therms 73¢ over 50 therms
O&R	$22.00	$1.67/therm	$22.00	$1.67/therm	$22.00	$1.67/therm
RG&E	$20.30	82¢ first 100 therms 80¢ next 400 therms 76¢ next 500 therms 57¢ over 1,000 therms	$20.30	82¢ first 100 therms 80¢ next 400 therms 76¢ next 500 therms 57¢ over 1,000 therms	$20.30	82¢ first 100 therms 80¢ next 400 therms 76¢ next 500 therms 57¢ over 1,000 therms

All gas tariffs use increasing-block tiers; volumetric rates and thresholds are converted from the underlying kWh-equivalent URDB JSON to therms. Rates shown are annual averages across monthly rate periods. CenHud, NFG, NiMo, O&R, and RG&E have a single residential schedule that applies to all customers; values are repeated across columns.

Table 26: Default residential gas tariffs used in the simulation, per gas utility. Single-tariff utilities apply the same rate to all residential customers.

Delivered fuels. For homes that heat with heating oil or propane, we use EIA's monthly residential fuel price series for New York, applied to each building's modeled annual consumption.[75]

Fuel	Monthly range ($/gal)	Annual avg ($/gal)
Heating oil	$3.68 – $4.30	$3.98
Propane	$3.21 – $3.40	$3.30

Source: EIA Form 877, 2024 weekly residential prices for New York, averaged to monthly. Prices are $/gallon excluding taxes.

Table 27: Residential delivered fuel prices used in the simulation (2024 monthly averages for New York).

75 EIA Form EIA-877, Petroleum Marketing Monthly — 2024 monthly residential heating oil and propane prices for New York. Available from the EIA Petroleum Marketing Monthly. (EIA 2024).

Assigning tariffs to buildings

Each ResStock building in the NY sample is assigned to an electric utility based on its geographic location using the RDP's utility assignment logic, which maps ResStock building locations to utility service territories.[76] Gas tariff assignment distinguishes heating from non-heating customers: homes with gas heating loads are assigned the utility's residential heating rate, while homes that use gas but not for space heating are assigned the non-heating rate. When a home switches to a heat pump, it moves from the gas heating rate to the non-heating rate.

76 Utility assignment implemented in RDP.

Computing bill changes under default rates

For each building, we apply the relevant tariffs to the building's hourly electricity load profile and annual fossil fuel consumption to calculate total annual energy bills.[77] The **bill change from switching to a heat pump** is the difference between a building's total annual energy bill (electricity plus gas, oil, and propane) under its current heating equipment and after a heat pump retrofit, both on today's default rates. A negative change means the household would save; a positive change means bills would rise.

77 Electric bills are computed by CAIRO. The RDP combines the delivery and supply portions; gas bills are computed independently by the RDP.

All bill comparisons include low-income discounts for 40 percent of eligible households for natural gas and electric bills. See p. 135. Results are computed building-by-building, aggregated using ResStock sample weights, and broken out by baseline heating fuel type (natural gas, oil/propane, electric resistance).

HOW WE MEASURE THE CROSS-SUBSIDY BETWEEN HP AND NON-HP CUSTOMERS

When we calculate the bills for each building under the default rates, we also compute their cost of service — what they *should* pay based on the cost they impose on the system. A customer whose bill exceeds their cost of service is overpaying (cross-subsidizing others); a customer whose bill falls short is underpaying (being cross-subsidized). We use this measure to inform the design of a fair rate that eliminates the cross-subsidy.

The cross-subsidization analysis uses the Bill Alignment Test (BAT), developed by researchers at NREL and Lawrence Berkeley National Lab (Simeone et al. 2023). The BAT compares what each customer pays in electric delivery charges against their delivery cost of service.

We operate the BAT at the **subclass level**: heat pump customers as one subclass, non-heat pump customers (fossil fuel and electric resistance) as the other. This lets us measure the total dollars flowing from one group to the other under a given rate structure, which serves as the basis to redistribute the **revenue requirement** between the subclasses (see p. 123 below).

cost of service

A customer's "fair share" of the utility's costs — the actual expense the utility incurs to serve that customer. It includes the cost of generating or purchasing electricity (supply), transmitting it over high-voltage lines, and distributing it over local poles and wires. Rate design aims to align what each customer pays (their bill) with their cost of service.

Bill Alignment Test

Framework (Simeone et al. 2023) that compares what each customer pays in delivery charges to their allocated cost of service. A positive BAT value means the customer is overpaying; a negative value means underpaying.

How we measure the cost of service for each customer

At the highest level, each customer's cost of service has two parts:

$$\text{Cost of Service}_i = \underbrace{\sum_{h=1}^{8760} L_{i,h} \times MC_h}_{\text{Marginal cost (economic burden)}} + \underbrace{f(i,R)}_{\text{Residual share}}$$

where:

- $i \in \mathcal{C}$ — customer index (over all customers)
- h — hour of the year (1–8760)
- $L_{i,h}$ — customer i's electricity load in hour h

- MC_h — system marginal cost in hour h
- R — total residual (the gap between the revenue requirement and total marginal cost revenue)
- $f(i, R)$ — customer i's allocated share of the residual

The marginal costs component (also called the economic burden) captures the incremental cost that a customer's hourly load pattern *causes* the system to incur — the cost of the next unit of generation, transmission, and distribution capacity needed to serve that load. The residual captures everything else in the utility's **revenue requirement** that marginal cost pricing does not recover — sunk costs such as carrying charges on past capital investments, operations and maintenance on existing assets, and the regulated return on the rate base.

marginal costs

The forward-looking cost of serving the next unit of electricity — the incremental cost of generation, transmission, and distribution capacity needed to meet one additional kWh or kW of demand. In other words, costs that change based on what customers do — specifically, the additional cost the system incurs when a customer consumes one more unit of electricity.

economic burden

A customer's total marginal cost of service — the sum of hourly marginal costs weighted by that customer's hourly consumption. Used in the Bill Alignment Test to measure what a customer "should" pay before residual allocation.

The next several subsections explain where each piece comes from: first the marginal costs, then the revenue requirement (delivery and residual) and how we allocate it.

Where the marginal costs come from

Our hourly marginal cost signal has four components, each derived from publicly available regulatory and market data:

Component	What it captures	Data source
Energy	Short-run cost of generation, congestion, and transmission losses in each hour. Contributes to the marginal cost of supply.	NYISO real-time locational marginal prices (LBMP)
Generation capacity	Cost of the next MW of generation to meet demand during scarcity hours. Contributes to the marginal cost of supply.	NYISO Installed Capacity (ICAP) market auction prices
Bulk transmission	Cost of the next MW of regional transmission capacity. Contributes to the marginal cost of delivery.	NYISO project-level transmission benefit studies (AC Primary, Addendum Optimizer variants, Addendum MMU, LI Export, NiMo MCOS bulk-TX entry) aggregated via constraint-group cumulative-secant derivation
Sub-TX + distribution	Cost of the next MW of local delivery capacity. Contributes to the marginal cost of delivery.	Utility-specific 2025 Marginal Cost of Service (MCOS) studies (PSC Docket 19-E-0283)

How marginal costs are assigned to individual customers

Each component produces a separate 8,760-hour signal. The signals differ in which hours carry non-zero costs. The capacity and transmission components use **exceedance weighting** to concentrate costs in peak hours — the hours when the grid is closest to its capacity limits and new load is most likely to trigger infrastructure investment. Both exceedance weighting and the probability-of-peak method (used below for distribution) serve as proxies for the probability that a given hour is capacity-binding.

Given the top N hours by load, each hour's exceedance and weight are:

$$e_h = \max(L_h - T,\ 0), \qquad w_h = \frac{e_h}{\sum_{h'} e_{h'}}$$

where:

- L_h — aggregate system load in hour h for the relevant load zone (specified separately for each component below)
- T — load threshold: the load of the hour immediately below the N-th highest
- e_h — exceedance of hour h above the threshold (zero for hours outside the top N)
- w_h — normalized weight assigned to hour h (zero outside the top N)

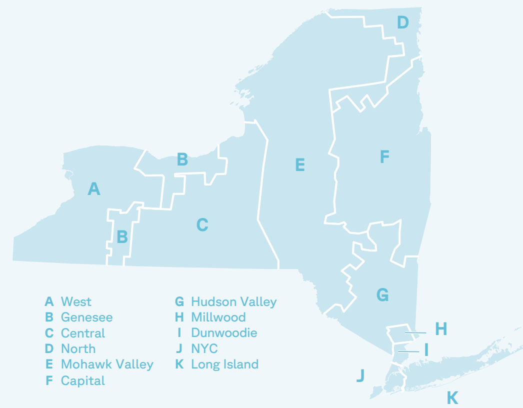
This pattern recurs below for generation capacity, applied to locality-specific load profiles and monthly ICAP prices. Bulk transmission uses a related but distinct allocation scheme based on seasonal System Capability Resource (SCR) windows; see below.

Energy. Every hour receives a numeric value equal to the NYISO real-time locational marginal price for the utility's zone(s) — real-time LBMPs can be zero or negative, and the pipeline applies no filtering or flooring:[78]

$$MC_h^{\text{energy}} = \text{LBMP}_h$$

For single-zone utilities, we use that zone's hourly LBMP directly. For multi-zone utilities, we compute a load-weighted

New York ISO
Independent System Operator



Utility	LBMP zone(s)
RG&E	B
CenHud	G
O&R	G
Con Edison	G, H, I, J
NYSEG	A–F
NiMo	A–F
PSEG-LI	K

NY utility to NYISO LBMP zone mapping. Single-zone utilities use the zone's LBMP directly; multi-zone utilities use a load-weighted average across their zones.

