Project Beacon:

Estimated Savings for Massachusetts Ratepayers

by Always On Energy Research

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Summary for Policymakers

Massachusetts consistently faces higher energy costs than the national average. Bay Staters pay the 5th-highest electricity prices in the US at 25 cents per kilowatt-hour (kWh), according to data analyzed by Always On Energy Research.[1] One major factor driving up electricity prices has been the state's limited access to affordable and reliable natural gas. In any given year, over 65% of the state's electricity comes from natural gas.[2] Expanding access to natural gas from the nearby Appalachian producing region could help reduce natural gas prices in Massachusetts and, in turn, power prices. Project Beacon, the Enbridge-led project to expand the capacity of the Algonquin Gas Transmission (AGT) pipeline interconnect by 300MMcf/d, is one such project that could put the state of Massachusetts on a better footing by 2030.

This report aims to quantify the potential benefits of Project Beacon for Massachusetts ratepayers. We find that the average residential account in the state of Massachusetts could save $76 per winter, on an average net basis, based on historical data. Commercial and industrial ratepayers could also save $622 per winter and nearly $4,600, respectively. We also find that additional capacity along the Algonquin Gas Transmission pipeline could reduce average fuel oil consumption by 8.4 million gallons by reducing oil-fired electricity generation by around 35%.

TABLE 1 | **Estimated Annual Ratepayer Savings by Customer Segment (Model Estimates & EIA Data)**

Segment	Gas total	Electric total	Gas accounts	Electric accounts	Gas $/acct	Electric $/acct	Combined $/acct	Beacon Cost to Consumer	Net Benefit $/acct
Residential	$115.4M	$68.2M	1,604,279	2,924,535	**$72**	**$23**	**$95**	**$19**	**$76**
Commercial	$85.2M	$77.5M	138,545	438,014	**$615**	**$177**	**$792**	**$170**	**$622**
Industrial	$30.1M	$19.1M	10,916	10,353	**$2,756**	**$1,842**	**$4,598**	**-**	-

Source: Analysis of EIA gas and electric accounts data.[3,4] Industrial customers, who largely buy their own gas and simply transport it on the pipeline, fall outside this allocation.

1 *Always On Energy Research*
2 *Always On Energy Research*
3 *EIA*
4 *EIA*

Introduction

Massachusetts's geological lack of natural gas reserves, a cold winter climate, and insufficient pipeline infrastructure all conspire to raise natural gas prices beyond the national average. This report seeks to estimate the potential economic effects of additional natural gas pipeline capacity on Massachusetts ratepayers, including reductions in natural gas and power prices and the quantity of fuel oil displaced.

Massachusetts consistently faces higher energy costs than the national average. Bay Staters pay the 5th-highest electricity prices in the US, at 25 cents per kilowatt-hour (kWh), according to data from the U.S. Energy Information Administration (EIA). One major factor driving up electricity prices is the state's limited access to affordable, reliable natural gas. In any given year, over 65% of the state's electricity comes from natural gas.[5]

However, Massachusetts has insufficient pipeline capacity to meet the demand of its residents, businesses, and power plants. This problem is magnified during winter storms, when Massachusetts faces some of the most temperamental cold fronts and, as a result, volatile natural gas prices in the Northeast. Recently, in January 2026, winter storm Fern pushed Algonquin wholesale natural gas prices over $120 per million British thermal units (MMBtu) due to the state's limited pipeline capacity, according to Natural Gas Intelligence.[6] Subsequently, the day-ahead wholesale electricity price averaged $382/MWh for the week of January 26th, 2026.[7] Barring additional pipeline infrastructure improvements, Massachusetts will likely continue to experience volatile energy prices as long as New England winters remain cold.

By expanding existing pipelines, Project Beacon would add 300 MMcf of natural gas capacity and increase transmission along the Algonquin line by 10%.[8] The additional capacity could alleviate natural gas and electricity supply issues that are exacerbating Massachusetts' energy security crisis. This additional capacity could reduce natural gas prices by $1.27/MMBtu on average every winter. Lower natural gas prices would reduce electricity generation costs, passing additional savings to households and businesses.

Table 1 in the following section reports the estimated change in prices under Project Beacon, along with the total pass-through cost savings to Bay State families. A typical household would save $95 on their gas and electricity bills each winter, compared to a cost of $19 dollars, a savings ratio of 5:1.

Project Beacon Estimated Savings

Applied to the seven winters from 2019/20 through 2025/26, Project Beacon could have saved

5 *Always On Energy Research*

6 *Natural Gas Intelligence*

7 Always On Energy Research analysis of ISO-NE

8 *Natural Gas Intelligence*

Massachusetts ratepayers an average of $367 million per winter across both natural gas and power savings. Residential customers capture $184 million, commercial customers $163 million, and industrial customers $49 million on the electricity side. The savings are concentrated during particularly cold winters – $627 million in 2025/26 and $516 million in 2021/22, compared with $181 million in the mild winter of 2023/24. Savings are highest during the coldest winters and lowest during mild winters because extreme cold drives surges in natural gas demand, which can consume most or all of the available pipeline capacity and drive prices up dramatically.

To break down how individual households and businesses would benefit from lower natural gas prices, we use our model results and scale them by the total number of gas and electric customers in Massachusetts, as reported by the EIA. A gas-heated Massachusetts account would have saved about $76 per winter on average, $12 in a mild winter, and $116 during a severe winter where natural gas supply is constrained relative to demand. A typical small business would have saved about $622 per winter.

TABLE

Segment	Gas total	Electric total	Gas accounts	Electric accounts	Gas $/acct	Electric $/acct	Combined $/acct	Beacon Cost to Consumer	Net Benefit $/acct
Residential	$115.4M	$68.2M	1,604,279	2,924,535	**$72**	**$23**	**$95**	**$19**	**$76**
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Table 1 based on model estimates and EIA gas and electric accounts.[9,10]

