COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

CLIMATE COMPLIANCE PLANS

D.P.U. 25-40 through D.P.U. 25-44/45

APPENDICES TO THE DIRECT TESTIMONY OF

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On behalf of

THE MASSACHUSETTS OFFICE OF THE ATTORNEY GENERAL

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I. APPENDIX A: The Energy Transition is Disrupting the Gas Utility Business Model

<u>Summary</u>

- Gas utilities primarily generate revenue by providing customers with access to a network of pipelines engineered to meet peak demand requirements.
- The business model is heavily reliant on spreading the significant fixed costs of building and maintaining gas infrastructure over a large customer base, as well as across peak and off-peak usage periods and the long asset life of the system.
- Recent trends show that both gas supply and distribution costs are increasing, driven by factors such as aging infrastructure, stricter safety standards, and rising labor expenses.
- These growing costs, coupled with the need to reduce gas consumption to meet climate targets and the emergence of competitive non-gas technologies, are challenging the traditional gas utility business model.
- As a result, gas utilities face greater difficulty in recovering their investments and maintaining affordability for customers in a shifting energy landscape.

<u>Policy Relevance</u>

Gas will never be as affordable as it is today. Policy makers cannot halt the increase in gas costs, which are heavily driven by rising infrastructure costs. Increasing customer choice will likely lead to declining demand, concentrating costs on remaining consumption and customers. Preserving affordability will require increasing management of gas investments and policy.

A. <u>The Gas Utility Business Model</u>

Investor-owned gas utilities build, finance, and operate networks of pipes that distribute natural gas to their customers. These customers, in turn, provide revenue for the utility based on regulated rates and each customer’s usage of the system. Generally, the system is designed to ensure that every customer’s energy needs are adequately met, adhering to safety and reliability standards. Investments and operations must be sufficient to meet these design requirements. Utility investors earn a rate of return on the capital invested upfront for these projects. This cost, plus investment depreciation expenses, applicable taxes, and operating expenses, contributes to the utility’s revenue requirement. This revenue requirement serves as the basis for rates charged to consumers. While gas utilities procure gas on behalf of their customers, the cost of gas supplied to this system is passed directly on to their customers.

In brief, gas utilities are in the business of selling access to pipes designed to meet peak gas demand needs. These pipes are a large, fixed cost. This business model depends on economies of scale, as gas distribution systems are large, fixed costs that are: (1) spread over many customers; (2) incurred to address peak demand yet recovered through consumption spread over the course of a year; and (3) spread over the lifetime of the asset (50+ years). This cost spreading has enabled gas utilities to historically grow and compete with other forms of heating.

In Massachusetts, gas utilities are regulated as natural monopolies, and their investments and rates are subject to oversight by the Department of Public Utilities ("Department") to ensure that spending is prudent and that each utility's practices conform to the public interest. Historically, investment in the gas system has aligned with the public interest by providing customers with access to more energy options. During the last decade, the breakthrough of hydraulic fracturing lowered gas supply costs. This attracted customers, allowing the utility to invest more in the system while spreading fixed costs over a larger customer base.

However, this paradigm is now being altered by three disruptors: (1) growing costs in both gas supply and distribution; (2) the need to reduce gas consumption to achieve climate targets; and (3) a growing set of competitive non-gas technologies that increase customer choice. The mechanism and consequences of these disruptors are discussed in more detail below; however, it is important to note that these disruptors increase the challenge of recovering costs invested in the system.

B. <u>Disruptions to the Investor-Owned Gas Utility Business Model</u>

1. Growing supply and distribution costs

Gas supply costs are undergoing a transition from a decade of technology-driven oversupply and associated low prices towards a period of demand growth and higher supply prices. The emergence of hydraulic fracturing technology enabled a remarkable decline in gas supply costs into the 2010s with respect to both the Henry Hub national benchmark and Massachusetts city gate prices (Figure 1 below).[1] By the second half of the 2010s, supply prices had dropped to 20-year lows. In the early 2020's, a confluence of factors led to a price spike.[2] While this was temporary, and followed by a period of low prices, increasing demand from data centers and LNG export terminals currently puts upward pressure on futures prices. This marks a new era of gas supply prices influenced more by demand and more tied to inflation.

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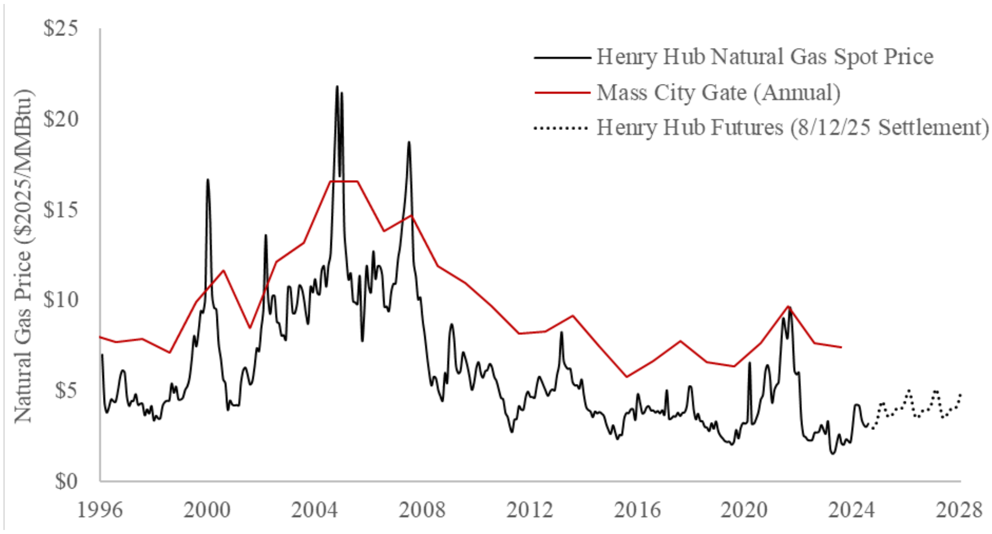
1 The difference between Massachusetts City Gate and Henry Hub prices can be partially attributed to regional market dynamics for natural gas.

2 Influencing factors included pandemic recovery, extreme weather events (Winter Storm Uri), coal-to-gas switching with coal retirements, increasing LNG exports tying the US gas market to the international market, and the Russian incursion into Ukraine.

Figure 1. Natural gas prices for Massachusetts City Gate (EIA, annualized),[3] Henry Hub (EIA, monthly)[4] and Henry Hub Futures (CME Group.)[5] Prices are converted to real 2025$.[6]



Gas system distribution investment costs have grown significantly due to aging infrastructure and stricter integrity standards, and are projected to continue to rise.[7] This increase has occurred in both absolute terms (Figure 2 below) and per-customer terms (Figure 3 below) at paces that exceed inflation. Statewide spending on gas infrastructure now exceeds statewide

3 U.S. Energy Information Administration ("EIA"), *Natural Gas Citygate Price in Massachusetts*, https://www.eia.gov/dnav/ng/hist/n3050ma3a.htm.

4 U.S. EIA, *Henry Hub Natural Gas Spot Prices*, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

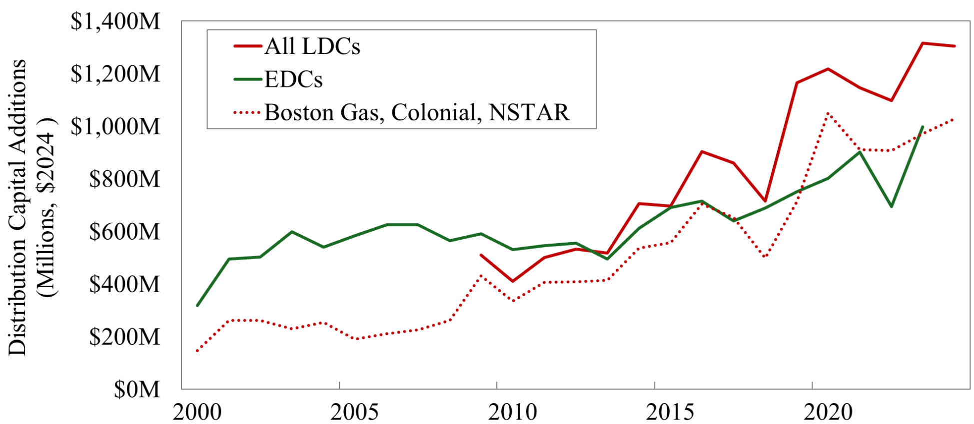
5 CME Group, *Henry Hub Natural Gas Futures – Settlements*, https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html.

6 Prices are converted to real 2025$ using a CPI deflator for Boston-Cambridge-Newton for Mass City Gate, and a national CPI deflator for Henry Hub. U.S. Bureau of Labor Statistics ("BLS"), *Consumer Price Index, Boston-Cambridge Newton*, https://www.bls.gov/regions/northeast/news-release/consumerpriceindex_boston.htm.