78 NYISO real-time 5-minute LBMPs aggregated to hourly arithmetic means per zone (NYISO 2024b); multi-zone utilities are blended via the load-weighted formula above. Output is normalized to the CAIRO 8,760-hour calendar (December 31 dropped in leap years) with small gaps linearly interpolated. No transmission-loss gross-up and no inflation adjustment are applied. Hourly energy MC signals are built by the RDP.

average where the zonal load shares come from NYISO zone-level hourly demand mapped to utility territories.

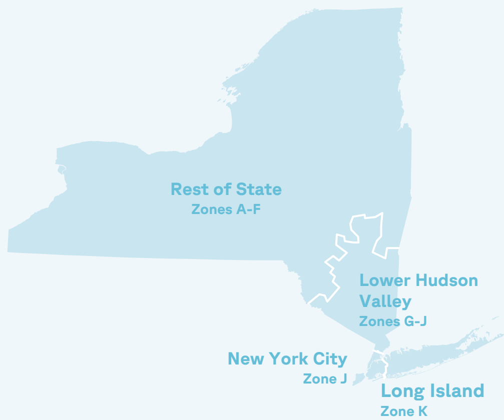
$$\text{LBMP}_h = \sum_z (\text{LBMP}_{z,h} \times L_{z,h}) / \sum_z L_{z,h}$$

where:

- z — NYISO pricing zone within the utility's territory
- $\text{LBMP}_{z,h}$ — real-time locational marginal price in zone z during hour h ($/MWh)
- $L_{z,h}$ — hourly demand in zone z during hour h (MW), from NYISO zone-level data mapped to utility territories

Generation capacity. NYISO operates an Installed Capacity (ICAP) market with monthly spot auctions. Unlike ISO-NE's single forward auction, NYISO prices capacity by **locality** — geographic zones with different levels of transmission constraint. Four auction localities clear at different prices:

- **Rest of State** (ROS, NYCA-priced) — the ROS capacity obligation covers zones A–F, but peak hours are identified from the full statewide load, zones A–K
- **Lower Hudson Valley** (LHV, auction locality G–J, inclusive of NYC)
- **New York City** (NYC, zone J)
- **Long Island** (LI, zone K)



Downstate utilities pay higher capacity prices because their constrained transmission paths require local generation. Only Spot auction clearing prices are ingested; Strip and Monthly auctions are excluded. Published ICAP $/kW-month prices are used directly, with no Unforced Capacity (UCAP) derating applied.

For each auction locality, the pipeline identifies the top 8 hours per month by aggregate load across that locality's *nested* zone footprint, then allocates the monthly ICAP auction price across those hours using exceedance weights:[79]

$$MC_h^{\text{gen cap}} = \sum_m w_{h,m} \times P_m^{\text{ICAP}} \times c_w$$

79 NYISO ICAP monthly Spot auction clearing prices by locality (NYISO 2024a). Auction-locality-to-nested-footprint mappings and utility capacity-obligation weights are sourced from the NYISO ICAP Manual (Table 7-5) (NYISO 2026a) via the RDP. Hourly capacity MC signals are built in the RDP.

where:

- $w_{h,m}$ — exceedance weight for hour h in month m (from the formula above, applied to the nested locality's aggregate load, top 8 hours per month)
- P_m^{ICAP} — ICAP auction clearing price for month m in the applicable locality ($/kW-month)
- c_w — capacity weight: the utility's share of its capacity obligation in each locality (e.g. Con Edison: 0.87 NYC + 0.13 LHV, from Table 7-5 of the NYISO ICAP Manual)

For the NYCA-priced (Rest-of-State) component, the nested-locality load used to identify peak hours is the full NYISO statewide aggregate (all 11 zones, A–K); the NYCA ICAP partition itself, however, represents A–F capacity. For the GHIJ-priced component, the nested footprint is zones G–J. Multi-locality utilities (Con Edison) sum separate component signals: each component's monthly price is scaled by the utility's locality capacity weight, then allocated to that nested locality's top-8 peak hours. At most $8 \times 12 = 96$ component-hour allocations are assigned per locality; a two-locality utility such as Con Edison has up to 192 allocations, but fewer distinct clock hours if its two localities' top-8 hours overlap.

Bulk transmission. Bulk-TX marginal costs capture the incremental cost of regional transmission infrastructure (roughly 115 kV and above). Rather than levelizing a single utility-filed revenue requirement, the RDP derives a per-locality $/kW-yr cost from NYISO's own project-level public-policy and competitive-solicitation transmission studies, then allocates it to hourly peaks using an 80-hour seasonal window. The pipeline has five stages:

1. **Inputs.** Project-level NYISO Public Policy Transmission Planning and Competitive System Planning Process (CSPP) benefit studies, together with the NiMo MCOS bulk-TX entry, are collected as pipeline inputs. Seven input scenarios — AC Primary, the two Addendum Optimizer variants (Existing Localities and G-J Elimination), the two Addendum MMU variants (Baseline and CES+Retirement, merged), LI Export (Policy), and NiMo MCOS (Bulk TX) — map to six distinct constraint groups.[80]

80 Project-level inputs trace back to NYISO Public Policy Transmission Planning and Competitive System Planning Process (CSPP) benefit studies, plus the NiMo MCOS bulk-TX entry (NYISO 2018, 2019, 2023). Constraint-group $/kW-yr values are computed by the RDP. Hourly allocation to the 80-hour SCR window with two-level weighting is implemented in the RDP; the per-utility blend is assembled by the RDP. See the RDP for end-to-end pipeline documentation.

2. **Derivation.** For each constraint group, the derivation script computes a $/kW-yr value via a cumulative-secant aggregation over its member projects.
3. **Paying-locality aggregation.** Each constraint group is mapped to one or more paying localities (ROS, LHV, NYC, LI) via the nested-locality scheme in the derivation script; per-paying-locality costs are averaged within group.
4. **Hourly allocation.** For each utility, the allocation script identifies System Capability Resource (SCR) hours as the top 40 load hours in each of summer and winter (80 total) within the utility's nested-locality load. Each constraint-group annual value is spread across those 80 hours using a two-level weight:

$$w_h = \underbrace{\phi_s}_{\text{season share}} \cdot \underbrace{\frac{\max(L_h - T_s,\ 0)}{\sum_{h' \in \text{season } s} \max(L_{h'} - T_s,\ 0)}}_{\text{within-season share}}$$

where:

- L_h — load in hour h
- T_s — season s's SCR threshold: the 41st-highest load hour, below which $w_h = 0$
- ϕ_s — season share: the fraction of the annual cost allocated to season s, equal to $(\text{peak}_s - \tau_{\min}) / \sum_{s'} (\text{peak}_{s'} - \tau_{\min})$, where peak_s is the highest load in season s and $\tau_{\min} = \min_s T_s$

The within-season factor distributes a season's cost across its 40 SCR hours in proportion to how far each hour's load exceeds the threshold T_s. The season factor ϕ_s then scales each season's total share by how much its peak rises above the lower season's threshold — so a locality whose winter peak is well above its summer peak assigns proportionally more cost to winter hours. Weights sum to 1.0 globally (validated to 1e-4).

5. **Utility blend.** The blend script combines each utility's paying-locality streams using the utility's capacity-obligation shares from the zone mapping, yielding the utility's hourly bulk-TX $/kW-hr.

The seasonal SCR window (40 + 40) — rather than a single monthly top-N — reflects that bulk-transmission constraints can bind in either season, and the two-level weight lets winter-peaking localities receive proportionate cost recovery.

Sub-transmission and distribution. Each NY utility filed a Marginal Cost of Service (MCOS) study in 2025 as part of PSC Docket 19-E-0283. These studies project planned capital investments in local grid infrastructure — substations, feeders, and sub-transmission lines — over a multi-year horizon. From each study, we extract a **diluted marginal cost**: the annualized cost of new infrastructure divided by the utility's total system peak, expressed in $/kW-yr. This represents the expected infrastructure cost of adding one kW of peak load to the system, accounting for the fact that most grid components have spare capacity (headroom).

We use the **incremental diluted** variant — based on the capital entering service in each year, not the cumulative total — because the BAT's economic cost concept requires the cost *caused by new load*, not the carrying charges on historical investment (which belong in the residual). The 2026–2032 window is harmonized across utilities — individual MCOS filings cover 8–11 years, and we truncate each to the common seven-year horizon so values are comparable. Levelization is a simple arithmetic mean over those seven years, with no discounting; some utility workbooks report WACC-based NPV levelizations, but the BAT allocates costs to a specific year's load rather than to a present-value equivalent, so we use the undiscounted average. Studies filed in 2025 dollars (ConEd, O&R, PSEG-LI) are rebased to real 2026 dollars using BLS CPI (U.S. Bureau of Labor Statistics 2025) so all seven utilities share a common base year. The per-utility values, levelized over 2026–2032 in real 2026 dollars, are:

Utility	Sub-TX + Dist MC	Study preparer
PSEG-LI	$1.16/kW-yr	PSEG-LI staff
O&R	$3.90/kW-yr	NERA
Central Hudson	$3.93/kW-yr	Demand Side Analytics (NERA method)
RG&E	$4.36/kW-yr	CRA International
NYSEG	$4.40/kW-yr	CRA International
National Grid (NiMo)	$4.49/kW-yr	NiMo staff
Con Edison	$8.52/kW-yr	NERA

The per-utility derivation of these values — including project classification, bulk-TX exclusion, annualization, and levelization — is detailed in p. 137 below.