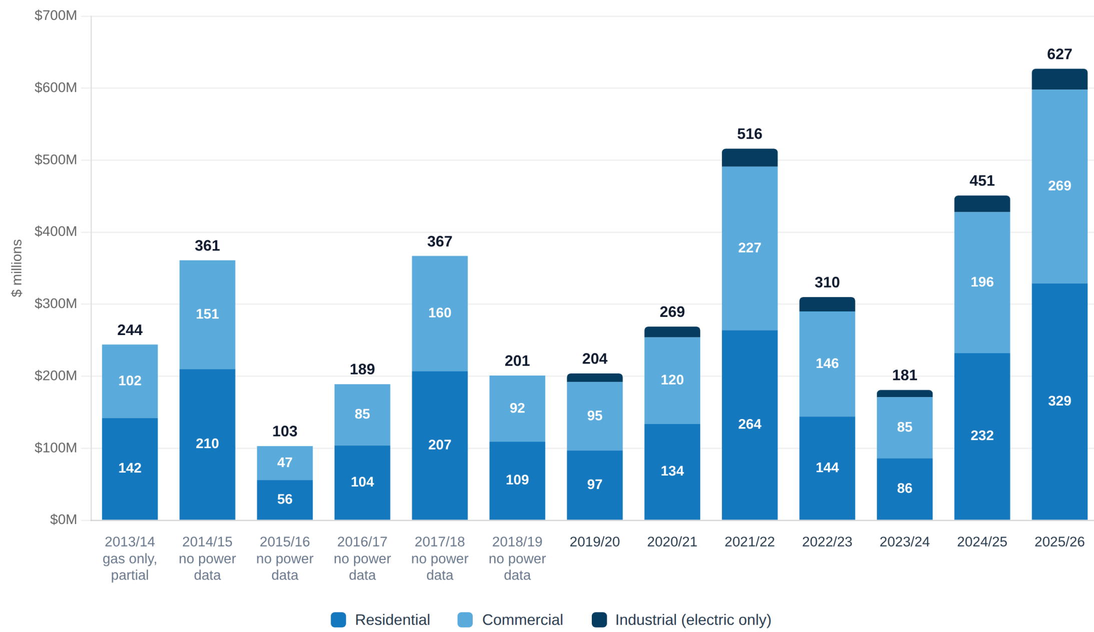
A note to the reader regarding these estimates. Estimates based on the econometric approach in the Appendix should not be construed as pure causality but rather as empirical estimates. This report does not establish causality but presents statistical results based on historical data. Generating causal results would require econometric techniques beyond the scope of this report. Second, estimates for winter 2026 should be interpreted only as illustrative results because the storm caused freeze-offs in natural gas production, a phenomenon in which the cold halts production. The production stoppage coincided with a sharp uptick in heating demand due to the extreme cold during the storm, leading to higher Algonquin Citygate and power prices across Massachusetts.

9 *EIA*
10 *EIA*

FIGURE 1

Total Estimated Massachusetts Ratepayer Savings (2013–2026)

Total Massachusetts ratepayer savings from +300 MMcf/d · Gas and electric bills combined, by customer class · Nov–Mar winter seasons · $ millions · pass-through 1.00



Each class combines its gas-bill and electric-bill saving. Generator fuel cost is excluded (it sits inside the wholesale power price, not on a bill) and so is oil displacement (a production cost). Industrial covers electricity only — industrial gas customers are typically transport-only and buy their own gas; including them would add about $30M per winter. Electric savings begin Nov 2019, so earlier bars are gas-only. Strictly comparable winters are 2019/20 onward; 2013/14 covers Feb–Mar 2014 only.

Source: Always On Energy Research, EIA, ISO-NE, S&P CapIQ.

In a typical winter, Massachusetts consumes an average of 1.8 Bcf per day (up to 4.9 Bcf per day) of natural gas during peak months.[11] During the extreme cold, such as Winter Storm Fern, demand for natural gas rises while pipeline capacity becomes constrained. This can lead to natural gas and wholesale electricity prices rising quickly. When pipeline gas becomes unavailable or more expensive than fuel oil, dual-fuel power plants switch from natural gas to distillate fuel oil—essentially diesel—to continue generating electricity. New England also relies on imported liquefied natural gas (LNG) to supplement pipeline gas, although LNG generally supplies a smaller share of the region's overall energy needs. Project Beacon would have reduced reliance on both of these more expensive fuels by delivering additional pipeline gas into the region. During this time, power prices–which are set by the load-distribution companies–must respond to both the increase in electricity demand from homes and businesses, as well as rising fuel prices.

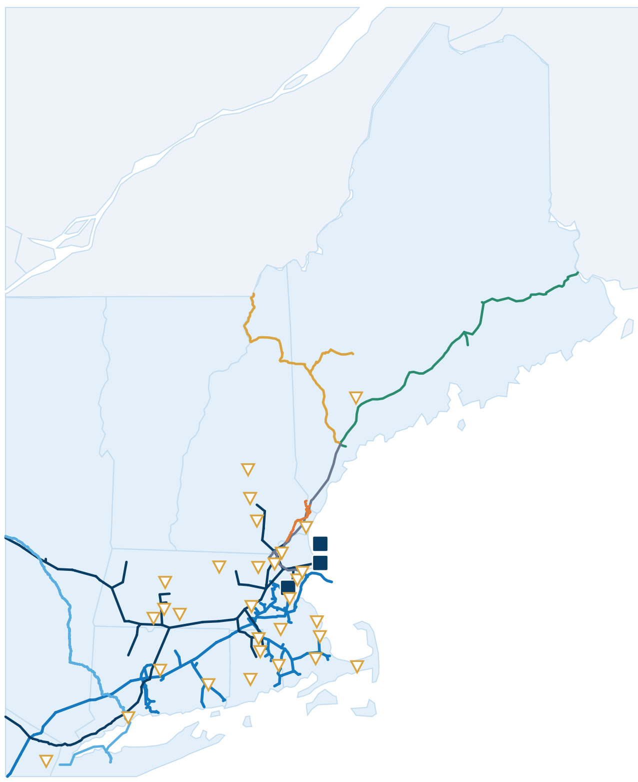
11 *ISO-NE*

Background

Availability of Natural Gas in Massachusetts & Power Prices

FIGURE 2

Map of Northeastern US Pipeline Systems



Algonquin | Tennessee | Iroquois | M&N | PNGTS | M&N/PNGTS Joint Facilities | Granite State | LNG Import Terminal | LNG Satellite Tank

Map data: EIA Natural Gas Interstate and Intrastate Pipelines; EIA / FERC LNG terminal and peak-shaving plant locations; U.S. Census Bureau and Natural Earth boundaries.

Source: Eastern Interconnection Planning Cooperative & Energy Dynamics.[12]

Natural gas pipeline constraints are one of many challenges Massachusetts faces amid rising energy prices. Academic evidence indicates that pipeline capacity constraints can lead to higher prices. In Marks et al. (2017) of Resources for the Future, for instance, the authors estimate that the withholding of 50 MMcf per day worth of capacity led to a 38% ($1.68/MMBtu) increase in average natural gas prices, and a 68% ($3.82/MMBtu) increase during winter months.[13] These

12 *Energy Dynamics*

13 *Resources for the Future*

estimates should be understood in the context of deliberate pipeline withholding, whereby gas scheduling firms were found to withhold natural gas, rather than as a result of pure physical capacity constraints. Nevertheless, the observation helps policymakers and business leaders understand the relationship between pipeline flows and prices.