7 Data gathered from assessment of LDC Annual Returns for 2000-2024, https://www.mass.gov/info-details/find-a-natural-gas-company-annual-return.

spending on electric infrastructure, while per-customer gas investment in Massachusetts is more than double the national average.[8] Following the 2014 Gas Leaks Act, my analysis has shown that distribution spending skyrocketed in both absolute terms (7.87 percent compound annual growth above inflation) and per customer terms (7.61 percent compound annual growth above inflation). These increases are largely driven by the need to meet stricter pipeline integrity standards through the replacement of older pipe, compounded by escalating contractor and labor costs.

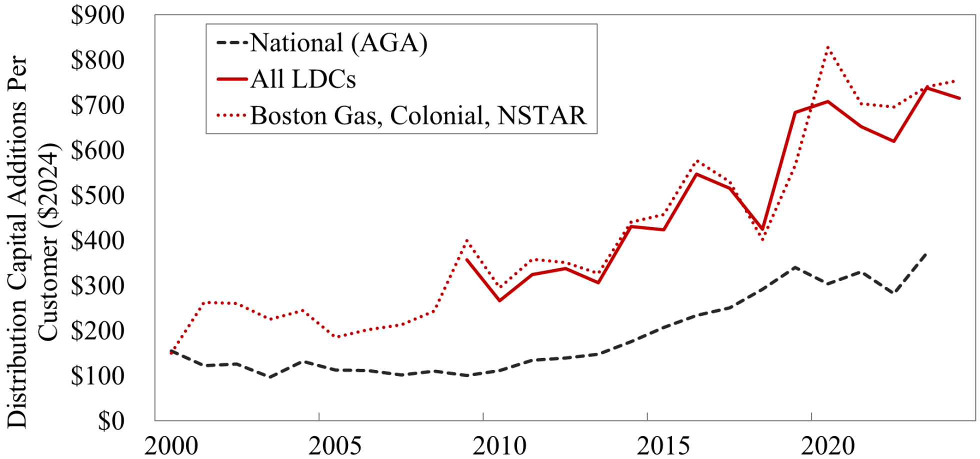
Figure 2. Distribution system spending for Massachusetts investor-owned local gas and electric distribution companies (LDCs and EDCs, respectively).[9]



8 AGA, Gas Utility Construction Capital Expenditure, Feb. 2025, https://www.aga.org/research-policy/resource-library/gas-utility-construction-capital-expenditure/.

9 LDC data was extracted from LDC annual returns filed with the Department (Page 18, column c), https://www.mass.gov/info-details/find-a-natural-gas-company-annual-return; Data prior to 2009 for Fitchburg, Columbia Gas of Massachusetts (now EGMA), and Berkshire were unavailable for this figure. EDC spending data was obtained from FERC Form 1, page 208 column c. Prices are converted to real 2024$ using a CPI deflator for Boston-Cambridge-Newton.

Figure 3. Per-customer distribution system spending for Massachusetts LDCs[10] alongside national averages using spending data reported by the American Gas Association,[11] and the AGA's aggregation of customer counts from EIA Form 176.[12]



Such trends in spending are expected to continue. The LDCs' *Assessment of Potential Gas LDC Capital Transition Costs*, which forecasted Capital Expenditures by Business Scenario (Figure 9 of Attachment 6 in each LDC's initial filing),[13] shows total investment needs of $1.5-$2.0 billion per year for the next two decades (which presumably includes capital expenditures in addition to the distribution plant). This assessment further illustrates that under all plausible ranges of customer departures—from none to substantial—per customer revenue requirements, rates, and bills will increase significantly. This analysis corroborates the findings presented in the 20-80

10 LDC data was extracted from LDC annual returns filed with the Department (page 18, column c and page 7 total customers). Data prior to 2009 for Fitchburg, Columbia Gas of Massachusetts (now EGMA), and Berkshire were unavailable for this figure. Prices are converted to real 2024$ using a CPI deflator for Boston-Cambridge-Newton. Groundwork Data analysis.

11 AGA, *Gas Utility Construction Capital Expenditure, Energy Insights*, Feb. 2025, https://www.aga.org/research-policy/resource-library/gas-utility-construction-capital-expenditure/.

12 U.S. EIA, *Natural Gas Annual Respondent Query System (EIA-176)*, https://www.eia.gov/naturalgas/ngqs.

13 *See, e.g.*, *National Grid*, D.P.U. 25-41, Exh. NG-CCP, Att. 6., at 56.

Independent Consultant Report,[14] as well as those presented by the AGO's witnesses during the 2024 Gas System Enhancement Plan ("GSEP") proceedings.[15] Simply put, gas will never be as affordable as it is today, a fact that undermines the core historical value proposition that underpinned efforts to expand gas.

2. Climate action

Climate action is disrupting the gas utility business model through federal, state, and municipal policies alongside voluntary, and often coordinated, actions by institutions and individuals. Federal policy is in flux, with efforts by the Trump Administration, via the One Big Beautiful Bill Act, to roll back provisions of the Inflation Reduction Act that would have provided tax credits and manufacturing support to electrification efforts. Despite significant rollbacks, some provisions, such as tax credits for commercial ground-source heat pumps, are expected to continue.

Massachusetts is a national leader in climate policy and action, engaging in numerous avenues of climate policy aimed at reducing gas consumption predominantly by creating structures for switching customers to electric alternatives (Table 1 below).

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14 Energy and Environmental Economics & Scott Madden Management Consultants, D.P.U. 20-80, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Part I Technical Analysis of Decarbonization Pathways* (Mar. 18, 2022).

15 24-GSEP-01 to 24-GSEP-06, Exh. AG-DL-DM-1, at 32.

Table 1. Major climate legislation in Massachusetts and its Implications for the Gas System.

Legislation	**Session Law**	**Relevance and implications for the gas system**
Global Warming Solutions Act (2008)	St. 2008, c. 298	• Requires 80 percent (relative to 1990) reduction in statewide GHG emissions by 2050 (§ 6) • Requires the Department of Environmental Protection to monitor and regulate GHGs (§ 6)
Green Communities Act (2008)	St. 2008, c. 169	• Establishes current overarching structure of Mass Save energy efficiency programs (§ 11) • Aligns building code with the International Energy Conservation Code and provisions the development of a more stringent stretch code (§ 55)
An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (2021)	St. 2021, c. 8	• Requires 85 percent (relative to 1990) reduction in statewide GHG emissions by 2050 and a 50 percent reduction by 2030 (§ 10) • Directs EEA to establish interim limits and sector-specific sub-limits based on quintennial planning (§ 8) • Requires the development of a "municipal opt-in specialized stretch energy code" that includes net-zero buildings performance standards (§ 31) • Directs the Department of Public Utilities to "prioritize safety, security, reliability of service, affordability, equity and reductions in greenhouse gas emissions" (§ 15)
An Act Driving Clean Energy and Offshore Wind (2022)	St. 2022, c. 179.	• Expanded GSEP-eligible projects to include advanced leak repair technology (§ 58) • Establishes Municipal Fossil Fuel Free Building Demonstration Program (§ 84)
An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers (2024)	St. 2024, c. 239	• Updates GSEP to allow for alternative infrastructure measures other than replacement and requires assessment of benefits, costs, and potential for stranded assets (§ 81) • Allows the Department to "vary the uniformity of the availability of natural gas service" to "advance the public interest in reducing greenhouse gas emissions" (§ 77)

Climate action is also evolving at the municipal and community levels. The Commonwealth allows municipalities to opt in to increasingly stringent tiers of building energy codes:[16] a high-performance "Stretch Code" and a "Specialized Code" that seeks to align new construction with the emissions limits and sublimits. Two hundred and forty-six municipalities (60.2 percent of the state's population) have adopted the high-performance "Stretch Code", while 55 municipalities (31.5 percent of the state's population) have adopted the new "Specialized

[16] 225 CMR § 22.00 (Residential); 225 CMR § 23.00 (Commercial).

Code", which seeks to align new construction with the State's emissions limits.[17] Additionally, a further ten of the Specialized Code Communities (6.1 percent of the state's population) are participating in the Department of Energy Resources' ("DOER") Municipal Fossil Fuel Free Building Demonstration Program , which allows municipalities to adopt fossil-fuel free building codes. Many of these towns coordinate outreach programs to promote the adoption of electric alternatives to gas in their communities, supported in part by the Green Communities Program.[18]

Boston's Building Emissions Reduction and Disclosure Ordinance sets a declining cap on emissions for large buildings and a compliance payment of $234 per ton CO_2 emitted over the limit.[19] A similar program in Cambridge has established declining emissions requirements for non-residential buildings.[20]

Many of Massachusetts' higher education institutions have made climate commitments aligned with, and in some cases exceeding, the State's emissions limits. A remarkable example of such action is the construction of a 19-story gas-free educational building on the Boston University campus that heats and cools using a ground-source heat pump.

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[17] DOER, *Building Energy Code Adoption by Municipality*, Aug. 18, 2025, https://www.mass.gov/doc/building-energy-code-adoption-by-municipality/download.

[18] DOER, Green Communities Division. https://www.mass.gov/orgs/green-communities-division.