The \$/kW-yr cost is allocated to the top 100 hours of each utility's system load (from EIA Form 930) using a **probability-of-peak** (PoP) method. Each peak hour's weight is proportional to its absolute load rather than its exceedance above a threshold:[81]

$$MC_h^{\text{dist}} = \frac{L_h}{\sum_{h' \in \text{top } 100} L_{h'}} \times \overline{MC}^{\text{dist}}$$

where:

- L_h — utility system load in hour h (from EIA Form 930)
- $\overline{MC}^{\text{dist}}$ — sub-TX + distribution marginal cost (\$/kW-yr) from the MCOS study

The four components combine into two cost categories — **supply** and **delivery** — which are modeled as separate CAIRO simulation runs:

$$MC_h^{\text{supply}} = MC_h^{\text{energy}} + MC_h^{\text{gen cap}}$$

$$MC_h^{\text{delivery}} = MC_h^{\text{bulk tx}} + MC_h^{\text{dist}}$$

The total marginal cost in each hour is the sum of both:

$$MC_h = MC_h^{\text{supply}} + MC_h^{\text{delivery}}$$

Each customer's economic burden is computed by multiplying their hourly consumption by the marginal cost in that hour and summing across all hours of the year:

$$EB_i = \sum_{h=1}^{8760} L_{i,h} \times MC_h$$

Customers who consume more electricity during peak hours — when capacity costs are nonzero — bear a larger economic burden than customers whose load is concentrated in off-peak hours.

81 EIA Hourly Electric Grid Monitor (Form 930) — hourly demand by balancing authority. (EIA 2025). Hourly sub-TX + distribution MC signals are built by the RDP.

Marginal costs tell us what each customer's load pattern *costs the system going forward*, but the utility needs to collect far more than that. The **revenue requirement** is the total amount regulators authorize the utility to recover from ratepayers each year — covering not just new infrastructure but also the carrying charges on decades of past investment, operations and maintenance, the regulated return on the rate base, and program surcharges. This is the dollar amount we need to divide fairly between the HP and non-HP subclasses. The delivery revenue requirement alone dwarfs the revenue that marginal cost pricing would generate, so how we allocate the difference — the residual — determines most of each customer's bill.

Revenue requirement

The total revenue requirement we simulate against is assembled from two sources. The **delivery revenue requirement** comes from each utility's most recent rate case — a fixed dollar amount derived from the utility's own embedded cost-of-service study. The **top-up charges** (program surcharges, supply commodity, and other volumetric charges not part of the rate-case delivery amount) are estimated separately: we take the actual filed $/kWh rates for each charge from 2025 tariff schedules and multiply them by the ResStock kWh to produce annual dollar budgets.[82]

82 The top-up process means the assumptions behind the rate-case delivery revenue requirement (the utility's own customer count and kWh projections) are not the same as those used for top-up budgets (EIA customers and ResStock kWh). The delivery amount was designed to be recovered from a specific volume of kWh; we recover it from a different volume (typically larger), so the simulation's calibrated delivery rates are somewhat lower than the rates the utility actually filed. See RDP for details on top-ups.

Residential delivery revenue requirement

Residential delivery revenue requirements come from the most recent rate case for each utility. The exception is PSEG-LI, which operates under a unique regulatory structure (LIPA as municipal owner, PSEG-LI as contract operator) and does not report a delivery-only revenue requirement for the residential class.

Utility	Effective start	Effective end	Revenue requirement ($000s)	Source
Central Hudson	July 1, 2025	June 30, 2026	$394,388	Docket 24-E-01580 (CenHud 2025b)
Niagara Mohawk	April 1, 2025	March 31, 2026	$1,314,441	Docket 24-E-0322 (NiMo 2025b)
Orange & Rockland	January 1, 2025	December 31, 2025	$248,359	Docket 24-E-0060 (O&R 2024)
Rochester Gas & Electric	May 1, 2025	April 30, 2026	$325,583	Docket 25-E-01376 (NYSEG, RG&E 2025b)
New York State Electric & Gas	May 1, 2025	April 30, 2026	$834,674	Docket 25-E-01376 (NYSEG, RG&E 2025b)
Con Edison	January 1, 2025	December 31, 2026	$3,116,197	Docket 25-E-00241 (ConEd 2025c)

Residential delivery revenue requirements ($000s)

Why there is a residual revenue requirement

Marginal costs capture only the forward-looking incremental cost of new infrastructure — the specific projects in each utility's current capital plan and the next MW of generation and transmission capacity. In rate design, this is typically called the long-run marginal cost (LRMC): the cost of serving an additional unit of demand when the infrastructure stock can be fully adjusted over time. The capital plan serves as a practical proxy for LRMC; it captures near-term investment needs but may not fully reflect long-run equilibrium costs. Marginal costs do not capture the embedded cost of existing infrastructure: carrying charges on past investments, operations and maintenance on sunk assets, regulatory return on the rate base, or customer-related costs. These are real costs that the utility must recover, but they are not caused by any individual customer's current consumption decisions.

residual

The gap between a utility's total revenue requirement and the revenue that marginal-cost pricing alone would recover. It reflects embedded (sunk) costs — depreciation, carrying charges, O&M — that are not captured by forward-looking marginal costs.

revenue requirement

The total amount of money a utility is authorized to collect from a customer class (or subclass) over a given period, as determined during a rate case. The revenue requirement is set to match the group's cost of service: the utility designs rates so that, when applied to the group's expected usage, the resulting bills add up to the revenue requirement. If the revenue requirement is set too high, the group overpays; if too low, it underpays and other customers make up the difference.

The gap between the utility's total revenue requirement and the revenue that marginal cost pricing generates is the residual. For New York's utilities, the delivery residual typically represents 87–98% of total delivery revenue — only a small fraction of what customers pay for delivery reflects the forward-looking cost of new infrastructure.

How we allocate the residual

Because the residual represents sunk costs that are not attributable to any customer's current behavior, the choice of how to split it is a normative decision, not a strictly economic one. We use **lump-sum** allocation for the delivery residual: each customer bears an equal share of the residual, regardless of consumption or marginal cost contribution. This treats every customer as an equal beneficiary of the existing grid: since sunk costs have already been incurred and today's consumption decisions cannot change them, dividing them equally among grid users is the most straightforward equitable choice.

Under per-customer allocation, each customer's share of the residual is:

$$\text{Residual}_i = \frac{R}{N_{\text{total}}}$$

and the HP subclass's delivery cost of service is:

$$RR_{\text{HP}} = EB_{\text{HP}} + \frac{N_{\text{HP}}}{N_{\text{total}}} \times R$$

where:

- R — total delivery residual (revenue requirement minus total economic burden)
- N_{HP}, N_{total} — HP and total residential customer counts
- EB_{HP} — total HP subclass economic burden

Other **residual allocation methods** exist:

- **EPMC** (equi-proportional marginal cost) allocates the residual in proportion to each subclass's share of total marginal costs.
- **Volumetric** allocation splits it by kWh share.
- **Ramsey pricing** allocates inversely to demand elasticity.

Each would produce different subclass cost-of-service estimates; lump-sum is the most equal-treatment choice and is the one applied in the results reported here.

Under lump-sum allocation, the BAT reveals how the current delivery rate redistributes costs between customer groups. Heat pump customers consume more electricity overall, and their additional consumption is concentrated in winter — a season when capacity marginal costs are low because the system peaks in summer. Under flat delivery rates, these winter kWh are billed at the same $/kWh as summer kWh, so HP customers pay a disproportionate share of the delivery revenue requirement relative to the cost they impose on the system.[83]

83 BAT values, per-customer economic burden, and cross-subsidy are computed by CAIRO during the run. The RDP then applies the per-customer split between HP and non-HP subclasses. BAT results are consolidated across utilities by the RDP.

Supply bills are held constant

The rate-design changes we evaluate apply to the **delivery** portion of the bill only. Each customer's **supply** bill is held at what they would pay under their utility's default supply tariff — both under today's rates and under the proposed HP rates. We do not reallocate the supply revenue requirement between HP and non-HP subclasses.

Two reasons. First, residential supply charges in New York are entirely volumetric ($/kWh); there is no fixed supply charge. Holding the supply rate fixed therefore means each subclass's share of supply revenue is simply its kWh share — the same allocation a volumetric method would produce. Second, holding supply bills constant reflects the status quo: the supply charge a customer sees today is the outcome of the utility's existing supply tariff, not a BAT-style cost allocation, and we do not attempt to decompose that charge into separate marginal-cost and residual components on the supply side.[84]

84 From the supply tariff alone, the decomposition into a marginal-cost share and a residual share is not uniquely identified — any pair of shares that sum to the observed bill is consistent with the tariff. See the RDP for the full argument.

The delivery-side cross-subsidy results in this report are not sensitive to this choice, because the supply rate is the same under every scenario we compare.

HOW WE DESIGNED THE PROPOSED FAIR RATES

The cross-subsidy analysis (p. 114) identifies the problem: under today's flat delivery rates, heat pump customers systematically overpay for delivery. We propose two rate designs to address this — a **seasonal flat rate** and a **seasonal time-of-use rate** — both calibrated to eliminate the cross-subsidy at the subclass level. Each utility gets its own rates, reflecting its territory's cost structure.

The HP seasonal flat delivery rate

The simplest fix is a flat volumetric delivery rate for HP customers, differentiated by season (summer and winter). The rate is calibrated so that HP customers' total delivery revenue equals their **cost of service** on a subclass basis, eliminating the cross-subsidy. Each utility gets a separate pair of seasonal rates reflecting its territory's cost structure.