Massachusetts and the broader Northeast rely on natural gas from the Appalachian basins via midstream networks, such as the Millennium Pipeline, before it reaches receipt points like Ramapo and enters the AGT system. These flows, however, are relatively limited because of existing infrastructure constraints. One way to understand this is to compare the average price of natural gas at the Pennsylvania Citygate to the Algonquin Citygate price. In 2024, for instance, the average price in Pennsylvania–which produces natural gas from the Marcellus region–was $4.61 per thousand cubic feet, and $7.43 per thousand cubic feet in Massachusetts, illustrating the price difference between a supply region and a demand region.[14]

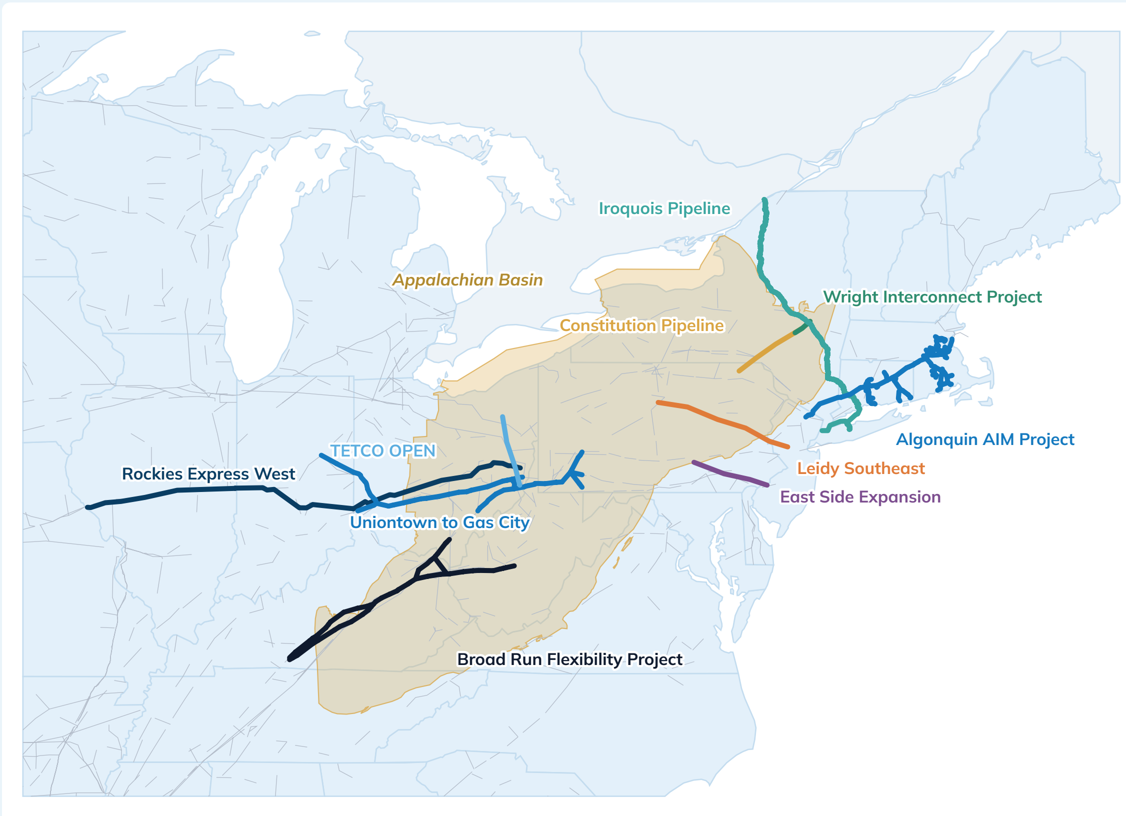
The deliverability of natural gas into New England is not necessarily limited by interconnects but rather by downstream capacity constraints at compressor stations, such as the Stony Point compressor station in New York.[15] Serving as a primary compressor station for eastbound volumes, Stony Point routinely reaches maximum capacity during winter peak demand, when power generators and firm residential heating customers compete for limited throughput. Once this station is fully constrained, fewer additional volumes of natural gas will enter Massachusetts. This creates unmet fuel demand for power generation and drives sharp price spikes at the Algonquin Citygate–a core challenge that Project Beacon aims to address.

14 *EIA*

15 *FactSet*

FIGURE 3

Map of Pipeline Expansion Projects in Northeastern US



Rockies Express West | Uniontown to Gas City | TETCO OPEN | Broad Run Flexibility Project
Leidy Southeast | East Side Expansion | Constitution Pipeline | Wright Interconnect Project
Iroquois Pipeline | Algonquin AIM Project | Appalachian Basin | Existing interstate pipelines

Map data: EIA Natural Gas Interstate and Intrastate Pipelines and EIA sedimentary basins; U.S. Census Bureau and Natural Earth boundaries. Expansion projects are shown along their host systems; Constitution, Wright Interconnect, Leidy Southeast, East Side Expansion and TETCO OPEN are approximate routes.

Source: EIA.[16]

Natural gas prices directly feed into electricity prices. In Linn, Muehlenbachs, and Wang (2014), the authors estimate that the pass-through of natural gas to electricity prices has an elasticity of 0.94 during off-peak hours and 0.96 during peak hours.[17] Broadly speaking, this implies that a 1% increase in natural gas prices translates to a 0.94% to 0.96% increase in electricity prices. For the state of Massachusetts, this elasticity is significant because of its reliance on natural gas for electricity production and, moreover, is a helpful heuristic for understanding why infrastructure projects such as Beacon are important. By supporting the flow of natural gas, both the price of

16 *EIA*

17 *Journal of Environmental Economics and Management*

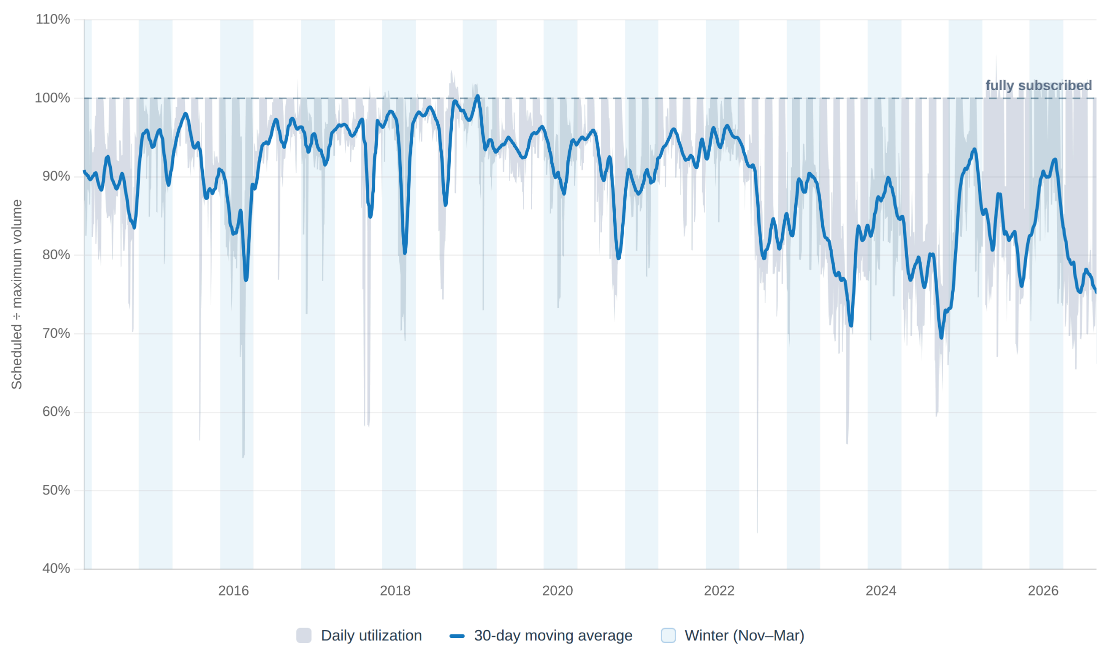
natural gas and electricity could decline in nominal terms, bringing along savings for everyday ratepayers.