[19] City of Boston, *Building Emissions Reduction and Disclosure*, Oct. 7, 2025, https://www.boston.gov/departments/environment/berdo.

[20] City of Cambridge, *Building Energy Use Disclosure Ordinance*, 2025, https://www.cambridgema.gov/Departments/OfficeOfSustainability/BuildingEnergyUseDisclosureOrdinance.

3. Competition from non-gas technologies

In 2025, Impulse Labs released an induction cooktop with five times the power output of a gas cooktop that can automatically control pan temperature to within a degree. This technological leap fundamentally disrupts the customer experience of cooking.

In the wake of the COVID-19 pandemic and the shift to more time at home, consumers began to invest in home improvements that enhanced comfort and improved air quality. Comprehensive retrofits can integrate electric heating with other improvements, such as ventilation. The mini-split provides efficient zonal cooling, heating, and dehumidification eliminating the annual swap-in and out of a window air conditioner. The performance of combo-washer heat pump dryers has also improved to the point where they are a competitive and efficient space saver that avoids the additional plumbing expense of a gas pipe**.** At a minimum, these retrofits can cut a significant fraction of gas demand for a household, while comprehensive retrofits could eliminate a home's gas usage altogether.

These technologies do not need to be more affordable on an install or operating basis to be disruptive or competitive. Historically, gas on a per energy unit basis was often more expensive than coal, oil, and wood-based heating. Still, it provided its customers with a different set of value propositions that enabled its growth. Affordability is not the sole consideration for customers, as new technology and additional spending can deliver improvements to quality of life.[21]

In all technological classes, there is room for incremental improvements in both performance and customer value. This opportunity may exist with gas equipment, but the pathways

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[21] Early gas service to residential customers required marketing of non-cost features such as cooking and the convenience of supply because it was more expensive in its early days than that of other fuels.

are less clear and fundamentally constrained (e.g. a gas furnace has an upper efficiency limit of 100 percent). For comparison, software improvements in the control of heat pump compressors reduced daily energy use by 19 percent, energy used for backup heat by 38 percent, and the frequency of use of backup heat by 83 percent in a field trial.[22]

Table 2 below lists a sampling of Massachusetts oil delivery companies that offer heat pump installations. These companies generally recognize the threat that building electrification poses to their business model and are actively leveraging their historical customer relationships to offer new products. These companies do not have large, regulated fixed costs and are institutionally more adaptable.

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[22] Elias Pergantis et al., *Field demonstration of predictive heating control for an all-electric house in a cold climate*, APPLIED ENERGY (Apr. 15, 2024), https://www.sciencedirect.com/science/article/abs/pii/S0306261924002034.

Table 2. Sampling of Massachusetts fuel delivery companies that have developed heat pump installation offerings.

Company Name	Location/Service Area	Heat Pump Marketing Text
J.A. Healy & Sons	Nashoba Valley (Acton, Littleton, Westford area)	"ductless heat pumps" and customer mentions "install a couple of mini splits"
FSi Oil and Propane	Western Massachusetts & Northern Connecticut	"ductless mini-split A/C system can offer both heating and cooling throughout the year"
Genove Oil & Air	Boston MetroWest area	"ductless systems and heat pumps"
Bigelow Energy	Greater Boston (Newton, Wellesley, Needham, Brighton, Brookline)	"installation, repair, and service for all cooling systems"
Atlantic-Pratt Energy	Plymouth County (South Shore)	"Heat Pumps" and customer mentions "installing new AC"
Jamie Oil	MetroWest (Ashland, Hopkinton, Framingham, Worcester)	"heating and cooling services"
MacFarlane Energy	Eastern Massachusetts	"heating and cooling services, equipment installations"
Lipton Energy	Pittsfield and Berkshire County	"ductless mini-split system with an electric heat pump to help supplement"
Pioneer Oil & Propane	Worcester County (Worcester, Sturbridge, Auburn, Charlton)	"expertly install mini-splits to suit your home and your needs"
ckSmithSuperior	Worcester and Central MA (Framingham, Marlborough, Leominster)	"mini split ductless air conditioning and more to provide total home comfort"
Propane Plus Heating & Cooling	Southeastern Massachusetts & Rhode Island	"perform reliable work installing and replacing ductless mini-splits"
Columbus Energies	Swansea, MA (serves MA & RI)	Customer testimonial: "had Columbus Energies install mini split heat pumps in our house"

C. <u>Consequences of the Disruptors to the Gas Utility Business Model</u>

The gas system is a fixed cost system. As consumption declines and customers leave the system, the costs become concentrated on declining throughput and a dwindling customer base. Those who remain on the system will be customers who have greater barriers to leaving the system: renters and those with limited access to capital. Under current ratemaking practices, this would result in steadily increasing gas rates. Additionally, as electrification, additional efficiency measures, and non-pipeline fuels become more competitive, the incentives for gas consumption reductions and customer departures increase, effectively creating a price vortex for those customers who remain on the gas distribution system. Figure 4 below illustrates this dynamic.

Figure 4. Illustration of how increasing gas costs concentrate on a declining customer base as the gas system is disrupted. Groundwork Data figure.

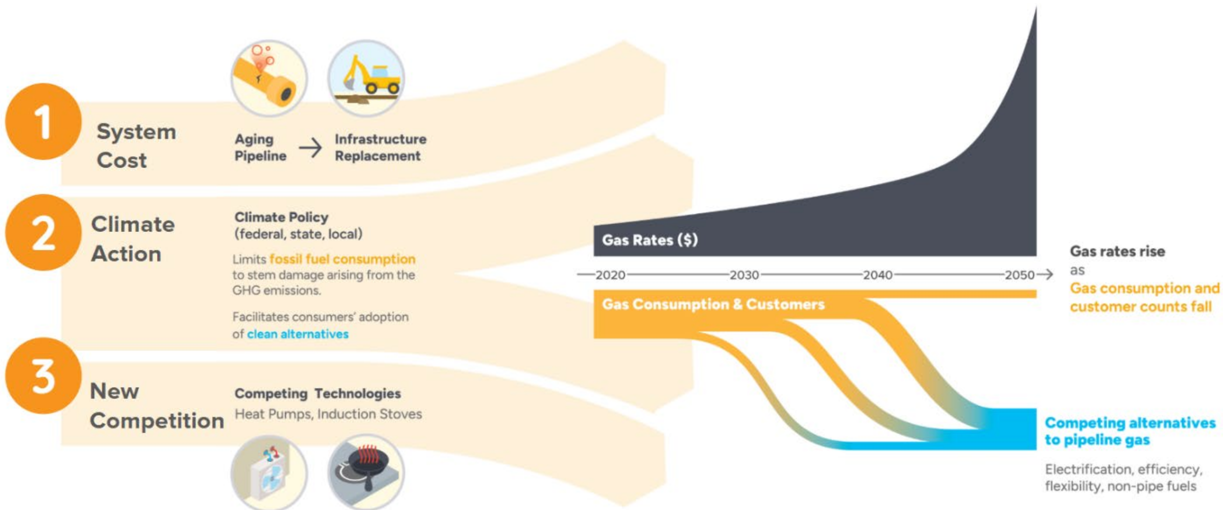

Figure 5 below puts these changes in the context of other energy costs. At some point in the future, it is conceivable that the cost of heating with gas will exceed the cost of heating with an electric-heat pump and delivered fuels. Future electric costs depend heavily on distribution, transmission, and generation policy. In the near term, winter electric heating rates are expected to narrow the gap in cost between gas and electric heating for many customers.[23]

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23 *See* Interagency Rates Working Group, https://www.mass.gov/info-details/interagency-rates-working-group.

The pace at which this transition evolves will depend on several factors, including customer behavior, policy, and how utilities respond to the disruptions. Strong alignment in goals and action will be necessary to avoid customer burdens and stranded assets.

Figure 5. Illustration of how different fuel costs could evolve over time, annotated with major drivers. Climate compliance costs could include carbon pricing or fuel blending policies.