The calibration works as follows. The HP subclass's cost of service is its **economic burden** plus its per-customer share of the residual (see p. 124). The HP seasonal rate for each season is the volumetric charge that recovers exactly this cost of service from the HP subclass's consumption in that season:

$$r_{\text{HP, season}} = \frac{RR_{\text{HP, season}} - FC_{\text{HP, season}}}{Q_{\text{HP, season}}}$$

where:

- $RR_{\text{HP, season}}$ — HP subclass revenue requirement for that season (per-customer-allocated share of the total delivery **revenue requirement**)
- $FC_{\text{HP, season}}$ — fixed-charge revenue already collected from HP customers in that season
- $Q_{\text{HP, season}}$ — total HP kWh delivered in that season

By construction, this rate collects exactly the HP subclass's allocated cost of service.[85] Non-HP customers remain on a slightly recalibrated default rate that absorbs the revenue previously cross-subsidized by HP customers.

85 The fair seasonal flat delivery rate is derived by the RDP.

The electric heating seasonal delivery rate

The HP seasonal rate corrects the cross-subsidy that heat pump customers pay into, but heat pump customers are not the only electric heating customers who overpay. Electric resistance customers — baseboard heaters, wall units, and older forced-air systems — also consume disproportionately in winter and overpay under flat volumetric delivery rates for the same structural reason.

The electric heating rate extends the seasonal rate's logic to a broader subclass. Instead of splitting customers into HP vs. non-HP, we redefine the subclass boundary: **electric heating** (heat pump + electric resistance) vs. **non-electric-heating** (natural gas, fuel oil, propane). The BAT is re-run with this wider boundary, producing a combined cost of service for all electric heating customers. The seasonal rate formula is identical to the HP-only version — summer volumetric rate matches the default, winter rate lowered — but calibrated to the combined electric heating subclass's revenue requirement.[86]

86 The electric heating rate uses the same RDP calibration script as the HP seasonal rate, with the subclass definition widened to include electric resistance customers.

Because the electric heating subclass is larger (more customers, more kWh), the cross-subsidy being unwound is correspondingly larger, and the recalibrated default rate for non-electric-heating customers rises by more than under the HP-only rate. The findings in p. 41 quantify this tradeoff.

The HP seasonal time-of-use delivery rate

The seasonal flat rate solves the fairness problem — heat pump customers pay their fair share — but it does not send a price signal about *when* customers consume. A time-of-use (TOU) rate goes further: it varies the price by time of day, charging more during peak hours (when grid infrastructure costs are concentrated) and less during off-peak hours. This creates an incentive for customers with programmable heat pumps to shift load away from peaks, reducing system costs.

Demand-weighted MC per period. The TOU rate divides each day into a peak period and an off-peak period. The rate for each period is the demand-weighted average marginal cost within that period:

$$\overline{MC}_{\text{peak}} = \frac{\sum_{h \in \text{peak}} MC_h \times L_h}{\sum_{h \in \text{peak}} L_h}$$

and similarly for off-peak. The **cost-causation ratio** — $\overline{MC}_{\text{peak}}/\overline{MC}_{\text{offpeak}}$ — measures how much more expensive peak hours are than off-peak hours. A higher ratio means a stronger price signal.

Optimal peak window. The width of the peak period (how many hours per day) is a design choice. Too narrow, and most capacity costs fall outside the peak; too wide, and the peak rate is diluted by low-cost hours. We optimize this for each utility by sweeping peak widths from 1 to 23 hours and selecting the width N that minimizes the HP-load-weighted squared deviation between the two-period TOU prices and the true hourly marginal costs:[87]

$$\mathcal{L} = \sum_h L_h^{\mathrm{HP}} \times \left(MC_h - \overline{MC}_{\mathrm{period}(h)}\right)^2$$

The same N applies to both summer and winter, but the optimal start/end hours can differ by season. Contiguity is enforced — the peak period is a single unbroken block of hours — for customer usability.

The resulting peak windows for each utility are:

Utility	Peak width	Summer peak	Winter peak
Con Edison	3 hours	16:00–19:00	16:00–19:00
National Grid	3 hours	17:00–20:00	17:00–20:00
NYSEG	3 hours	17:00–20:00	17:00–20:00
RG&E	3 hours	17:00–20:00	17:00–20:00
Central Hudson	5 hours	16:00–21:00	16:00–21:00
O&R	5 hours	16:00–21:00	16:00–21:00
PSEG-LI	5 hours	16:00–21:00	16:00–21:00

Calibration to revenue requirement. The TOU period prices (peak and off-peak, by season) are expressed as ratios derived from the demand-weighted MC formula. CAIRO then calibrates the absolute price level so that total revenue from the TOU rate equals the heat pump subclass's per-customer-allocated revenue requirement — the same dollar amount as the seasonal flat rate, but distributed across time periods.

Bill comparisons under the proposed rates

Once the rates are calibrated, we compute additional sets of bill comparisons using the same building-by-building, undiscounted methodology described above:

87 TOU window optimization implemented in the RDP. The optimization uses HP-class loads specifically (not all residential) because the TOU rate applies to HP customers. Results for each utility are committed in the RDP's config directory.

- **HP customers switching under the proposed rate.** We compare each building's total energy bill under its current heating equipment on default rates (upgrade 0, default rate) against its bill after a heat pump retrofit on the proposed rate (upgrade 2, HP seasonal or TOU rate). This captures the combined effect of electrification and rate reform.
- **Non-HP customers after cross-subsidy removal.** If HP customers move to the proposed rate, the default rate is recalibrated for remaining customers. We compare non-HP customers' bills before and after this recalibration — same homes (upgrade 0), same heating equipment, only a slight rate adjustment.

DEMAND FLEXIBILITY

TOU rates create a financial incentive to shift electricity use away from peak hours — running the heat pump harder before the peak period, for instance, or letting the house coast during peak hours and recovering afterward. This is demand flexibility: customers responding to price signals by changing *when* they consume electricity, without reducing how much they consume overall.

The demand flexibility analysis models how heat pump customers shift electricity consumption from peak to off-peak hours in response to TOU price signals. The key parameter is the elasticity of substitution (ε), which controls how much load shifts for a given peak-to-off-peak price ratio.[88] In other words, how willing a home is to change their energy use for a given price increase during the peak period. We calibrate this parameter separately for each utility and season, anchored to empirical evidence from real TOU pricing pilots.

88 A more negative elasticity means more load shifts away from peak hours for a given peak-to-off-peak price ratio. The bigger the difference between the peak and off-peak rates, the more customers shift their demand.

How much loads shift

We ground our elasticity in the Arcturus 2.0 meta-analysis (Faruqui et al. 2017), which synthesized results from 62 residential time-varying pricing pilots across North America, Europe, and Australia. The study's central finding is that peak demand reduction is strongly predicted by the peak-to-off-peak price ratio. The relationship is log-linear. Arcturus estimates two models:

No enabling technology (customers responding to price signals alone, without smart thermostats or automation):

$$\text{peak reduction} = -0.011 + (-0.065) \times \ln(\text{price ratio})$$

At a 2:1 price ratio, this predicts ~5.6% peak reduction; at 4:1, ~10.1%. Returns diminish as the ratio increases.

With enabling technology (customers with smart thermostats or programmable devices):

$$\text{peak reduction} = -0.011 + (-0.111) \times \ln(\text{price ratio})$$

At the same price ratios, this predicts ~8.8% peak reduction at 2:1 and ~16.5% at 4:1 — roughly 1.5–1.6x the no-tech response. Since most modern heat pumps are programmable and can respond to price signals automatically, we use the with-tech model for our presented results. That said, the resulting bill savings from demand shifting are modest either way — on the order of \$3–\$52 per HP customer per year (25th–75th percentile; mean \$-185) — compared to the much larger savings from simply being on a TOU rate.

Calibrating the elasticity to our TOU rates

Our simulation uses a constant-elasticity model,

$$Q_{\text{shifted}} = Q \times \left(\frac{P_{\text{period}}}{P_{\text{flat}}}\right)^{\varepsilon}$$

where:

- Q — baseline electricity consumption in a given hour
- Q_{shifted} — consumption after the demand response
- P_{period} — TOU price in the relevant period (on-peak or off-peak)
- P_{flat} — flat-rate price (the revenue-neutral reference)
- ε — constant price elasticity of demand (negative)

which differs from Arcturus's log-linear regression. We cannot directly equate the two functional forms. Instead, we calibrate by:

1. Taking each utility's actual seasonal TOU price ratios (derived from marginal costs)
2. Computing the Arcturus-predicted peak reduction at those ratios
3. Running our constant-elasticity model across a sweep of ε values (-0.04 to -0.50)
4. Selecting the ε that reproduces the same peak reduction Arcturus predicts

This yields an empirically grounded elasticity — one that matches the aggregate demand response observed in real pricing pilots at a comparable price ratio.

Each NY utility has different TOU price ratios derived from its marginal cost profile. Summer ratios range from 2.87 (RG&E) to 4.33 (Con Edison); winter ratios are lower, ranging from 1.57 (Central Hudson, O&R) to 1.98 (Con Edison). Because Arcturus predicts different peak reductions at different ratios, a single statewide elasticity would overshoot some utilities and undershoot others. We calibrate each utility and season independently. The calibration runs on actual ResStock HP building loads — the same hourly consumption data used in the bill analysis — ensuring the elasticity reflects the load profile of the buildings we are modeling.

The resulting seasonal elasticities fall into two natural groups:

- Utilities with **3-hour peak windows** (Con Edison, National Grid, NYSEG, RG&E): ε = -0.16 to -0.18
- Utilities with **5-hour peak windows** (Central Hudson, O&R, PSEG-LI): ε = -0.18 to -0.24

Wider peak windows shift more kWh per unit of elasticity, so less elasticity is needed to reach the same Arcturus target. The full calibration results are in Table 24.