Adding more capacity to the AGT could help reduce pipeline constraints during peak-demand days, which are generally when winter price spikes occur. This is due to the nature of commodity prices when demand increases and supply is limited, or when demand unexpectedly rises. As a result, natural gas prices can double in a matter of hours, a phenomenon known as convexity. In mild periods such as the fall and spring, pipeline capacity is generally not fully utilized. Figure 4 shows the Stony Point compressor Station daily scheduled volume utilization rate, which is one indicator of conditions across the AGT system.[18] During winter, the compressor's utilization rate eclipses 100% and remains elevated as heating and electricity demand surge, then declines as the weather warms. Scheduled volumes can surpass 100% of capacity utilization due to interruptible gas delivery contracts.

FIGURE 4

Stony Point Scheduled Utilization (2014–2026)

Stony Point utilization, 2014–2026 · Scheduled volumes as a share of maximum available capacity · daily, with a 30-day moving average



Utilization is scheduled volume divided by the maximum volume reported for that day. Values above 100% reflect days when scheduled nominations exceeded the reported maximum.

Source: S&P CapIQ, Always On Energy Research.

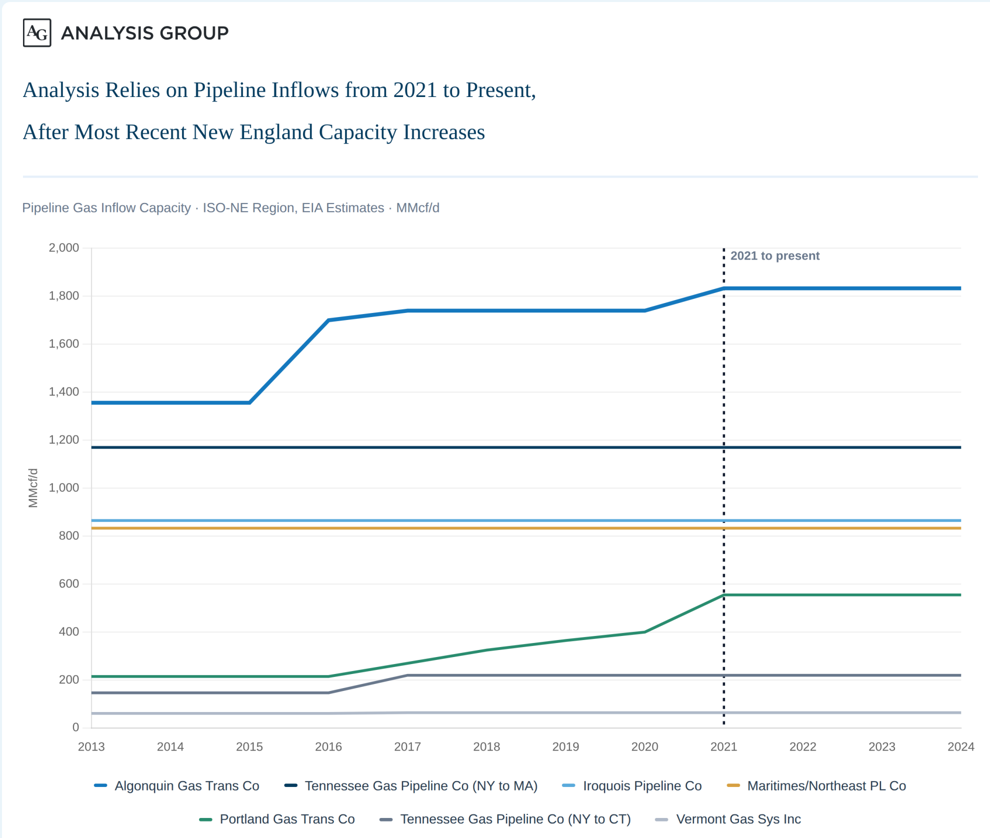
18 ***FactSet***

Project Beacon

Project Beacon is an Enbridge-led brownfield project that will add 300 million cubic feet per day (MMcf/d) of firm natural gas transmission capacity to the AGT by replacing smaller-diameter pipes with larger-diameter pipes, extending pipeline loops parallel to existing facilities, and adding additional compression at existing stations. These additions could help with capacity constraints at the Ramapo interconnect and Stony Point compressor station.

Firm service would run from the Ramapo receipt point at the Millennium Pipeline interconnect, and other in-path receipt points, to all existing delivery meters on the mainline and lateral systems, with a target in-service date as early as November 2030. Enbridge has also offered a separate flexible in-region storage service, contracted on an hourly and daily basis, primarily intended to meet gas-fired generators' ramping requirements.

The project's additional 300 MMcf/d of capacity (a 10% increase in nameplate capacity) would add much-needed natural gas capacity along the AGT, which serves the Boston-area citygate, which has seen few capacity additions over the last decade despite rising demand. In 2016, the Algonquin Incremental Market project brought online an additional 342 MMcf/d of capacity–the first project since 2007. Additionally, a smaller expansion of 133 MMcf/d, dubbed the Atlantic Bridge project, brought the AGT nameplate capacity to ~1,800 MMcf/d. While important pipeline expansions have occurred, Massachusetts has continued to face high energy prices.



Source: Analysis Group, Analysis of Winter Supplies from Gas-Fired Generators (ISO-NE, November 13, 2025), via RTO Insider.

Massachusetts will likely face rising electricity consumption due to its long-term decarbonization targets.[19] Over the next decade, ISO-NE forecasts that annual energy needs will rise from 94 GWh to 3,333 in 2035 for heating, and from 90 GWh in the transportation sector to 3,381 GWh.[20] As electricity demand grows, the natural gas system will require more capacity to import natural gas from neighboring states.

In 2022, for instance, the U.S. Energy Information Administration pointed out that pipeline constraints resulted in power plants resorting to fuel oil to generate electricity.[21] In total, 3,955 MW, or ~60%, of natural gas-fired electricity nameplate capacity is connected directly to the AGT–out of 6,602 MW of total natural gas nameplate capacity–leaving Massachusetts heavily reliant on the AGT for power generation.[22]

19 See Always on Energy Research's Massachusetts state energy ***profile*** for a comprehensive overview

20 ISO-NE 2026 CELT ***report***

21 ***EIA***

22 Based on Always On Energy Research analysis of ISO-NE data

How do natural gas pipeline flows affect prices?

New England's wholesale natural gas price consists of the national benchmark price (Henry Hub) plus a regional premium, known as the basis, that reflects the cost of delivering gas into the region—often varying with weather and local supply-and-demand dynamics. One way to understand how pipeline capacity—the amount of gas a pipeline can carry—affects prices is through statistical analysis. Natural gas prices exhibit convexity: during normal times, prices remain close to the national average, and during periods of acute stress, prices can rise dramatically (Figure 5).