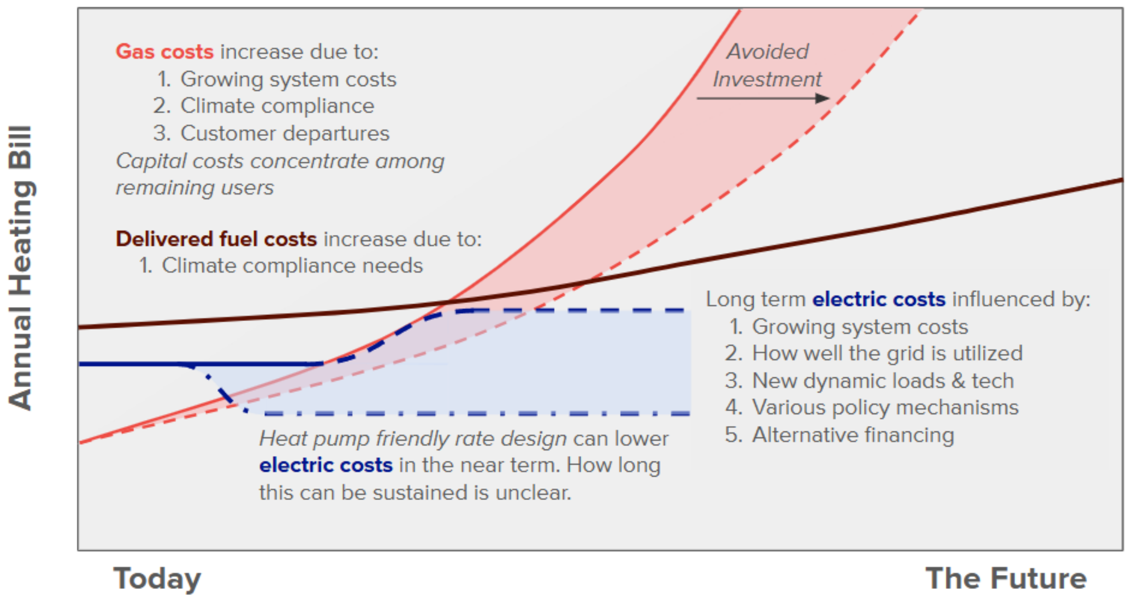
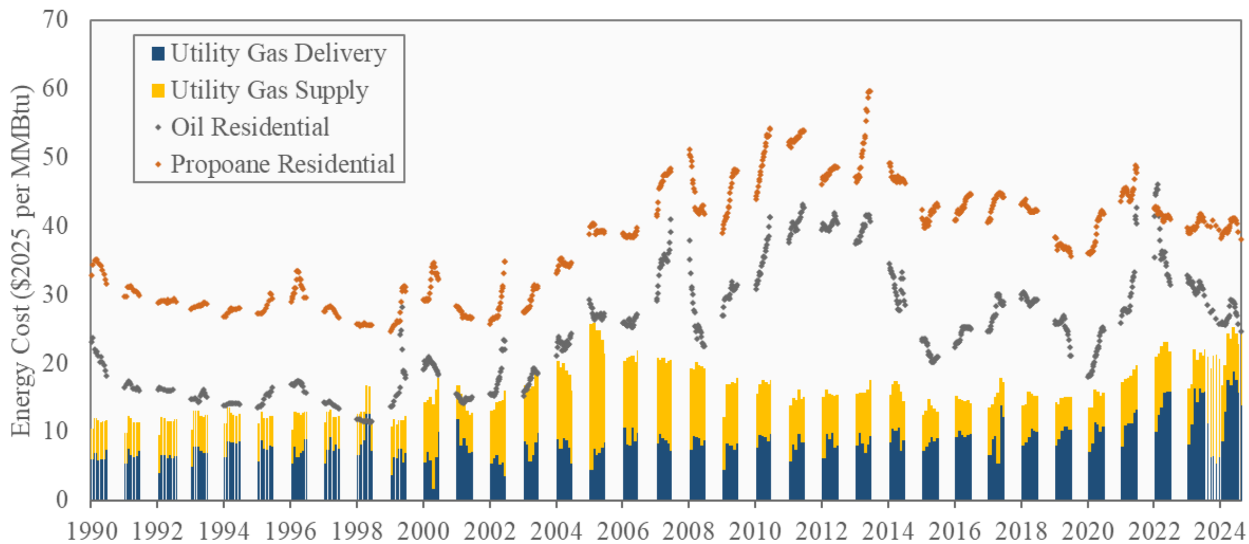


Figure 6 below shows that in recent years, residential utility gas and heating oil prices have converged largely due to increasing fuel delivery costs.

Figure 6. Winter energy prices for gas supply and delivery (yellow and blue bars),[24] delivered residential home heating oil,[25] and delivered residential propane for Massachusetts.



The similar price of oil and gas has limited the favorability of oil-to-gas conversion and challenged the growth of gas. Berkshire, which has the second-lowest gas market share in the Commonwealth (Figure 7 below), noted in their CCP that it "has experienced limited growth in the last several years due in part to the lack of price benefits of natural gas compared with alternative fuels (e.g., fuel oil)."[26] Such limitations on growth, particularly with customers that only require a service connection, have kept system costs concentrated on existing customers. This is also the case right now in Unitil's territory, which has the smallest utility gas market share (Figure 7), and where gas heating costs exceed those of oil on a per MMBtu basis (Figure 8 below).

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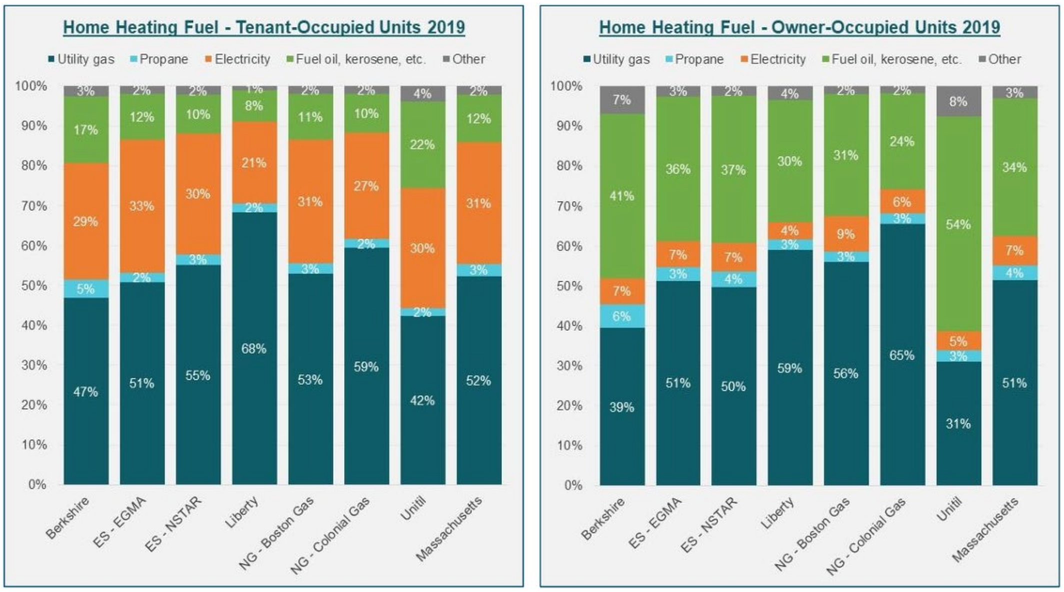
[24] U.S. EIA, *Natural Gas Prices: Massachusetts (selected winter months),* https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMA_a.htm.

[25] U.S. EIA, *Weekly Heating Oil and Propane Prices: Massachusetts* https://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_SMA_w.htm.

[26] *Berkshire*, D.P.U. 25-40, Exh. BCG-CCP, at 16.

In the current 2025 Liberty rate case, Liberty indicated that the average total energy costs are projected to go above $30 per MMBtu for residential heating customers.[27]

Figure 7. Share of home heating fuel by service area. Source: 20-80 Independent Consultant Report and U.S. Census American Community Survey[28]



Utility gas in Massachusetts has not been sufficiently disruptive to move customers away from delivered fuels—failing to deliver on its promise of lower costs—in part because it has failed to capture a significant market share. The argument that lower-cost gas supply enabled by hydraulic fracturing would lead to increased consumer adoption driving lower delivery costs, missed the fact that hydraulic fracturing also lowered the price of heating oil.

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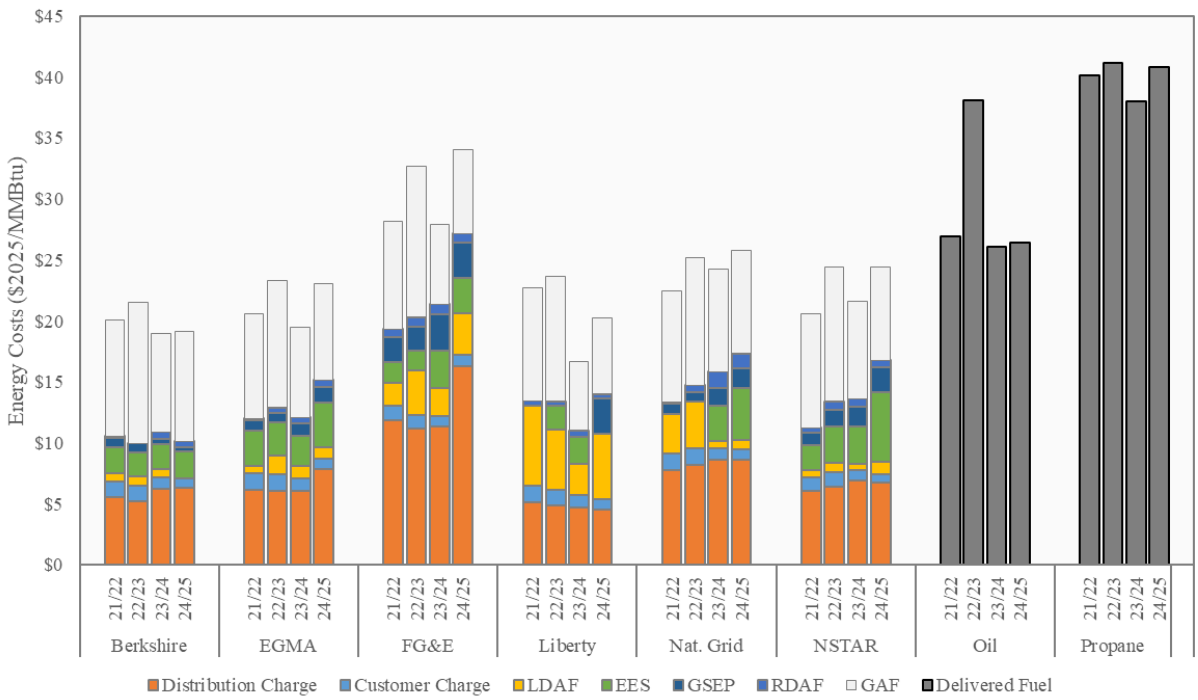
[27] *Liberty*, D.P.U. 25-85, Exh. LU-TRP-16.