What the calibration captures and what it does not

The calibrated elasticities reproduce the *average* response observed across real TOU pilots. They do not capture the distribution of individual customer responses — in reality, some customers shift aggressively while others do not shift at all. Our model applies the same ε uniformly to every HP building, producing identical percentage peak reductions across all buildings. This is a known simplification.

The bill savings from demand flexibility come almost entirely from **rate arbitrage**: consuming less electricity at the peak rate and more at the off-peak rate. The system-level savings channel (lower marginal costs reducing the revenue requirement) is negligible because delivery marginal costs are nonzero in only 40–113 hours per year, leaving very little cost to shift away from.

Validation. We validated the shifting mechanics against CAIRO's own outputs for all seven NY utilities. The validation confirms energy conservation (total kWh is preserved within machine precision), correct direction (peak kWh decreases, off-peak increases), and consistency with CAIRO's internal demand response tracker (mean $|\Delta\varepsilon| < 0.003$ across all utilities).

PEAK DEMAND GROWTH FORECAST

The analysis of how New York's grid transitions from summer-peaking to winter-peaking — and when heat pump adoption begins driving infrastructure costs — draws on the 2025 NYISO Gold Book (NYISO 2025b) and the Synapse Energy Economics distribution headroom assessment (Takahashi et al. 2024).[89]

89 Peak growth analysis and all figures in this section are produced by the Gold Book peaks notebook.

Data sources

The Gold Book publishes zonal (A–K) forecasts of coincident peak demand through 2055 under two scenarios — baseline and lower demand. We ingest 15+ forecast tables from the Gold Book Excel workbooks:

Table(s)	Content
I-3a, I-3b	Summer and winter coincident peak (CP) totals
I-4a, I-4b	Summer and winter non-coincident peak (NCP)
I-13b, I-13c	Building electrification incremental CP
I-11c, I-11d	EV incremental CP
I-14	Large loads (summer and winter)
I-8b, I-8c	Energy efficiency reductions
I-10b, I-10c	Non-solar distributed generation reductions
I-12b, I-12c	Behind-the-meter storage reductions

Utility-level aggregates are computed by summing zones according to a fixed zone-mapping: National Grid and NYSEG & RGE each sum zones A–F; Con Edison sums G–J; Central Hudson and O&R each use zone G only.

Peak decomposition

The Gold Book reports net peak forecasts that already incorporate negative drivers (energy efficiency, non-solar DG, BTM storage). To decompose net peak growth into four positive drivers — building electrification, EV load, large loads, and organic growth (economic activity, population, weather) — we scale each gross driver increment so the components sum exactly to the net forecast:

$$s = \frac{\Delta P_{\text{net}}}{\Delta P_{\text{net}} + N}$$

where:

- ΔP_{net} — net peak growth above the base year (forecast CP minus base-year CP)
- N — total negative reductions in that year (EE + non-solar DG + storage)
- s — scale factor applied to each gross driver increment

Each driver's net contribution is its gross Gold Book increment multiplied by s. Organic growth is the residual: net peak growth minus the scaled contributions of building electrification, EV load, and large loads. This distributes the negative sources proportionally across all growth drivers rather than attributing them to any single driver.

Season crossover

The season crossover year — when the winter coincident peak first exceeds the summer coincident peak — is computed by linear interpolation. If year t is the last year where summer CP exceeds winter CP, and year $t+1$ is the first year where winter CP $\geq$ summer CP:

$$t_{\text{cross}} = t + \frac{S_t - W_t}{(S_t - W_t) + (W_{t+1} - S_{t+1})}$$

where S_t and W_t are the summer and winter coincident peaks in year t. The crossover is computed both NYCA-wide (summing all 11 zones) and per utility. Per-utility crossover calculations exclude large loads — which connect at substations rather than feeders — so the crossover reflects distribution-relevant demand.

Distribution headroom exhaustion

To estimate when heat pump adoption begins driving distribution capacity costs, we combine the Gold Book's per-zone NCP forecasts with the Synapse Energy Economics adjusted total distribution headroom (in MW) for each utility (Takahashi et al. 2024). The headroom exhaustion year is the first forecast year in which the utility's NCP (excluding large loads) reaches the threshold:

$$\text{NCP}_{\text{excl. LL}}(t) \geq \text{NCP}_{\text{base, excl. LL}} + H$$

where:

- $\text{NCP}_{\text{base, excl. LL}}$ — base-year (2023–24) non-coincident peak excluding large loads
- H — Synapse adjusted total distribution headroom (MW)

The exhaustion year is linearly interpolated between the last year below the threshold and the first year at or above it. Central Hudson (summer-constrained headroom) and Con Edison (unreliable headroom data) are excluded from this calculation. For the remaining utilities, the threshold reflects the physical distribution capacity available before new feeder and substation investment is triggered.

Adoption curve fitting

The NYISO household adoption forecast (Figure 36) is produced by digitizing cumulative band edges from the NYISO Gold Book reference chart image, then fitting a three-parameter logistic function to each technology layer:

$$f(t) = \frac{L}{1 + e^{-k(t-t_0)}}$$

where L is the saturation level (as a fraction of NY residential electric customers from EIA-861), k is the growth rate, and t_0 is the inflection year. The fitted sigmoids are stacked to produce the adoption ribbons shown in the figure.

LOW-INCOME DISCOUNT METHODOLOGY

New York's Energy Assistance Programs

New York's low-income bill assistance operates through the **Energy Affordability Program (EAP)** and, since late 2025, the **Enhanced Energy Affordability Program (EEAP)**. New York uses **fixed monthly bill credits** — dollar amounts that vary by utility, by tier, and by whether the household heats with that fuel.

The EAP/EEAP system assigns households to seven tiers based on income relative to federal and state thresholds:

Tier	Eligibility	Program
1	≤60% SMI, not eligible for higher tiers	EAP
2	≤130% FPL, utility-heated, not vulnerable	EAP
3	≤130% FPL, utility-heated, vulnerable household	EAP
4	DSS referral (program enrollment required)	EAP
5	>60% SMI but ≤60% AMI (or ≤60% SMI for non-AMI territories)	EEAP
6	60–80% AMI (or SMI)	EEAP
7	80–100% AMI (or SMI)	EEAP

SMI = State Median Income; AMI = Area Median Income (used by Con Edison, KEDNY, KEDLI); FPL = Federal Poverty Level.

Most upstate utilities use SMI as the income benchmark for EEAP tiers 5–7. Con Edison and the KeySpan gas utilities (KEDNY, KEDLI) use Area Median Income (AMI), which is higher than SMI in the New York City and Long Island metro areas — expanding eligibility to more households. PSEG-LI operates a separate **Household Assistance Program (HAP)** with a flat $45/month credit regardless of tier or heating status.[90]

90 EAP/EEAP credit amounts by utility and tier are committed in the RDP, compiled from utility filings and public EAP program pages as of February 2026.

How we apply discounts in the simulation

Because ResStock does not include program enrollment data, we assign EAP/EEAP tiers based on household income from ResStock metadata. We inflate ResStock's 2019-dollar income to 2025 dollars using the BLS CPI-U (U.S. Bureau of Labor Statistics 2025), then compute each household's income as a percentage of FPL (adjusted for household size) and SMI (or AMI in applicable territories). Tier assignment follows the rules above, except that we do not assign Tier 4 (which requires DSS referral data we cannot observe).[91]

91 LMI tier assignment and discounts are applied by the RDP, using RDP shared tier logic and RDP EAP credit tables.

We model two enrollment scenarios: **~40% participation** (reflecting current estimated enrollment rates) and **100% participation** (reflecting universal automatic enrollment). Under partial participation, we sample eligible households using weighted random selection with a fixed seed for reproducibility.

Computing energy burden

A household's energy burden is the share of annual income spent on energy. We define a household as **highly energy burdened** if this share exceeds 6%.[92] For each ResStock building:

92 The 6% threshold is a commonly used benchmark in energy affordability research. We apply it to total energy costs (electric + gas + delivered fuels), not electricity alone.

$$\text{Energy burden}_i = \frac{\text{Electric bill}_i + \text{Gas bill}_i + \text{Delivered fuel bill}_i}{\text{Annual household income}_i}$$

We focus on a cohort of LMI gas-heated households — those flagged as low-or-moderate income who heat with natural gas in the baseline scenario — and track their energy burden across three rate scenarios (current HVAC on default rates; heat pump on default rates; heat pump on HP seasonal rates), under both partial and full enrollment assumptions. This lets us isolate the separate effects of rate reform and discount take-up on low-income energy affordability.

SUB-TRANSMISSION AND DISTRIBUTION MARGINAL COSTS BY UTILITY

This section documents how we derived the sub-TX + distribution marginal cost for each utility from its 2025 MCOS filing. The seven utilities used different MCOS consultants and methodologies; we harmonized them into a common framework — incremental diluted $/kW-yr, levelized over 2026–2032 in real 2026 dollars — for cross-utility comparability and BAT input.

Con Edison and Orange & Rockland

Con Edison and O&R (its subsidiary) both use the NERA Economic Consulting marginal cost methodology — an approach developed in the late 1970s for EPRI's Electric Utility Rate Design Study that uses economic carrying charges to annualize marginal capital costs — which organizes investment into **cost centers** corresponding to different levels of the grid.[93] Their MCOS workbooks present costs in an undiluted form — $/kW of new capacity — so we needed to compute the diluted values ourselves.