To measure the relationship between pipeline utilization and Algonquin natural gas prices, this paper leverages a threshold regression following Hansen (2000). The analysis determined that the pipeline compressor station utilization rate of 89% was most closely associated with large price swings. Figure 6 plots the scheduled deliveries of natural gas along the AGT in addition to nameplate capacity and Algonquin Citygate prices. The sudden spikes in natural gas prices are generally centered to the right, rising to over $100/MMbtu in some cases. Next, the relationship between pipeline utilization and prices is nonlinear, as shown in Figure 6. It illustrates the relationship between the regional gas premium (basis) and pipeline utilization at the Stony Point compressor station from 2015 to 2026. Basis prices and pipeline utilization are weakly positively correlated and appear to be observationally normally distributed. During periods of pipeline congestion—peak winter, for instance—high pipeline capacity utilization is associated with higher prices, but the data are right-skewed, meaning a few observations have very high prices. Using our model estimates, we find that prices are generally stable until capacity utilization reaches about 89%, after which prices become more volatile and rise. This, in part, explains the winter price spikes the residents of Massachusetts so often face.

FIGURE 5

Algonquin Gas Transmission Scheduled Deliveries & Algonquin Citygate Prices

Daily, 2013–2026 · throughput in MMDth/d against pipeline capacity; basis in $/MMBtu

AGT Scheduled deliveries vs capacity

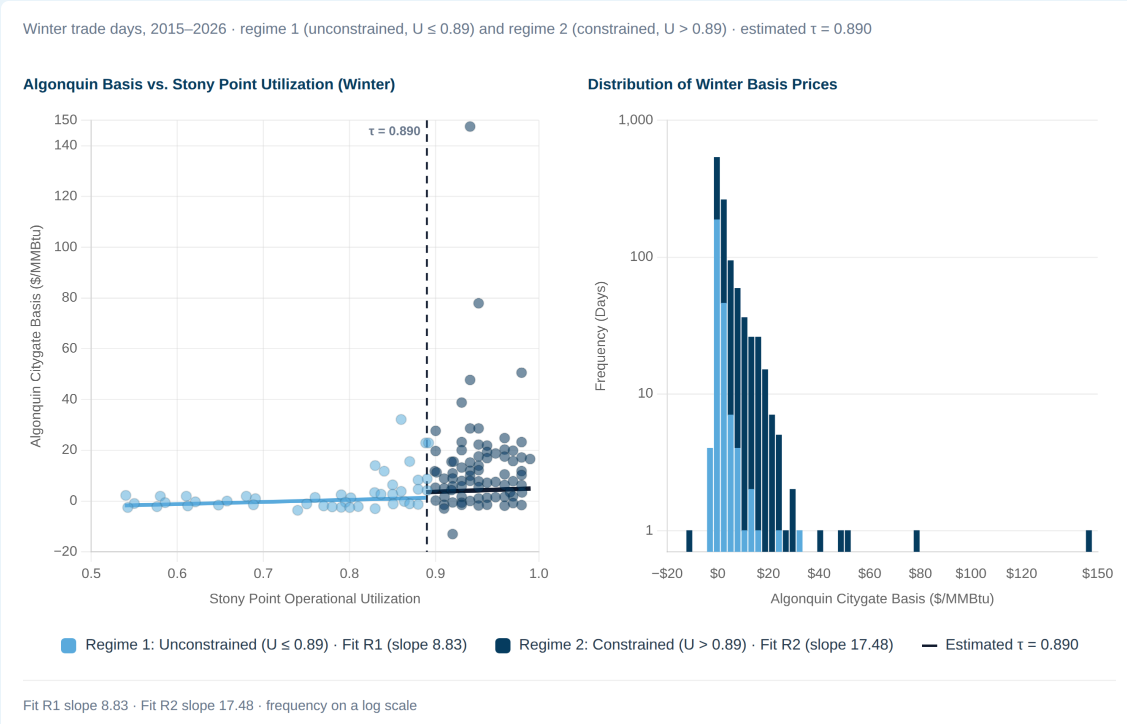
Algonquin Citygate − Henry Hub

Daily range · Scheduled deliveries · basis · Capacity

Source: S&P CapIQ, Always On Energy Research.

FIGURE 6

Winter Gas Premium vs. Pipeline Utilization (2015–2026)



Source: Always On Energy Research and S&P CapIQ.

Algonquin gas prices often exhibit extreme volatility because of pipeline constraints. When utilization of the Algonquin system's key constraint point exceeds roughly 89% of operational capacity, prices decouple from national benchmarks. This also corroborates EIA commentary from 2013.[23] Below the 89% threshold, New England gas trades within about $0.85/MMBtu of Henry Hub; above it, the premium averages $3.90/MMBtu–and the region spent roughly three-quarters of its winter days above the threshold. This is the cost of pipeline congestion, which falls on households and businesses as higher heating and electricity bills because gas-fired plants set the marginal electricity price in most winter hours.

These estimates are not used in the savings portion of our report but illustrate the relationship between natural gas prices and pipeline capacity in Massachusetts.

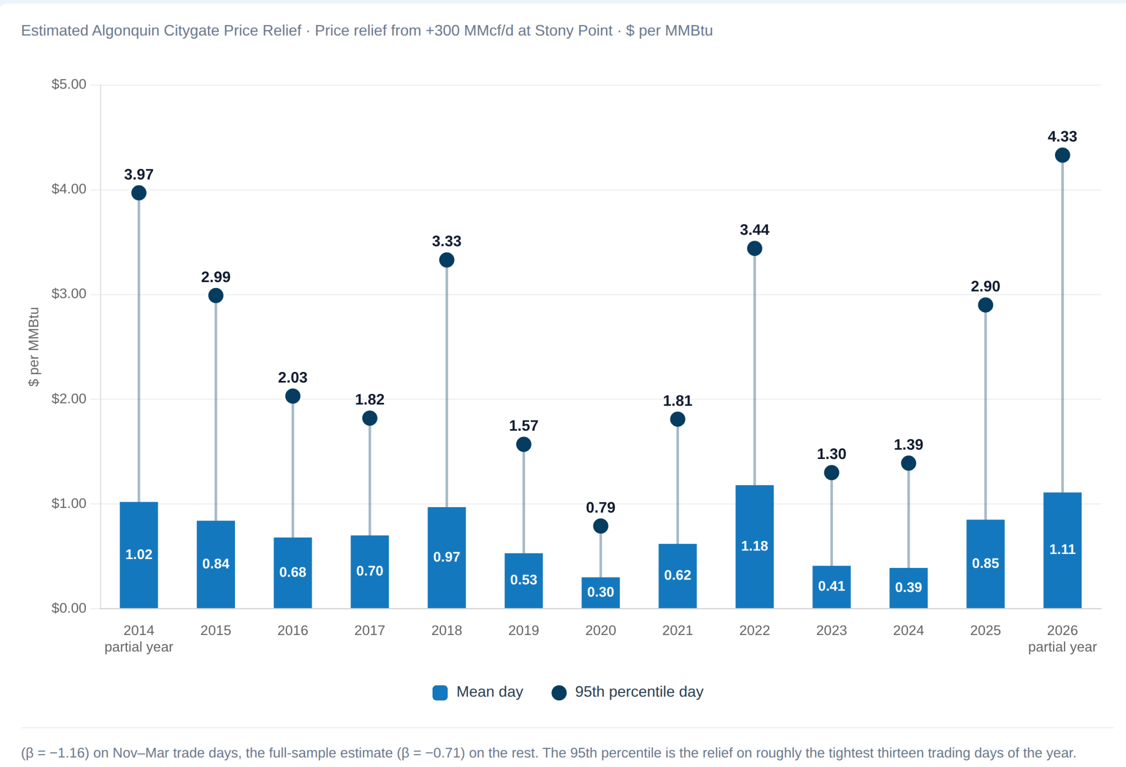
23 *EIA*

How could Project Beacon impact Algonquin Citygate prices and Massachusetts power prices, and how much could it save?