[28] Energy and Environmental Economics & Scott Madden Management Consultants, D.P.U. 20-80, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Appendix 3: LDC Characteristics* (Mar. 18, 2022) at 9, extracted from U.S. Census Bureau, *American Community Survey Table B25040*, 2019.

Figure 8. Energy costs broken down by bill component for gas and all-in costs for delivered fuels for December of the indicated heating season.[29] *(LDAF: Local Distribution Adjustment Factor; EES: Energy Efficiency Surcharge; GSEP: Gas System Enhancement Plans; RDAF: Revenue Decoupling Adjustment Factor; GAF: Cost of Gas Adjustment Factor)*



This challenge does not appear to be letting up. Most LDCs show some increase in the overall distribution charge over the past four heating seasons (Figure 8). The two largest contributors to growing rates in recent years have been GSEP and Energy Efficiency surcharges, both levied through the Local Distribution Adjustment Factor ("LDAF"). The GSEP surcharge is an accelerated cost recovery mechanism that is rolled into rates with each rate cycle (FG&E's Distribution Charge jump from 2024 to 2025 shows the outcome of a rate case). Energy efficiency surcharges have increased in recent years due to growing utilization of increasingly comprehensive Mass Save measures, such as electrification incentives. The financing of energy efficiency

[29] Gas rate data obtained from Office of the Attorney General tracking of rates. Where data is available, GSEP and Energy Efficiency (EES) are broken out from the LDAF. Delivered fuels were averaged by season from EIA weekly price data. Prices are in 2025 dollars.

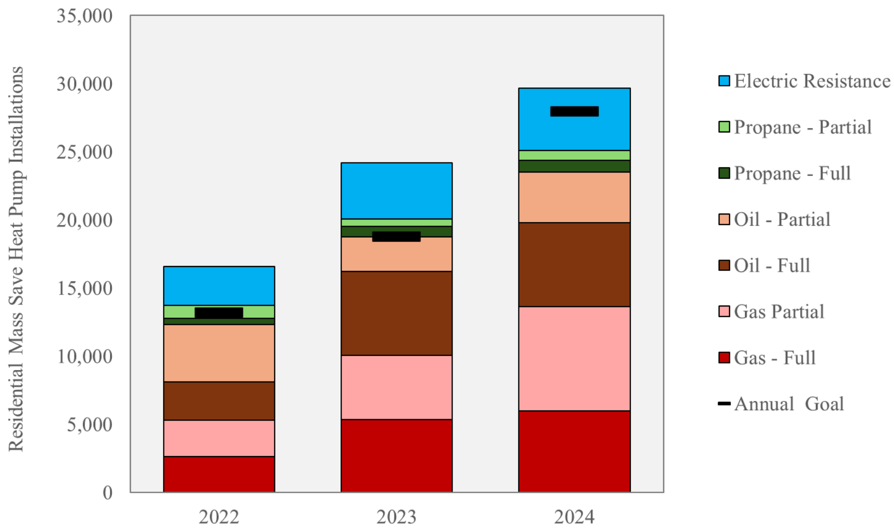
programs is under active evaluation by the Commonwealth.[30] However, one way to consider this cost is that it is equivalent to a cost of \$50-\$100 per ton of CO_2 emitted, reflecting how climate policy acts a driver of gas costs.

D. <u>Evidence of Increasing Customer Adoption of Electric Technologies</u>

The residential sector's voluntary adoption of building electrification measures has been growing rapidly in recent years. During the most recent Mass Save Plan cycle, the pace of heat pump projects nearly doubled from 2022 to 2024, exceeding annual program goals (Figure 9 below). The 2022-2024 cycle also exceeded expectations in two other ways. First, the number of full displacements was more than twice that forecasted; customers preferred complete electrification. Second, the program only achieved these goals due to unexpected demand from gas customers. The initial plan had assumed a lower participation of gas customers (~1,000 full and partial displacements), whereas there was a total of 29,000 full or partial displacements of gas equipment. There were approximately 18,000 fewer oil and propane displacements than expected. Gas customers disproportionately favored electrification projects despite the less favorable operating economics of gas-to-electric conversions at the time.

30 EEA, *Massachusetts Building Decarbonization Clearinghouse Final Report*, 2025, https://www.mass.gov/info-details/ma-building-decarbonization-clearinghouse.

Figure 9. 2022-2024 Mass Save heat pump installations by fuel displacement.[31]



The gas industry recognizes this disruption is underway. For example, in 2021, Scott Madden Management Consultants was serving on the Independent Consultant Team to the local distribution companies in the D.P.U. 20-80 investigation, released a white paper titled: *Facing Disruption Like We Have Never Experienced It Before.*[32] The paper discussed disruptive threats facing utilities such as "the high costs of repairing and replacing aging infrastructure" , "the clean energy transition" , and competing technology options.[33] Scott Madden has also published a blog

31 Mass Save 4th Quarter 2024 Program Administrators' Quarterly KPIs, https://ma-eeac.org/wp-content/uploads/2024-Q4-KPI-EWG-Reporting-3-13-255361632.xlsx.

32 Christin Lyons and Michael Montgomery, *Facing Disruption Like We Have Never Experienced It Before*, Scott Madden Management Consultants, Sept. 2021, https://www.scottmadden.com/content/uploads/2021/09/ScottMadden_Facing_Disruption_Like_We_Have_Never_Experienced_it_Before.pdf

33 *Id*.

posting titled *Planning for Gas Utilities: Managing the Energy Transition* that explores similar themes discussed here. [34]

The National Association of Regulatory Commissioners ("NARUC") has also commissioned a Task Force on Natural Gas Resource Planning that aims to "envision novel process approaches for considering natural gas distribution resource planning in their states," recognizing investment needs, decarbonization, and an evolving technology landscape. [35]

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[34] Ed Baker, et al., *Planning for Gas Utilities: Managing the Energy Transition*, https://www.scottmadden.com/insight/planning-for-gas-utilities-managing-the-energy-transition

[35] NARUC, *Task Force on Natural Gas Resource Planning*, https://www.naruc.org/committees/task-forces-working-groups/task-force-on-natural-gas-resource-planning/gas-task-force/

II. APPENDIX B: Methane Emissions & The Limitations of Pipe Replacement in Achieving Climate Compliance

Summary

- Methane is a short-lived but potent greenhouse gas that causes a significant near-term warming impact. This impact rapidly fades as the gas decays in the atmosphere.
- The dual impact of fugitive methane emissions from utility distribution systems and the combustion of fossil gas delivered by these systems contributes to warming.
- Fugitive methane emissions from the natural gas distribution system account for 1.1 percent of all GHG emissions and 4.4 percent of gas system emissions (both Scope 1-leaks and Scope 3-combustion).
- Methane's powerful but short-lived warming effect means that reducing its emissions can deliver rapid climate benefits; however, long-term climate goals require addressing both methane and persistent greenhouse gases like CO_2 to limit warming.

Policy Relevance

Prioritizing the replacement of leak-prone pipes in utility distribution systems can provide some benefits for mitigating methane emissions, but these benefits are ultimately limited when considering broader climate goals. While fixing leaks helps reduce fugitive methane emissions, the high cost of such infrastructure investments must be weighed against their long-term impact, especially if the underlying gas systems continue to operate indefinitely. There is an escalating risk that these investments may become stranded assets as energy policy and market trends shift toward alternative heating solutions, meaning that costly upgrades could lose their value and relevance in a future where fossil gas use is dramatically reduced or eliminated. The value of pipe replacement as a mitigation strategy should be viewed in the context of its cost relative to the emissions reductions that it delivers.

A. Methane Gas is a Short-Lived, but Potent Greenhouse Gas

Methane gas ("CH_4") is a short-lived but potent GHG: per molecule, it has a greater warming effect than CO_2, but this effect fades relatively rapidly. On average, an emitted molecule of methane contributes to intense warming for about a decade before atmospheric chemical processes oxidize it, converting it into CO_2 and water vapor, which are less intense GHGs on a per-molecule basis. This fading characteristic distinguishes methane from CO_2, which, once emitted, mostly persists in the atmosphere for centuries.[36] Both their relative potency and lifetimes are now well understood, although, the underlying science and ongoing refinement of quantitative measures to compare them continue to improve.