Unlike NiMo, ConEd required no project-level classification — its workbook already separates costs into cost centers that map directly to grid tiers: **Transmission** (138–345 kV) covers bulk transmission, which we exclude, and the remaining cost centers — **Area Station & Sub-Transmission**, **Primary**, **Transformer**, and **Secondary** — are the sub-transmission and distribution investments we use as BAT inputs. We verified ConEd's two Transmission projects against the NYISO Gold Book.[94]

O&R required a partial split of its "CapEx Transmission" worksheet (O&R 2025b). Of three 138 kV projects, only West Nyack appears in the Gold Book; Oak Street and New Hempstead (both 138 kV reconductoring) do not. Under a "Gold Book entries = bulk TX" approach, these two projects would fall through the gap — excluded from our analysis but absent from

93 See ConEd's 2025 MCOS filing, Docket 19-E-0283 (ConEd 2025a). O&R's filing: (O&R 2025a).

94 ConEd's two Transmission projects (Eastern Queens 138 kV and Brooklyn Clean Energy Hub 345 kV) both appear in Gold Book Table VII.

the bulk TX analysis too. We reclassify them as local sub-transmission and include them in the sub-TX + distribution total.[95]

The area station and sub-transmission cost center bundles both sub-TX feeders and distribution substation transformers in the same projects (e.g., a 138/27 kV transformer installed alongside a 138 kV feeder). We cannot separate these into distinct sub-TX and distribution tiers, but for the BAT this is acceptable: what matters is excluding bulk TX, and the bundled "Substation" cost center correctly captures all local delivery investment at both levels.

MC formula. For each cost center and year, we computed:

$$\text{Annual RR}(Y) = \text{Capital}(Y) \times r \times e(Y)$$

$$\text{MC}_{\text{diluted}}(Y) = \frac{\text{Annual RR}(Y)}{P}$$

where:

- $\text{Capital}(Y)$ — in-service capital ($000s); cumulative (all projects through year Y) or incremental (new projects entering service in Y)
- r — composite rate: the "Annual MC at System Peak" carrying charge from Schedule 11 (ConEd) or Schedule 10 (O&R), which folds together the Economic Carrying Charge, O&M + A&G loading, and the area-station-to-system coincidence adjustment
- $e(Y)$ — GDP Implicit Price Deflator escalation factor for year Y, read per-year from the workbook (2.4% in 2026, then 2.1%/yr from 2027 onward)
- P — system peak demand (MW), held constant across years: ConEd's 2025 area station coincident total (11,998 MW) or O&R's 2024 coincident forecast (1,079 MW)

The composite rate already embeds the area-station-to-system diversity adjustment (coincidence factor ≈0.95 for ConEd; O&R's carrying charge schedule embeds a similar adjustment). Dividing by the area station coincident total (rather than the lower system coincident peak) is therefore correct.[96]

Cumulative vs. incremental capital. MCOS studies present marginal costs using *accumulated* capital — the running total

95 Justification: (1) not in Gold Book Table VII — not NYISO-jurisdictional bulk TX; (2) 138 kV reconductoring of existing local lines, not new backbone capacity; (3) small scale ($29M + $7.5M) serving O&R's Eastern NY load area; (4) without reclassification, $36.5M in capital falls through the gap. These projects use the Transmission composite rate (same plant type / carrying charge characteristics).

96 ConEd: Coincident Load sheet, 2025 area station coincident total (ConEd 2025b). O&R: Coincident Forecast sheet, 2024 value (O&R 2025b). Both from the respective MCOS workbooks. Using the area station coincident total (rather than the lower system coincident peak) is correct because the composite rate already includes the area-to-system diversity adjustment.

of all projects in service through each year. This is appropriate for utility cost allocation (total revenue requirements), but the BAT's economic cost concept calls for *incremental* marginal cost: the cost caused by new load in a given year, which depends on the capital *entering service* that year, not the historical total. We compute both perspectives:

- **Cumulative** Capital(Y) = total in-service capital through year Y (what MCOS studies report)
- **Incremental** Capital(Y) = new capital entering service in year Y (year-over-year delta)

For the BAT inputs, we use the **incremental diluted** values: new capital per year divided by the system peak.[97] This gives the marginal cost of serving one additional kW of peak load in year Y — the cost signal appropriate for economic efficiency. The cumulative values are retained for cross-checking against the MCOS study's own Schedule 1/2 tables.

97 The distinction matters because MCOS capital budgets are front-loaded: most large projects enter service early in the study period, so incremental costs decline over time while cumulative costs grow monotonically. As a sanity check, cumulative and incremental values are identical in the first study year (2025) since there is no prior accumulation.

Levelized results. We averaged the real (base-year) incremental diluted MC across all study years. The sub-TX + distribution total is the sum of all cost centers excluding bulk TX:

Con Edison

Cost center	Capital	Composite rate	Levelized MC
Bulk TX (138/345 kV)	$1,447M (cumulative)	0.135	$15/kW-yr
Area Station & Sub-TX	$7,419M (cumulative)	0.128	$47/kW-yr
Primary	$13M (annual)	0.129	$0.14/kW-yr
Transformer	$6M (annual)	0.113	$0.06/kW-yr
Secondary	$17M (annual)	0.128	$0.18/kW-yr
Sub-TX + Distribution			**$48/kW-yr**

ConEd's sub-TX + distribution cost is dominated by the Area Station & Sub-TX cost center ($47/kW-yr). The distribution components (Primary, Transformer, Secondary) total less than $0.40/kW-yr because they represent a single sample year's small projects (143 demand-related projects adding 97.5 MW), while the substation cost center captures $7.4B in cumulative 10-year investment across 17 major station builds.

Levelized over 2026–2032 in real 2026 dollars, the incremental diluted BAT input for ConEd is $8.52/kW-yr. The $48/kW-yr figure above is the cumulative cost-center decomposition at the end of the study horizon; the BAT uses the incremental variant averaged over the harmonized seven-year window.[98]

O&R

Cost center	Capital	Composite rate	Levelized MC
Bulk TX (West Nyack, Gold Book)	$46M (cumulative)	0.130	$5/kW-yr
Local TX (Oak St. + New Hempstead)	$37M (cumulative)	0.130	$2/kW-yr
Area Station & Sub-TX	$200M (cumulative)	0.119	$15/kW-yr
Primary	$16M (cumulative)	0.154	$2/kW-yr
Secondary Distribution	$12.57/kW (flat)	0.137	$2/kW-yr
Sub-TX + Distribution			**$21/kW-yr**

O&R's sub-TX + distribution cost is lower than ConEd's, reflecting its smaller service territory (1,079 MW vs. 11,998 MW peak). The Local TX row captures the two non-Gold-Book 138 kV reconductoring projects reclassified as sub-transmission ($2/kW-yr). The Secondary Distribution cost center uses a flat $/kW figure derived from just two sample projects, so it has no temporal variation.

Levelized over 2026–2032 in real 2026 dollars, the incremental diluted BAT input for O&R is $3.90/kW-yr.

The full analysis scripts, cell-level workbook references, and year-by-year annualized outputs are available on GitHub.

Central Hudson

Central Hudson's 2025 MCOS study was prepared by Demand Side Analytics (DSA) using the NERA methodology.[99] The study identifies 8 named capital projects plus 3 "future unidentified" placeholders (one per cost center) across three cost centers: Local Transmission (69/115 kV), Substation, and Feeder Circuit. CenHud has a 2024 actual coincident peak of 1,103 MW.

No bulk TX. Unlike ConEd, O&R, and NiMo, CenHud has no FERC-jurisdictional bulk transmission in its MCOS study. The "Local Transmission" cost center covers 69 kV and 115/69 kV lines serving 10 local areas — all explicitly labeled "local." CenHud has no entries in NYISO Gold Book Table VII. All three cost centers are therefore included in our BAT input without exclusion.

98 ConEd and O&R report capital on an accrual basis that includes construction work in progress (CWIP). We exclude CWIP by identifying each project's in-service year from its cashflow stabilization point — the year annual spend plateaus — and counting only post-stabilization capital as entering service. This matches the treatment used by the other utilities' studies and avoids double-counting carrying charges on pre-in-service assets, which otherwise belong in the residual rather than in marginal cost.

99 See CenHud's 2025 MCOS filing, Docket 19-E-0283 (CenHud 2025a).

MC formula. CenHud's workbook provides each project's fully-loaded annual cost per kW of new capacity (row 26), which already incorporates a 30% reserve margin, 16.1% general plant loading, level-specific ECCR rates (13.72% for transmission, 13.33% for substations, 17.83% for feeders), working capital charges, and loss factors. We compute the system-wide diluted marginal cost by summing each project's total annual cost and dividing by the system peak:

$$\mathrm{MC}_{\mathrm{diluted}}(Y) = \frac{\sum_{p \in Y} \mathrm{AnnualCost}(p) \times \mathrm{Capacity}(p)}{P}$$

where:

- $\mathrm{AnnualCost}(p)$ — fully-loaded annual cost per kW of project p (row 26)
- $\mathrm{Capacity}(p)$ — project capacity (kW)
- P — 2024 system coincident peak (1,103 MW)

The workbook reports an alternative peak-share–weighted formulation; we use the capacity-based version above for cross-utility consistency.

Flat nominal costs. CenHud is the only NY utility whose filing does not apply inflation escalation — a project's $/kW-yr is identical in every year after in-service, with no GDP deflator or Blue Chip rate. Over a 10-year horizon, this understates later-year nominal costs by ~20% relative to the other utilities' ~2%/yr escalation. We treat the flat workbook values as real (base-year 2026) dollars and separately compute a nominal series by escalating at 2.1%/yr (GDP deflator) for cross-utility comparisons. The levelized BAT input uses the real (flat) series.