Adding natural gas pipeline capacity to the constrained New England market could deliver price relief, but the savings occur mostly during extreme weather events. For a 300 MMcf/d capacity addition like Project Beacon, we estimate an average reduction of $1.27/MMBtu in Algonquin Citygate prices, resulting in approximately $230 million in annual winter savings. However, the value of a pipeline expansion is centered on peak days rather than the average day, reflecting the nature of natural gas prices and their relationship to pipeline capacity, as discussed in the previous section. During the coldest 95th percentile of winter days (estimated by heating degree days), when the system is most constrained, the price relief from Project Beacon can reach an average of $3.97/MMBtu. More broadly, for every 1% increase in capacity, the citygate price falls by 0.71% on average days and by 1.16% in winter (see Appendix for details on the methodology).

FIGURE 7

Estimated Algonquin Citygate Price Relief from +300 MMcf/d Capacity Addition



Source: Model estimates.

The relief from natural gas passes through into electricity–as established by Linn, Muehlenbachs, and Wang (2014)–where gas sets the marginal price in most hours. A 1% fall in the citygate takes 0.74% off the Massachusetts wholesale price, so a 300 MMcf/d addition lowers winter power prices by an average of $4.78/MWh. This results in approximately $166 million per winter on Massachusetts electric bills, split into $68 million residential, $77 million commercial, and $19 million industrial. In the coldest 5% of winter weeks, relief reaches $11.39/MWh, and the composite elasticity is 0.85%: for every 1% of added capacity, the Massachusetts wholesale price falls 0.85% in winter, against 0.51% year-round.

The third channel is fuel displacement. Oil is New England's fuel of last resort, dispatched only when gas is scarce and expensive, and when prices reach parity with Algonquin Citygate prices. The response is elastic: for every 1% of added capacity, Massachusetts oil-fired generation falls 2.47% in winter–a 300 MMcf/d addition would cut winter oil burn by roughly 35%, some 80,500 MWh or 8.4 million gallons of fuel oil per winter. Valued at the observed oil-to-gas production cost spread, which averages $145/MWh, that is approximately $6.7 million per winter. During a mild winter, displacing fuel oil could lower costs by $1.2 million, and by as much as $13.1 million during an extreme winter.

This modeling approach, however, is limited in its ability to capture extreme events such as Winter Storm Fern, in which extreme cold led to a surge in heating demand and caused freeze-offs, as previously mentioned. Future iterations of this model could incorporate such conditions.

Lastly, Project Beacon's Open Season Notice states that the system "continues to operate at or near full utilization relative to its available west-end capacity" and that persistent constraints "drive sustained basis differentials between New England and upstream production areas." The policy question is therefore not whether pipeline scarcity costs New England consumers money – it demonstrably does, every winter–but whether the region prefers to keep paying for peak prices during the winter or to invest in the new pipeline capacity that reduces it.[24]

Historical comparison with the 2016 AIM capacity expansion

The 2016 AIM expansion is a recent benchmark we can use to evaluate our model. Applying the winter elasticity to AIM's 342 MMcf/d against the pre-AIM Stony Point base–a 23% capacity increase–implies a 23% reduction in the winter citygate price, roughly $1.46/MMBtu at pre-AIM winter price levels and $3.97/MMBtu on days when supply and capacity are scarce. Observed winter basis fell $3.04/MMBtu between the five winters before AIM and the five after ($5.14 to $2.09), against a Henry Hub decline of only $0.29. The estimated decline in basis prices remains consistent with the results for Project Beacon. These estimates are, however, heavily influenced by the 2013/2014 polar vortex. Excluding that single winter, the observed decline is $1.50/MMBtu on winter days, on average.

24 Enbridge, 2026

Retail pass-through to household bills

Wholesale commodity costs make up roughly one-third to one-half of a winter residential energy bill, with distribution and other utility charges accounting for the rest. We assume these cost reductions are fully passed on to customers–a long-run assumption, since utilities pass wholesale costs through with a lag.

In aggregate, Massachusetts residential customers would have saved approximately $184 million per winter–$115 million on gas bills and $68 million on electricity. Spread across the state's 1.6 million residential gas accounts and 2.9 million residential electric accounts, that is $72 per gas account and $23 per electric account, or roughly $95 per winter for a gas-heated household that also buys its electricity from the grid. A household heating with oil or electricity captures only the electric portion.

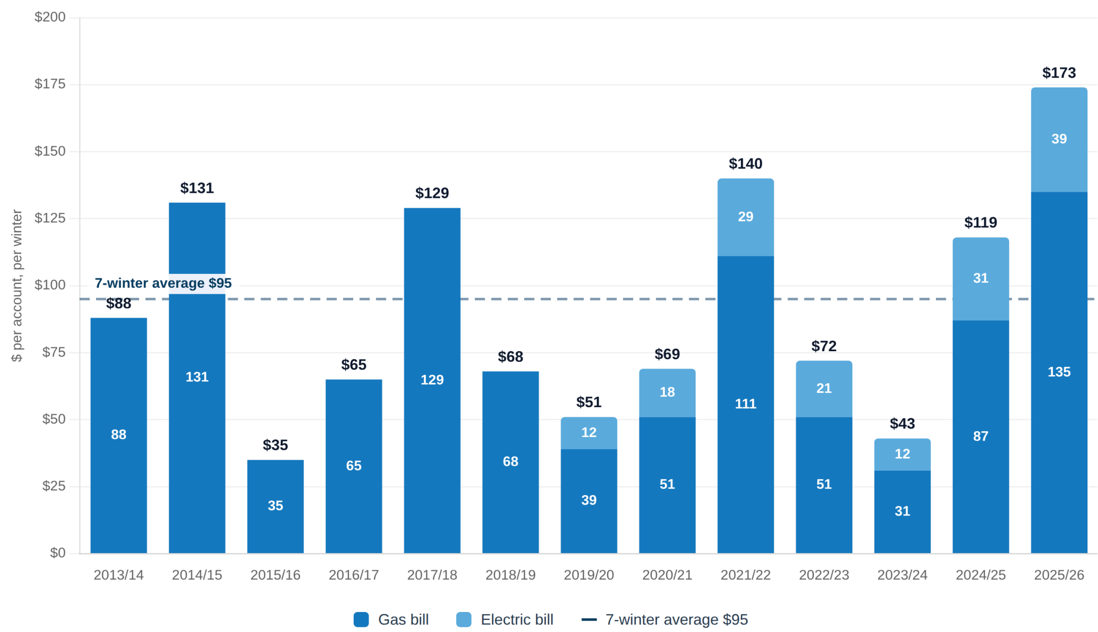
A typical residential account consumes about 56 MMBtu of gas and 2,900 kWh of electricity between November and March, so these figures reflect a winter citygate reduction of $1.28/MMBtu and a wholesale power price reduction of $4.78/MWh.