Methane emissions have dramatically increased in the industrial age. During this era, methane's contribution to warming has been about half that of CO_2.[37] Methane can be generated via several natural processes, including biological methanogenesis in wetlands, natural venting of subsurface methane, and incomplete combustion of biomass in wildfires. These processes are relatively small compared to recent anthropogenic contributions, which include breakdown of waste and wastewater, biomass burning, plant and animal agriculture, and fugitive emissions of fossil methane from the extraction of fossil fuels and the pipeline gas supply chain.[38]

A ton of methane traps approximately 114 times more heat than a ton of CO_2, but because of the different lifetimes of the gases, a more nuanced metric is required. A commonly used method to measure a GHG's relative potency is Global Warming Potential ("GWP"), which quantifies the amount of warming caused by the GHG over a specified time relative to CO_2.[39]

Here is a way to understand GWP. Assume the emissions of one metric ton ("ton") of methane today. That ton of methane will start having a powerful effect on the climate immediately, but after about 10 years, most of it will be converted to CO_2. GWP tells us the equivalent amount

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[36] Sophie Szopa, et al., *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, at 6.6, CAMBRIDGE UNIVERSITY PRESS, at 817–922 (2021), https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-6/#6.6.

[37] *Id*. at 6.4.2.

[38] *Id*. at 6.2.1.

[39] Other methods have been developed including the Global Temperature change potential (GTP) and GWP, which seek to capture different dynamics in how GHGs contribute to warming.

of CO_2 we'd have to emit today to have the same warming effect over some specified time horizon as that initial ton of methane. Over a short time horizon, like 20 years (also denoted as GWP-20), the initial warming spike from methane is substantial, as the gas is present for roughly half the time before it degrades. Thus, a large amount of CO_2 would be required to match the methane's effect on the climate. Over a longer timescale, such as 100 years (also denoted as GWP-100), the initial warming spike from methane would be more modest compared to the persistent effect of CO_2 (i.e., CO_2 has 90 years after the methane degrades to "catch up" in its cumulative impact).

The most recent IPCC report (AR6) calculates the GWP-20 and GWP-100 of methane to be 82.4 and 29.8, respectively. This means that more than 80 tons of CO_2 would be required to match the warming effect of one ton of methane over the first 20 years after it is emitted, but only approximately 30 tons of CO_2 would be necessary to match that warming effect of the methane over the 100 years after it is emitted. These figures have been revised over time as climate science has improved, as shown in Table 3 below.

By convention, CO_2's GWP over all timescales is 1; CO_2 is the point of reference for comparing the impact of other gases. The term "CO_2-equivalence" or "CO_2e" reflects the application of a GWP to a non-CO_2 GHG (CO_2e = non-CO_2 GHG emissions × GWP).

Table 3. Global Warming Potentials for Methane

IPCC Reports	100-year (GWP-100)	20-year (GWP20)
2007 Fourth Assessment Report (AR4)	25	72
2014 Fifth Assessment Report (AR5)	28	84
2021 Sixth Assessment Report (AR6)	29.8	82.4

The selection of a weighting method for policy decision-making reflects a value judgment. Practically speaking, achieving the net-zero emissions target will involve the use of the GWP to compare different GHGs and make decisions about which GHGs to prioritize. If a 20-year time horizon (GWP-20) is used for methane, that would indicate a preference for prioritizing methane reductions to avoid near-term warming. On the other hand, if a 100-year time horizon (GWP-100) is used, that would shift the priority toward mitigating CO_2 emissions to limit warming in the longer run.

Using a shorter time horizon (e.g., GWP-20) implies a high societal discount rate, while using a longer time horizon (e.g., GWP-100) implies a lower societal discount rate, capturing a fuller temporal scope of climate impacts. There may be good reasons to prioritize mitigating near-term warming impacts due to non-linearities or "tipping points" associated with climate change, but avoiding such risks would further require broad emissions reductions across all sectors.

Alternatively, measures that prioritize CO_2 mitigation also, incidentally, prioritize limiting ocean acidification. While often overlooked, mitigation of ocean acidification is directly tied to the goals of net-zero and has been a component of the developing global carbon mitigation goals. As atmospheric CO_2 levels rise, so does the uptake of CO_2 by the ocean. As it dissolves in the ocean, it increases the ocean's acidity. Between 1950 and 2050 ocean pH (a measure of acidity with lower values being more acidic) has dropped from 8.15 to 8.05. The impacts of this and further acidification are complex, but a notable example is that it slows and constrains the growth of coral reefs, shellfish, and base organisms of food webs. These impacts are expected to have a negative impact on fisheries.

These complexities are highlighted because methane as a greenhouse gas is poorly understood. Prioritization of methane mitigation is important, but that prioritization of methane necessitates certainty in mitigation efforts.

B. Sources of Methane from the Gas System

Methane is emitted from nearly all components of the gas system, including mains, services, regulators, compressors, meters, building gas lines, appliances, and end-use equipment that is both in use and quiescent. Methane emissions from LDC-owned assets (pipes, services, meters, regulators, etc.) are "Scope 1" emissions. There are also significant upstream emissions from natural gas wells and extraction equipment, as well as dormant wells, processing, and transmission systems. These can be significant and contribute to the life-cycle emissions impact of fossil fuels, but are not included in the DEP GHG inventory, nor are they considered Scope 1 emissions.[40]

Alongside regular leaks, methane emissions also occur from routine maintenance, such as blowing of gas from pipelines, and dig-in mishaps caused by damage from third parties. Older equipment is more likely to emit methane at greater volumes because the distribution pipe (mains and services) degrades over time. The rate of degradation, and the volume of methane released

[40] This would be typically considered upstream gas production emissions that are classified as "Scope 3" alongside downstream consumption of gas.

from it, depends on several factors, including: pipe material (older cast iron and bare steel pipes have higher leak rates than modern plastic); pipe manufacturing methods; pipe age and installation date; soil conditions (such as corrosivity, exposure to extreme temperatures, moisture content, and ground movement); operating pressure within the system, temperature fluctuations that cause thermal expansion and contraction; the quality of pipe joints and fittings, maintenance history and inspection frequency; external factors like construction activity or root intrusion; and the specific design and manufacturing standards under which the infrastructure was originally installed.

C. <u>How the State Measures Methane Emissions from the Natural Gas System</u>

Chapter 21N directs the Department of Environmental Protection ("DEP") to measure the relative impact of GHGs "based on the best available science, including from the Intergovernmental Panel on Climate Change."[41] In its statewide GHG accounting, the DEP largely follows the methodology of the EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks Greenhouse Gas Reporting Program. Until January 2025, this has used the AR4 GWP-100 value of methane (25); however, this has been updated to the AR5 GWP value (28) but has yet to be incorporated into the state inventory.[42] The general practice of parties to the IPCC and the Paris Climate Accords informs the EPA's approach.

The IPCC acknowledges that there may be policy-appropriate reasons to use other metrics and even separate gases into multiple baskets for policy purposes without attempting to compare

[41] G.L. c. 21N, § 1.

[42] 40 C.F.R. Part 98, Table A-1.

emissions factors.[43] This observation is relevant to situations where methane and CO_2 mitigation strategies intersect or even conflict. For example, the mitigation of methane emissions is invoked in GSEP and several of the LDC's CCPs as a justification for replacing leak-prone gas infrastructure. However, the continued consumption of gas at current scales from such infrastructure, and associated CO_2 emissions, is not aligned with the Commonwealth's emission limits. If reductions in gas consumption were to occur, the benefits of replacing leak-prone pipes may be limited, or such replacement may be imprudent.

310 CMR 7.73: Reducing Methane Emissions from Natural Gas Distribution Mains and Services, effective in March 2021, imposes binding, annually declining emission limits measured in metric tons of CO_2e on major gas utilities, supported by detailed reporting requirements. The regulation's scope covers all active distribution mains and services owned, leased, operated, or controlled by the LDCs.

The utilities annually report miles of main and services by material type and vintage and use a MassDEP-provided calculator to calculate emissions. The calculator uses standard emissions factors for mains and services that are consistent with the MassDEP GHG inventory.

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[43] Piers Foster, et al., *The Earth's Energy Budget, Climate Feedbacks and Climate Sensitivity; Physical Considerations in Emission Metric Choice*, at 1017 (2021), https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-7/ ("This report does not recommend an emissions metric because the appropriateness of the choice depends on the purposes for which gases or forcing agents are being compared. Emissions metrics can facilitate the comparison of effects of emissions in support of policy goals. They do not define policy goals or targets but can support the evaluation and implementation of choices within multi-component policies (e.g., they can help prioritize which emissions to abate). The choice of metric will depend on which aspects of climate change are most important to a particular application or stakeholder and over which time horizons. Different international and national climate policy goals may lead to different conclusions about what is the most suitable emissions metric.").