Cumulative vs. incremental capital. As with the other utilities, we compute both perspectives. CenHud's per-project in-service years make this straightforward — projects contribute starting in their in-service year. For the BAT inputs, we use the **incremental diluted** values.[100]

Levelized results. We averaged the incremental diluted MC across all study years:

100 First-year sanity check: in each cost center, cumulative and incremental values are identical in the first year any project contributes (2026 for Substation, 2032 for Local TX). Feeder is the exception: the Future Unidentified project (ISD 2025) enters cumulative from the first study year but has no matching incremental year.

Cost center	Projects	Capacity	Levelized MC
Local TX (69/115 kV)	3	593 MW	$3/kW-yr
Substation	6	124 MW	$1/kW-yr
Feeder Circuit	2	29 MW	$0/kW-yr
Total	**11**	**746 MW**	**$4/kW-yr**

CenHud's total incremental diluted MC ($4/kW-yr) is the lowest of the four utilities, reflecting a combination of small project budgets ($111M total capital over 10 years), a mostly stable or declining load territory (many areas have ample headroom), and the absence of escalation.

CenHud's workbook dilutes by peak-share (project MW ÷ local peak) and reports flat dollars across years. To compare across utilities we re-normalize on a capacity-based denominator (system peak MW) (CenHud 2025a). Levelized over 2026–2032 in real 2026 dollars, the incremental diluted BAT input for Central Hudson is $3.93/kW-yr.

Because projects enter service at different times, the cumulative diluted MC grows over the study period:

Year	Local TX	Substation	Feeder	Total
2026	$0/kW-yr	$0/kW-yr	$0/kW-yr	$0/kW-yr
2027	$0/kW-yr	$2/kW-yr	$0/kW-yr	$3/kW-yr
2028	$0/kW-yr	$2/kW-yr	$0/kW-yr	$3/kW-yr
2029	$0/kW-yr	$4/kW-yr	$0/kW-yr	$4/kW-yr
2030	$0/kW-yr	$10/kW-yr	$0/kW-yr	$11/kW-yr
2031	$0/kW-yr	$10/kW-yr	$0/kW-yr	$11/kW-yr
2032	$15/kW-yr	$12/kW-yr	$0/kW-yr	$28/kW-yr
2033	$15/kW-yr	$12/kW-yr	$0/kW-yr	$28/kW-yr
2034	$15/kW-yr	$12/kW-yr	$0/kW-yr	$28/kW-yr
2035	$30/kW-yr	$12/kW-yr	$0/kW-yr	$43/kW-yr

The full analysis script, cell-level workbook references, and year-by-year outputs are available on GitHub.

NYSEG

New York State Electric & Gas's 2025 MCOS study was prepared by CRA International.[101] The workbook contains per-project data for 13 operating divisions (Auburn through Plattsburgh). We read the project-level data from CRA's W2 sheet and apply **NERA-style project-level formulas** for cross-utility consistency — each project's total capital and capacity enter the MC calculation at its in-service date. NYSEG uses a **2035 forecast peak of 2,036 MW** as the diluted denominator (fixed across all study years).

No bulk TX. NYSEG's MCOS explicitly excludes NYISO Transmission Service Charges. All cost centers — upstream substation (115 kV/46 kV), upstream feeder (115 kV/34.5 kV), distribution substation (12.5 kV), and primary feeder (12.5 kV/4 kV) — are local sub-transmission and distribution, included in the BAT input without exclusion.

NERA-style aggregation. We parse 107 projects with nonzero capital from W2 (Investment Location Detail) and derive composite annualization rates from the workbook (0.10248 for substations, 0.09801 for feeders). The diluted system-wide marginal cost for each cost center in year Y is:

$$\mathrm{MC}_{\mathrm{diluted}}(Y) = \frac{\sum_{p \in Y} \mathrm{Capital}(p) \times r_p}{P}$$

where:

- $\mathrm{Capital}(p)$ — total capital cost of project p ($000s)
- r_p — composite annualization rate for project p's equipment type, folding together the Economic Carrying Charge and O&M + A&G loading (0.10248 for substations, 0.09801 for feeders)
- P — 2035 forecast system peak (2,036 MW), held constant across years

No projects enter service in 2026–2027, so those years have zero incremental MC.

Cost inflation. We apply 2.0%/yr inflation to project costs from their in-service year. For cumulative MC, prior years' contributions are inflated forward to current-year dollars before

101 See NYSEG's 2025 MCOS filing, Docket 19-E-0283 (NYSEG, RG&E 2025a).

summing. Levelization is the simple arithmetic mean of real (base-year) MC over the 2026–2032 window.

Primary voltage level. We report the “Total at Primary” at primary distribution voltage by applying demand-related loss factors from the W4 sheet:

$$\text{Total at Primary}(Y) = \sum_c \text{MC}_c(Y) \times \lambda_c$$

where λ_c is the W4 loss factor for cost center c (upstream 1.050, dist sub 1.029, primary feeder 1.022). The individual cost-center rows in the table below are pre-loss-factor values.

Levelized results. We computed the incremental diluted MC at primary voltage (real 2026 $/kW-yr, simple average across study years):

Cost center	Levelized MC
Upstream (Sub + Feeder)	$9/kW-yr
Distribution Substation	$3/kW-yr
Primary Feeder	$2/kW-yr
Total at Primary	**$15/kW-yr**

We aggregate project-level capital from worksheet W2 of the CRA workbook (NYSEG, RG&E 2025a) using the NERA method, rather than adopting CRA’s pre-computed system-level tables. The NERA-style project roll-up yields a cleaner incremental diluted value and matches the approach used in the other six utilities’ studies; the CRA system tables differ primarily in how they treat loss factors and horizon-year spikes, which would bias cross-utility comparisons. Levelized over 2026–2032 in real 2026 dollars, the incremental diluted BAT input for NYSEG is $4.40/kW-yr.

Year-by-year incremental diluted MC (nominal $/kW-yr) shows when investment enters the system:

Year	Upstream	Dist. Sub	Primary Feeder	Total
2026	$0/kW-yr	$0/kW-yr	$0/kW-yr	$0/kW-yr
2027	$0/kW-yr	$0/kW-yr	$0/kW-yr	$0/kW-yr
2028	$0/kW-yr	$3/kW-yr	$0/kW-yr	$4/kW-yr
2029	$2/kW-yr	$2/kW-yr	$0/kW-yr	$4/kW-yr
2030	$3/kW-yr	$2/kW-yr	$0/kW-yr	$5/kW-yr
2031	$4/kW-yr	$1/kW-yr	$0/kW-yr	$6/kW-yr
2032	$5/kW-yr	$6/kW-yr	$3/kW-yr	$15/kW-yr
2033	$32/kW-yr	$10/kW-yr	$1/kW-yr	$45/kW-yr
2034	$35/kW-yr	$5/kW-yr	$9/kW-yr	$51/kW-yr
2035	$28/kW-yr	$6/kW-yr	$5/kW-yr	$41/kW-yr

The full analysis script, cell-level workbook references, and year-by-year outputs are available on GitHub.

RG&E

Rochester Gas & Electric's 2025 MCOS study was also prepared by CRA International, using the same methodology as NYSEG.[102] RG&E has 4 operating divisions (Canandaigua, Central, Fillmore, Sodus) and a **2035 forecast peak of 1,429 MW**. We parse 96 projects with nonzero capital from W2.

The methodology follows the same CRA/NERA framework as NYSEG — project-level aggregation from W2, 2.0%/yr inflation, simple-mean levelization over 2026–2032, and primary voltage output — with RG&E-specific composite rates (0.10283 for substations, 0.09836 for feeders) and loss factors from W4. See the NYSEG section above for full methodology details.

102 See RG&E's 2025 MCOS filing, Docket 19-E-0283 (NYSEG, RG&E 2025a).

Levelized results (real 2026 $/kW-yr, simple average across study years):

Cost center	Levelized MC
Upstream (Sub + Feeder)	$5/kW-yr
Distribution Substation	$11/kW-yr
Primary Feeder	$2/kW-yr
Total at Primary	**$18/kW-yr**

Levelized over 2026–2032 in real 2026 dollars, the incremental diluted BAT input for RG&E is $4.36/kW-yr.

Year-by-year incremental diluted MC (nominal $/kW-yr):

Year	Upstream	Dist. Sub	Primary Feeder	Total
2026	$0/kW-yr	$0/kW-yr	$0/kW-yr	$0/kW-yr
2027	$2/kW-yr	$0/kW-yr	$0/kW-yr	$2/kW-yr
2028	$1/kW-yr	$0/kW-yr	$0/kW-yr	$1/kW-yr
2029	$0/kW-yr	$3/kW-yr	$0/kW-yr	$4/kW-yr
2030	$1/kW-yr	$2/kW-yr	$4/kW-yr	$7/kW-yr
2031	$3/kW-yr	$2/kW-yr	$1/kW-yr	$6/kW-yr
2032	$5/kW-yr	$4/kW-yr	$4/kW-yr	$14/kW-yr
2033	$9/kW-yr	$14/kW-yr	$10/kW-yr	$34/kW-yr
2034	$24/kW-yr	$25/kW-yr	$1/kW-yr	$53/kW-yr
2035	$7/kW-yr	$77/kW-yr	$2/kW-yr	$90/kW-yr

The full analysis script and outputs are available on GitHub.