The averages understate the value of capacity when the system is tight. In the mild winter of 2023–24, a gas-heated household would have saved $43. In 2025–26, when Winter Storm Fern drove the region's constraint premium to record levels, the same household would have saved $173 — four times as much, and nearly double the seven-winter average (Figure 8).

FIGURE 8

Residential Customer Account Savings per Winter (2013–2026)

What a gas-heated household would have saved · Massachusetts residential accounts · savings per winter from +300 MMcf/d · full pass-through



Gas savings are spread across 1,604,279 residential gas accounts, electric savings across 2,924,535 residential electric accounts. Only a household that heats with gas AND buys grid electricity collects both segments; a home on oil or electric heat sees the electric bar alone. A typical account uses about 56 MMBtu of gas and 2,900 kWh over Nov–Mar. Electric savings begin Nov 2019, so earlier bars are gas only.

Source: Always On Energy Research, S&P CapIQ, ISO-NE, EIA.

Who will pay for Project Beacon?

Measuring the ratepayer impact of Project Beacon remains difficult to estimate precisely. Enbridge builds and owns the pipeline, but Massachusetts households pay for it.[25,26] The company recovers its capital through fixed monthly reservation charges on the utilities that sign up for the capacity – a charge owed on the space reserved, not the gas actually delivered, twelve months a year for the life of the contract.[27] Those utilities in turn recover the charge from customers through the Cost of Gas Adjustment Clause, which spreads it across everyone who buys gas from them.[28]

25 *FERC*

26 *FERC*

27 *Congressional Research Service*

28 *Mass*.gov

To estimate Project Beacon's cost, we start with public reporting on Enbridge's smaller Algonquin expansion: roughly $300 million to add about 75 MMcf/d of capacity, or about $4 million per MMcf/d.[29] Beacon is expected to add 300 MMcf/d – about four times that project – implying a capital cost near $1.2 billion. Enbridge recovers that capital through fixed monthly charges on the utilities that contract for the new capacity, and a standard FERC cost of service runs about 13 percent of capital per year, or roughly $156 million annually. Massachusetts pays in proportion to the capacity its utilities subscribe to; at an estimated 40% share, and after credits for capacity released in the shoulder months, about $53 million a year (or ~15%) reaches Massachusetts gas customers. That cost is spread across firm gas sales by volume rather than by customer count, which works out to 2.4 cents per therm – about $19 a year for the average residential account and $170 for the average commercial account. Industrial customers, who largely buy their own gas and simply transport it on the pipeline, fall outside this allocation.

Conclusion

Project Beacon represents an important step in the right direction to address the chronic pipeline constraints that have long plagued Massachusetts ratepayers with high and volatile energy costs. By expanding the firm natural gas transmission capacity by 300 MMcf/d, this infrastructure upgrade would directly alleviate supply bottlenecks during peak winter demand, effectively dampening volatility in natural gas and wholesale electricity prices. While the Commonwealth's ratepayers ultimately bear the project's capital costs, our analysis shows that the cumulative economic benefits–including average residential savings of $76 per winter, significant relief for commercial and industrial users, and the displacement of more expensive fuel oil – outweigh these costs. Ultimately, Project Beacon provides a clear pathway to enhanced energy security in Massachusetts, delivering net economic value to households and businesses by mitigating the most pernicious spikes in winter energy prices.

29 *Wbur*.org

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Methodological Appendix

This appendix documents the data and econometric approach for this report. We attempt to estimate three key relationships to build our total savings for Massachusetts: pipeline capacity and the Algonquin citygate gas price; the gas price and the Massachusetts wholesale power price; and the price of natural gas relative to oil-fired dispatch. We estimate every parameter with heteroskedasticity- and autocorrelation-consistent (HAC) standard errors, using a Bartlett kernel with a data-selected bandwidth (Andrews, 1991).

1. Data

Series	Frequency	Date Range	Use in estimation	Source
Stony Point and Ramapo scheduled volumes, available volumes, and reported maximum volume (Dth/d)	Daily	2011-01-06 – 2026-09-05 (Stony Point from 2014-02-14)	Capacity K_t and scheduled flow Q_t in (1)	S&P CapIQ
Algonquin Citygate and Henry Hub spot indices ($/MMBtu)	Daily, trade days	2005-01-03 – 2026-07-24	Dependent variable and upstream control in (1)	S&P CapIQ
Zonal and MA-average day-ahead and real-time LMPs, on / off / all hours ($/MWh)	Weekly averages	2019-06-03 – 2026-08-24	Dependent variable in (2), MA_AVG_RT_AllHours	ISO-NE
MA net generation by fuel — all fuels, natural gas, petroleum liquids (thousand MWh)	Monthly	2001-01 – 2026-04	Dependent variable in (3)	EIA
MA retail electricity sales by sector — residential, commercial, industrial, transportation, other (million kWh)	Monthly	2001-01 – 2026-06	Load L in (2)–(3)	EIA
Natural gas deliveries to MA electric power companies (MMcf)	Monthly	2001-01 – 2026-06	Generator gas volumes in the wholesale distribution	EIA
MA natural gas deliveries by end use (residential, commercial, industrial, vehicle, electric power), (MMcf)	Monthly	1989-01 – 2026-06	LDC volumes (5)	EIA
MA wholesale heating oil price ($/gal)	Weekly, heating season (Oct–Mar) only	2013-10-07 – 2026-03-30 (343 obs.)	Cross-fuel substitution control in eq. (3), converted to $/MMBtu and averaged to monthly	EIA
TMAX / TMIN for a four-station New England composite	Daily	1936-01-01 – 2026-08-27	(1) - (3)	NOAA

2. Econometric Framework

We develop three models that build on previous estimates to incorporate the effects of natural gas, electricity, and fuel oil. We estimate each model across the full data set and then in the winter (November-March) subsample to isolate Project Beacon's potential impact on Massachusetts.

2.1 Capacity elasticity of the citygate price

(1) estimates the elasticity of the local citygate price relative to the Stony Point compressor station capacity:

$$\log P^{AGT}{}_t = \alpha + \theta \log P^{HH}{}_t + \beta \log K_t + \delta \log Q_t + \gamma \log(1 + HDD_t) + \boldsymbol{X}_t\Phi + \varepsilon_{1,t} \quad (1)$$

where $P^{AGT}{}_t$ is the Algonquin Citygate spot price, $P^{HH}{}_t$ the Henry Hub national benchmark, K_t the reported maximum Stony Point capacity, and Q_t the scheduled flow (both in Dth/d), and $\boldsymbol{X}_t$ a matrix of month and year fixed effects (seasonal controls). The parameter of interest is $\beta \equiv \partial \log P^{AGT} / \partial \log K$.

Estimation is in log levels rather than first differences because Beacon is a permanent level shift in capacity, whereas a differenced specification identifies the response to a transitory change. We estimate these regressions with HAC standard errors to account for this.

Capacity and scheduled flow enter separately because Project Beacon changes *capacity*, and capacity variation is driven largely by maintenance and outage scheduling and is more plausibly exogenous to the local price than demand-driven variation in flow.