Calculating emissions from the combustion of fossil fuels is straightforward due to well-established emissions factors (CO_2 emissions per unit of energy are predictable and consistent)[44] and reasonably accurate fuel consumption data (e.g., sales, metering, etc.). Measurement and tracking of methane emissions is fundamentally more complex across all sectors due to intrinsic variability in emission sources and limitations in measurement capabilities. Leak prevalence and extent vary significantly across the gas system. As parts of the system change—due to pressure fluctuations throughout the year or degradation over time—the amount of leaked gas from a specific component can vary. Predicting and estimating this escape is far less certain than the well-understood release of CO_2 from the combustion of gas and the precise metering of gas sales.

Lost and unaccounted for ("LAUF") natural gas has been proposed at times as a proxy measurement for leak emissions. LAUF is the gas lost between the purchase from the "city gate" meter and the customer meter. This difference in gas sold and gas bought is often referenced as a possible value to quantify fugitive methane. However, LAUF gas could be due to several factors, including system leaks, pipeline damage, theft, measurement errors, and consumption at inactive meters. Discerning the scale of each of these impacts would require substantial monitoring.

The DEP GHG inventory[45] calculates gas system emissions from miles of mains,[46] the

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44 See EPA, *Emissions Factors Hub*, https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf.

45 Massachusetts Department of Environmental Protection (MassDEP), *Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2021, with Partial 2022 & 2023 Data, Boston, MA*, 2024, https://www.mass.gov/lists/massdep-emissions-inventories.

46 U.S. Department of Transportation, *LDC Reports to PHSMA*; *PHMSA, Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

number of services,[47] gas company meter and regulator stations, customer meters,[48] post-meter leaks,[49] and mishaps.[50] These activities are then multiplied by an activity factor and the GWP-100 for methane to estimate the contribution of these sources to the Natural Gas Systems sector in DEP's GHG inventory.

Natural gas systems are responsible for nearly half of methane emissions in the Commonwealth, as tracked by DEP's GHG inventory (47.8 percent).[51] In 2022, the most recent year with complete data, inventory methane emissions from the natural gas distribution system totaled 0.74 $MMTCO_2e$ based on GWP-100.[52] This is 1.07 percent of all GHG emissions, and 4.42 percent of gas system emissions (Scope 1 leaks + Scope 3 combustion) in 2022. This is illustrated by Figure 10 below.

By 2030, Natural Gas Distribution and Service emissions are limited to 0.4 $MMTCO_2e$; by 2050, emissions are limited to 0.5 $MMTCO_2e$. The reason for the limit increase is a 2022

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47 *Id.*

48 LDC Reporting to EIA (Form 176).

49 *Id.*

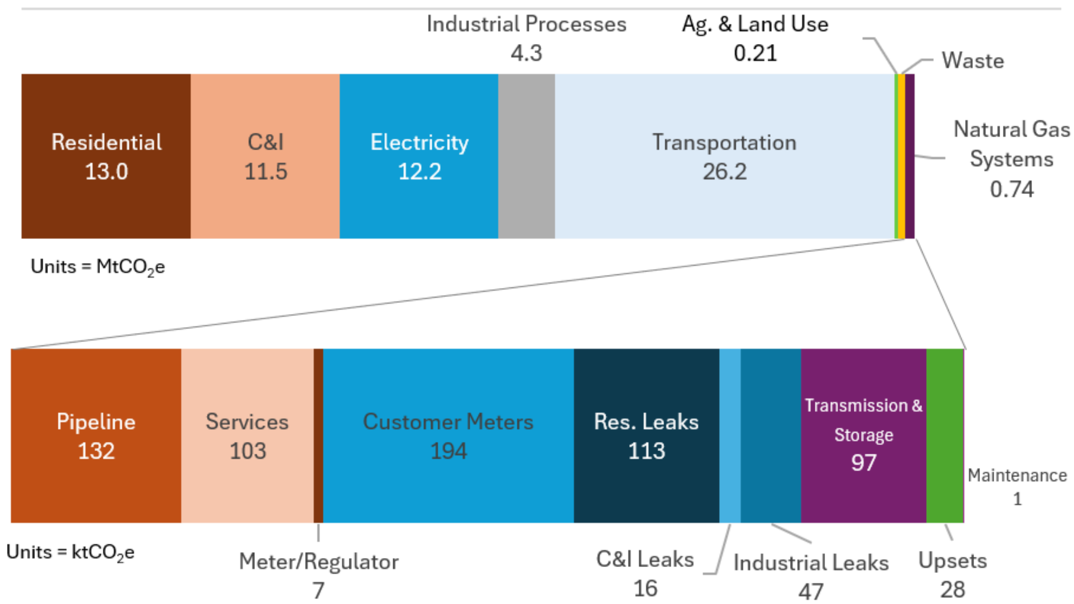
50 Standard per-mile incident rates.

51 MassDEP, *Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2021, with Partial 2022 & 2023 Data, Boston, MA* (2024), https://www.mass.gov/lists/massdep-emissions-inventories. Other sources include: wastewater (20.7 percent); solid waste landfills (10.6 percent); incomplete combustion of fossil fuels and municipal solid waste across heating, transportation and power generation (14.3 percent); and, agriculture (6.6 percent).

52 MassDEP, *Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2021, with Partial 2022 & 2023 Data, Boston, MA* (2024), https://www.mass.gov/lists/massdep-emissions-inventories.

methodology change between the calculation of the 2025/2030 and 2050 sublimits, which now includes post-meter leaks in the GHG inventory.[53]

Figure 10. Breakdown of 2022 Statewide GHG emissions (top) with a breakout of emissions from natural gas systems (bottom).



D. Pipeline Replacement Scenario Analysis

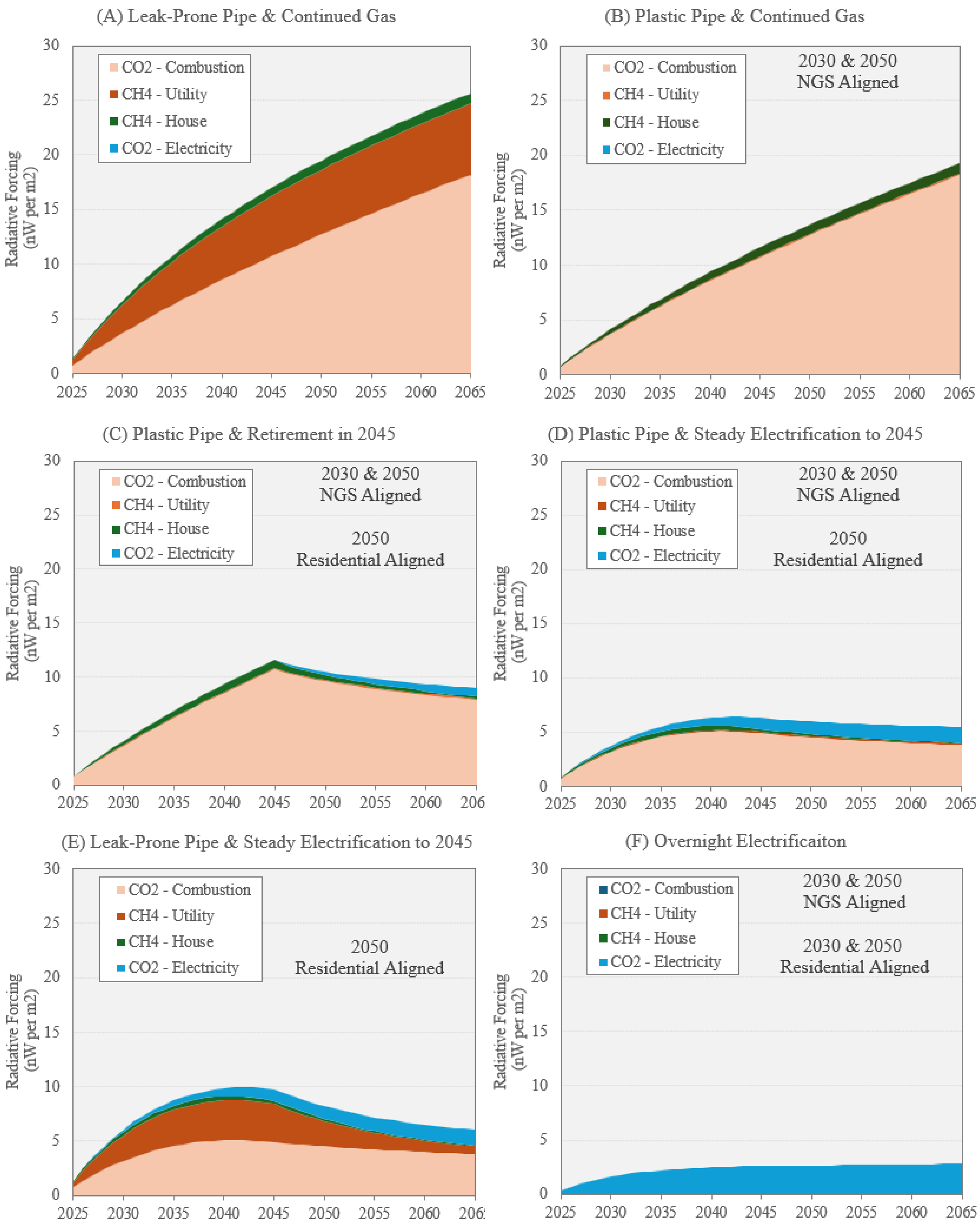
Figure 11 presents a synthesis of the tradeoffs associated with targeted electrification. The figure shows the radiative forcing (a measurement related to temperature impact) from the emissions originating from the neighborhood of homes. My use of this metric aims to more accurately convey how the climate is impacted over a multi-year period of emissions than the current accounting approaches.[54] The figure indicates whether the reductions in emissions generally align with the 2030 and 2050 Natural Gas Systems ("NGS") and Residential sector

53 *2050 CECP*, at 79, fn. 111.