PSEG-LI

PSEG Long Island (LIPA) publishes only an **undiluted** marginal cost — $146.90/kW-yr — from a shorter 8-year study (2025–2032) with 30 projects adding 1,210 MW of capacity across two cost centers: Transmission (T-Station, 1,027 MW) and Distribution (D-Station + D-Feeders, 183 MW).[103, 104]

The filing's headline $146.90/kW-yr is the **sum of two component MCs with different capacity denominators** — $46/kW of TX capacity plus $100/kW of Dist capacity — not a per-kW value applicable to the combined 1,210 MW. To dilute

103 See PSEG-LI's 2025 MCOS filing, Exhibit 1 (PSEG-LI 2025).

104 PSEG-LI's MCOS reports project capacity in MVA (apparent power). We convert to MW assuming a power factor of 1.0 — a standard simplification for T&D planning studies where the difference is typically small (a 0.95 PF would reduce these figures by ~5%).

correctly, we compute each component's total annual cost and divide by LIPA's 2024 actual system peak of 4,935 MW:[105]

105 2024 actual non-coincident peak for Zone K (Long Island), Table I-4a of the 2025 NYISO Gold Book (NYISO 2025b).

Component	Undiluted	Project capacity	Annual cost	Diluted
Sub-TX (T-Substation)	$46/kW-yr	1,027 MW	$47.4M	~$10/kW-yr
Distribution	$100/kW-yr	183 MW	$18.3M	~$4/kW-yr
Total	**$147/kW-yr**[106]	**1,210 MW**	**$65.8M**	**~$13/kW-yr**

Voltage classification. The filing labels these 15 T-Substation projects as "Transmission," but LIPA's system operates at only five voltages: 138/345 kV (Bulk Electric System, NYISO-jurisdictional) and 23/34.5/69 kV (sub-transmission).[107] We cross-referenced each T-Substation project against public sources — PSEG LI reliability project pages, LIPA environmental assessments, and NYISO interconnection queue entries in the Gold Book — and found that **all 15 operate at 69 kV or below**. Twelve have high-confidence direct voltage evidence; the remaining three have no NY Article VII filing (required for ≥100 kV), no NYISO queue entry, and project characteristics consistent with sub-TX. The Deerfield project is an edge case: the Southampton-to-Deerfield cable is *rated* at 138 kV but will *operate* at 69 kV during the entire study period (FY2025–2032). We classify it as sub-TX based on its operating voltage.

106 Sum of per-kW MCs with different denominators — not a meaningful per-kW value for the combined capacity. The correctly diluted total is the sum of the diluted components ($10 + $4 ≈ $13), not $147 × 1,210 / 4,935 ≈ $36.

107 LIPA Transmission Planning Criteria (Rev 1, Dec 2022), Section 5: "The transmission system consists of 138 kV and 345 kV voltage levels and the sub-transmission system consists of 23, 34.5 kV and 69 kV voltage levels." Section 4.1: "The entire LIPA 138 kV transmission system [is] classified as BES."

We use the **total (Sub-TX + Distribution) of ~$1.16/kW-yr** (levelized incremental diluted, 2026–2032, real 2026 dollars) as our distribution marginal cost input for LIPA. Unlike our initial analysis which used only the Distribution component (~$0.46/kW-yr), the reclassification of all T-Substation projects as local sub-transmission means both components are included — consistent with how we treat sub-TX for all other utilities.

The Exhibit 2 project list (30 projects with in-service dates, capacities, and costs) was manually transcribed from the filing PDF into a CSV on S3. A separate classification script cross-references each project's voltage and outputs a classified CSV (checked into the repo). The analysis script reads this classified CSV and uses actual per-project in-service dates for year-by-year timing, combined with Exhibit 1's aggregate ECCR+O&M rates (8.2% Sub-TX, 13.9% Dist) for MC computation. Capacity entry is heavily front-loaded: 442 MW (36.5%) enters in 2025, and no Distribution projects enter after 2029. The full analysis script and outputs are available on GitHub.

National Grid Upstate

National Grid's upstate territory (NiMo) required the most work. Unlike other utilities, NiMo publishes only an **undiluted** marginal cost — $71.52/kW-yr — which reflects the average cost per MW of *new capacity added*, not the cost per MW of *existing system load*.[108] We needed the diluted number: the annual infrastructure bill spread across all customers in proportion to their peak demand. We also needed it broken down by grid tier (bulk transmission vs. sub-transmission vs. distribution) and by year, since projects enter service at different times over NiMo's 11-year study period (FY2026–FY2036).

108 See Exhibit 1 of NiMo's 2025 MCOS filing (NiMo 2025a).

Extracting project-level data. NiMo's MCOS workbook contains one row per planned capital project — 237 projects in total. For each project, we extracted the station name, capacity added (MW), capital cost broken into four components (T-Station, T-Line, D-Station, D-Line), an annualized cost per MW (capital converted to a yearly revenue requirement via an Economic Carrying Charge Rate), and an in-service year. A few representative rows:

Station	Capacity	Capital	Annualized cost/MW (at ISD)	In-service
Sawyer Ave (distribution substation)	12 MW	$3.6M	$39k	FY2029
Altamont (distribution substation)	27 MW	$8.4M	$26k	FY2031
Transm Net (sub-TX line project)	105 MW	$93.6M	$75k	FY2029
Transm Net (Niagara-Dysinger 345kV)	1,100 MW	$142M	$11k	FY2036

Classifying projects by grid tier. NiMo's workbook labels cost components as T-Station, T-Line, D-Station, and D-Line, but does not distinguish **bulk transmission** (≥230kV) from **sub-transmission** (69–115kV). This matters for the Bill Alignment Test: bulk transmission costs are recovered through NYISO-wide charges and don't belong in a utility's local delivery marginal cost.

To separate the tiers, we cross-referenced every project against the NYISO Gold Book, which lists all planned bulk transmission projects with their voltage levels,[109] and examined sub-project detail sheets for explicit voltage labels. Of NiMo's 49 transmission-network projects, three are bulk transmission at ≥230kV: Smart Path Connect (a 230/345kV line) and Niagara-Dysinger (a 345kV line) matched Gold Book entries, while

109 See Table VII of the 2025 NYISO Gold Book (NYISO 2025b).

Eastover (a 230kV cap bank) was identified from its explicit voltage label in the sub-project detail. Together they total 2,120 MW and $1.08B in capital. The remaining 46 transmission-network projects are sub-transmission work at 69–115kV — lines and stations that step bulk voltage down to distribution levels. The 188 named-substation projects are straightforwardly distribution (≤13.2kV): substation transformers, feeders, and related equipment.

The full classification table, with voltage evidence and rationale for each project, is available on GitHub.

Computing marginal costs. NiMo's workbook provides each project's annualized cost at each fiscal year's price level via an Economic Carrying Charge Rate (ECCR), inflating at 2.1%/yr per the Blue Chip GDP deflator. The diluted marginal cost for a set of projects divides their total annualized cost by the system peak:

$$\mathrm{MC}_{\mathrm{diluted}}(Y) = \frac{\sum_{j} F_j \times C_j}{P}$$

where:

- F_j — base-year (FY2026) annualized cost per MW for project j ($000s/MW)
- C_j — capacity of project j (MW)
- P — system peak demand (MW)

We used NiMo's 2024 system peak of 6,616 MW.[110]

110 2024 actual peak from NiMo's Peak Load Forecast (March 2025) (NiMo 2026).

The full analysis is in a script on GitHub. We averaged the real (FY2026-dollar) incremental diluted MC across all study years. The levelized results:

Grid tier	Projects	Capacity	Levelized MC
Bulk TX (≥230kV)	3	2,120 MW	$1/kW-yr
Sub-TX (69–115kV)	46	6,869 MW	$7/kW-yr
Distribution (≤13.2kV)	188	2,543 MW	$4/kW-yr
Sub-TX + Distribution	**234**	**9,413 MW**	**$10/kW-yr**

The sub-TX and distribution tiers are the ones relevant to local delivery rates. We exclude bulk TX from our marginal cost inputs. The $10/kW-yr figure above is the simple average of annual incremental values across the full 11-year study (FY2026–FY2036) and is pulled higher by a large FY2036 horizon spike; the BAT uses the harmonized 2026–2032 seven-year window, which yields a levelized incremental diluted BAT input of $4.49/kW-yr for NiMo.

Because projects enter service at different times, the cumulative diluted MC grows over the study period. The following table illustrates this growth:

FY	Bulk TX	Sub-TX	Distribution	Sub-TX + Dist
2026	$0/kW-yr	$3/kW-yr	$1/kW-yr	$4/kW-yr
2027	$12/kW-yr	$6/kW-yr	$3/kW-yr	$9/kW-yr
2028	$12/kW-yr	$7/kW-yr	$4/kW-yr	$11/kW-yr
2029	$12/kW-yr	$8/kW-yr	$5/kW-yr	$14/kW-yr
2030	$13/kW-yr	$14/kW-yr	$7/kW-yr	$21/kW-yr
2031	$13/kW-yr	$17/kW-yr	$13/kW-yr	$31/kW-yr
2032	$13/kW-yr	$20/kW-yr	$16/kW-yr	$36/kW-yr
2033	$14/kW-yr	$21/kW-yr	$19/kW-yr	$40/kW-yr
2034	$14/kW-yr	$23/kW-yr	$24/kW-yr	$47/kW-yr
2035	$14/kW-yr	$31/kW-yr	$32/kW-yr	$63/kW-yr
2036	$16/kW-yr	$89/kW-yr	$48/kW-yr	$137/kW-yr

For our distribution marginal cost input, we use the **Sub-TX + Distribution** incremental diluted values. Sub-transmission lines and stations (69–115kV) deliver power to the distribution substations that serve customers — their costs are local delivery costs, not NYISO bulk system costs, and load growth drives investment at both levels.

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