2.2 Pass-through to wholesale power

Next (2) predicts the price of the average real-time power price across Massachusetts, where the goal is to estimate the change in power prices relative to the change in pipeline capacity:

$$\log P^{RT}{}_w = \alpha + \varphi \log P^{AGT}{}_w + \lambda \log L_w + \gamma \log(1 + HDD_w) + \boldsymbol{X}_w\Phi + \varepsilon_{2,w} \quad (2)$$

(2) is estimated on weekly averages due to data availability, where $P^{RT}{}_w$ is the Massachusetts average real-time all-hours locational marginal price, and L_w is Massachusetts retail electricity sales. Similar to (1), $\boldsymbol{X}_w$ is a matrix of temporal and seasonal controls. The elasticity of power prices with respect to pipeline capacity is $\partial \log P^{RT} / \partial \log K = \varphi\beta$.

2.3 Oil displacement

Lastly, (3) estimates monthly fuel oil generation. Fuel oil is the fuel of last resort in New England winters. The response of oil-fired dispatch to the citygate gas price is estimated controlling for the price of wholesale heating oil:

$$\log(G^{oil}{}_m) = \alpha + \psi \log P^{AGT}{}_m + \xi \log P^{oil}{}_m + \lambda \log L_m + \gamma \log(1 + HDD_m) + M_m\Phi + \tau t + \varepsilon_{3,m} \quad (3)$$

M_m carries monthly fixed effects and τt is a linear trend that absorbs the structural retirement of the New England oil fleet–a common specification used in time series econometrics.

Merit-order switching is a claim about relative prices, indicating that if oil-fired units simply burn whichever fuel is cheaper per MMBtu, then only the gas-oil ratio should drive substitution, and a rise in the gas price should move oil generation by exactly the same amount as an equivalent fall in the oil price. That symmetry is testable, and the data reject it ($p = 0.0013$). A 10% increase in the citygate price is associated with roughly 21% more petroleum burn; a 10% decline in the oil price buys about 10% more. Oil generation responds to gas scarcity at twice the rate it responds to oil prices—suggesting that variation in oil generation is more sensitive to natural gas prices rather than to oil prices.

2.4 Counterfactual construction and ratepayer incidence

To estimate a counterfactual change in natural gas prices relative to capacity, we multiply the observed price by the estimated capacity effect:

$$P^{AGT,cf}_{t} = P^{AGT}_{t} \cdot \exp\left(\beta \ln \left[(K_t + \Delta K) / K_t \right] \right) \quad (4)$$

Gas ratepayers pay the citygate price through the supply component of an LDC bill and electric ratepayers pay the wholesale power price through the supply component of an electricity bill:

$$\Delta S^{gas} = \Sigma_{m \in W} \left(P^{AGT}_{m} - P^{AGT,cf}_{m} \right) \cdot V^{LDC}_{m} \cdot \eta \quad (5)$$

$$\Delta S^{elec} = \Sigma_{m \in W} P^{RT}_{m} \left[1 - \exp\left(\varphi\beta \ln\left((K_m + \Delta K) / K_m \right) \right) \right] \cdot L_m \cdot \eta \quad (6)$$

where W is the set of winter months in a season, V^{LDC}_{m} is measured gas delivered to residential and commercial customers, L_m is measured Massachusetts retail electricity sales, and $\eta \in [0, 1]$ is the long-run pass-through of wholesale prices to retail tariffs.

3. Estimation Samples

Model	Frequency	Sample	N	R^2	Note
(1)	Daily	2014-02-14 – 2026-07-24	3,095	0.701	Stony Point data begin Feb 2014; the gas price series ends 24 Jul 2026
(1) winter	Daily	Nov–Mar within the same span	1,239	0.743	As above
(2)	Weekly	2019-06-03 – 2026-08-24	366	0.918	The ISO-NE weekly price series begins in June 2019
(2) winter	Weekly	Nov–Mar within the same span	149	0.941	As above
(3)	Monthly	2014-02 – 2026-04	144	0.594	Generation data end Apr 2026
(3) winter	Monthly	Nov–Mar, with the heating oil control	61	0.717	The heating oil survey covers Oct–Mar only — present in 62 of 62 winter months, against 82 of 147 year-round
Incidence panel	Monthly, winter	62 winter months, 2014-02 – 2026-03	—	—	Both channels complete in 7 winters, 2019/20 through 2025/26; earlier winters are gas-only

4. Estimated Parameters

Each reported coefficient is the elasticity of the dependent variable with respect to the driver. Standard errors are HAC with an Andrews (1991) data-selected Bartlett bandwidth.

Model	Sample	Parameter	Estimate	HAC s.e.	t	p	HAC lags
(1)	Full	β (log K)	−0.705	0.194	−3.64	0.0003	34
(1)	Winter	β (log K)	−1.156	0.485	−2.39	0.0171	18
(2)	Full	φ (log P AGT)	+0.718	0.030	+23.66	<0.0001	6
(2)	Winter	φ (log P AGT)	+0.737	0.046	+15.98	<0.0001	5
(3)	Full	ψ (log P AGT)	+1.091	0.264	+4.13	<0.0001	5
(3)	Winter	ψ (log P AGT)	+2.137	0.287	+7.45	<0.0001	4

Specification tests

Restriction	Sample	Statistic	p	Result
θ = 1 — does the model behave as a log-basis spread?	Full	1.820	0.177	Not rejected
θ = 1	Winter	0.147	0.702	Not rejected
β(log K) = −β(log Q) — is utilization a valid restriction?	Full	0.277	0.599	Not rejected
β(log K) = −β(log Q)	Winter	1.359	0.244	Not rejected
ψ = −ξ — is oil dispatch symmetric?	Winter	10.331	0.0013	REJECTED

5. Elasticities

Applying the winter parameters at winter mean prices to an average capacity of 1,609,537 Dth/d:

ΔK	Citygate, winter mean price	Citygate, winter p90 price	MA real-time power	MA oil burn
+100 MMcf/d	−$0.46 / MMBtu	−$1.00 / MMBtu	−$2.90 / MWh	−13.9%
+300 MMcf/d (Beacon)	−$1.23 / MMBtu	−$2.66 / MMBtu	−$7.94 / MWh	−34.5%

Composite winter elasticities with respect to capacity: citygate −1.156, wholesale power −0.852, oil burn −2.471. The 95% confidence interval for the +300 MMcf/d citygate effect at winter-mean prices ranges from −$2.08 to −$0.24 per MMBtu. The year-round figures, at a sample mean citygate price of $4.53, are −$0.19 and −$0.52 per MMBtu.

Sensitivity of savings and pass-through assumptions

The per-winter total ranges from $181.6M in 2023/24 to $628.9M in 2025/26; the largest in the sample is the most recent, at $517.1M in 2021/22 and $452.8M in 2024/25. Six earlier winters (2013/14 through 2018/19) have only a gas component because the weekly power price series begins in June 2019.

Pass-through η	Gas customers $M	Electric customers $M	Ratepayer total $M
0.60	120.4	99.5	219.9
0.70	140.5	116.1	256.5
0.85	170.6	141.0	311.5
1.00 (reported)	**200.6**	**165.8**	**366.5**

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