54 Such accounting approaches are suitable for economy-wide regulation, however, developing specific policy often requires having a more granular understanding of the behavior of different GHGs.

sublimits, based on a conventional accounting of GHG emissions. An overview of the assumptions is provided below.

Figure 11. Absolute warming impact from a cohort of 100 homes under several pipe material and electrification scenarios.



Scenario A assumes the homes continue to use gas in a business-as-usual fashion, delivered through a cast iron pipe using existing emissions factors. Here, both ongoing methane leaks and combustion lead to a steadily increasing warming impact. Replacing the pipe (Scenario B) eliminates methane emissions; however, continued combustion remains incompatible with net-zero goals. Retiring the system and electrifying all at once in 2046 (Scenario C) levels off emissions but does not achieve near-term reduction goals. Steadily electrifying (5 homes per year—a pace aligned with end-of-life replacements) reduces the accumulation of combustion emissions (Scenario D). This scenario does not align with the 2030 limit, which reflects the failure to scale up electrification efforts over the past several years. A leak-prone pipe-served cohort that gradually electrifies and retires the gas system by 2045 (Scenario E) has a similar warming impact at the end of the time horizon but experiences a larger overall impact due to the near-term warming from fugitive methane leaks. Electrifying all homes in 2026 (Scenario F) has the smallest warming impact.

These scenarios demonstrate the severe limitation of pipe replacement alone. Pipe replacement can limit emissions, but the continued consumption of pipeline gas precludes sufficient emissions reductions (A → B). Replacing leak-prone pipes and retiring the system at a future date (~2046) can align with the 2050 limit but still has a high warming impact (A → C). It depends on the pace of electrification. Immediate electrification (A → F) is the scenario most closely aligned with the Commonwealth's emissions limits but requires a notable shift in efforts. Earlier electrification reduces the accumulation of CO_2 in the atmosphere, and if done fully by 2050, it aligns with net zero aims. However, a steady (end-of-life replacement) pace of electrification is not sufficient to align with 2030 limits at this point.

The comparison of the steady electrification, scenarios (D and E), illustrates the tension and limited impact associated with pipe replacement. The pulse of methane from the leak-prone pipe system that would be retired in 2045 is a significant near-term contributor to warming, but it fades over time. In 2050, it contributes 23 percent of the warming impact. If the system is eventually retired, the emissions mitigation benefit of any pipeline replacement is small in the long run.

These savings come at a high cost. The 20-year social damage of the leaked methane would be approximately $156,000 based on EPA estimates for the social cost of methane emissions. This is far below the $2 to $10 million cost of pipe replacement observed across the LDCs. Pipe replacement is simply a very expensive mitigation strategy. Assumptions underlying the pipe-replacement scenario analysis shown above in Figure 11:

1. 100 gas-served single-family homes on 1 mile of gas service
2. Annual heating demand 80 MMBtu per home gas with electrification leading to a 300 percent average efficiency gain from electrification (7.81 MWh / home)
3. Emissions Factors[55]
   - Cast Iron Main: 1,157.3 kg CH_4 / mile
   - Plastic Main: 28.8 kg CH_4 / mile
   - Leak Prone Service : 14.5 kg CH_4 / service
   - Plastic Service : 0.3 kg CH_4 / service
   - Meter: 1.49 kg CH_4 / meter
   - Home: 2.3 kg CH_4 / house
   - Gas combustion: 0.53 tCO_2 / MMBtu
   - Electric: Cambium[56] High Renewable Energy Costs with Low Natural Gas Prices Scenario (Month 12, hour 17) ISO New England. "Worst winter hour, worst case scenario". Table below is kg CO2 / MWh

2025	2030	2035	2040	2045	2050
281.4	204.9	99.6	84.9	57.7	41.4

55 MassDEP Inventory.

56 Pieter Gagnon, et al., *Cambium 2024 Scenario Descriptions and Documentation*, National Renewable Energy Laboratory, https://www.nrel.gov/docs/fy25osti/93005.pdf.

4. Warming factors[57]:
   - CO_2: 1.76E-18 W m^{-2} g^{-1}
   - CH_4: 2.00E-16 W m^{-2} g^{-1}
5. GHG Decay[58] (This representation is based on an early, simplified atmospheric model that has since been enhanced with more advanced methods):
   - CO_2: Response function derived from Bern Carbon Cycle Model[59]
   - CH_4: exponential decay with half-life of 12 years.

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57 Gunnar Myhre, et. al., *Anthropogenic and Natural Radiative Forcing Supplementary Material; In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, 2018, https://www.ipcc.ch/site/assets/uploads/2018/07/WGI_AR5.Chap_.8_SM.pdf.

58 Piers Foster, et. al., *Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, 2007, https://www.ipcc.ch/site/assets/uploads/2018/02/ar4-wg1-chapter2-1.pdf.

59 *Id*., at 213, Table 2.14 Footnote A.

III. APPENDIX C: Technical and Policy Review of Low Carbon Fuels

Summary

- Low carbon fuels ("LCFs") support net zero targets when used in roles that provide distinctive energy services.
- Several Massachusetts and national-scale studies have demonstrated that Renewable Natural Gas ("RNG") and hydrogen are inferior decarbonization strategies.
- The design of state and local policy has reflected this understanding, as well as the challenges associated with incorporating LCFs into emissions reductions.
- LDC and industry claims overstate and misconstrue the benefits associated with RNG.
- Hydrogen faces distinctive challenges as a pipeline fuel in existing or new dedicated networks.

Policy Relevance

Renewable natural gas and hydrogen are shown to be inferior decarbonization strategies due to their relatively high production costs and sub-optimal use of energy and material inputs, which could be better directed to other sectors. While pipeline gas consumption needs to decline precipitously to achieve emissions limit goals, it remains preferable to use fossil gas for residual pipeline gas use rather than substitute with RNG or blend in hydrogen. Residual use is allowed up to a point under the Commonwealth's net zero framework that allows gross emissions up to 15 percent of 1990 levels. Moreover, the current RNG market is rife with policy distortions. A lucrative subsidy regime over-incentivizes RNG for use predominantly in the transportation sector. Part of this is a result of a policy decision in California to credit methane avoidance in some RNG production pathways—a decision that is now, in fact, being phased out. This subsidy regime has led to gas utilities mischaracterizing the benefits of RNG to promote its use relative to other strategies.

A. LCFs are an Inferior Decarbonization Strategy in the Heating Sector

The Massachusetts 2050 Decarbonization Roadmap's Energy Pathways to Deep Decarbonization report ("Roadmap Pathways Report") conducted a pathways analysis that specifically explored the question of whether LCFs would be suitable for the buildings sector.[60]

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60 Ryan Jones et al., *Massachusetts 2050 Decarbonization Roadmap: Energy Pathways to Deep Decarbonization*, at 35–37 (2020), https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download ("Roadmap Pathways Report").

The analysis simulated an energy market with fixed prices of $20 per MMBtu for hydrogen, $30 per MMBtu for RNG, and $40 per MMBtu for liquid fuels. The analysis conducted a cost-minimization modeling exercise comparing two scenarios, one with a high level of building electrification (All Options) and one with half as much (Pipeline Gas) that both achieved a gross economy-wide emission reduction of 90 percent.[61]

Figure 12 below summarizes the high-level results. The *All Options* scenario exhibits a lower utilization of "Net Zero Carbon Imports," the study's term for LCFs, due to the high level of electrification in this scenario, resulting in a lower overall fuel demand to achieve the emissions reduction target. The bulk of LCFs was allocated to the transportation sector, which still relies on some fossil fuels, "Petroleum Imports." The *Pipeline Gas* scenario maintains a reliance on utility gas for building heat, accounting for about half of the final heat demand in 2050.[62] Since there was less electrification in this scenario, more fuel would be required across the entire energy system. To achieve the required emissions reductions at the lowest cost, the model allocated LCFs to displace residual fossil fuel demand in the transportation and industrial sectors *first*. While liquid LCFs cost more than the fossil fuels they displace, this cost premium is lower than that of RNG when substituting for fossil gas. LCFs only displaced a fraction of the scenario's residual pipeline gas demand. Because the model still allowed some gross emissions, the residual pipeline gas demand for buildings was still allowed and economically preferred over RNG to achieve the emissions limit.

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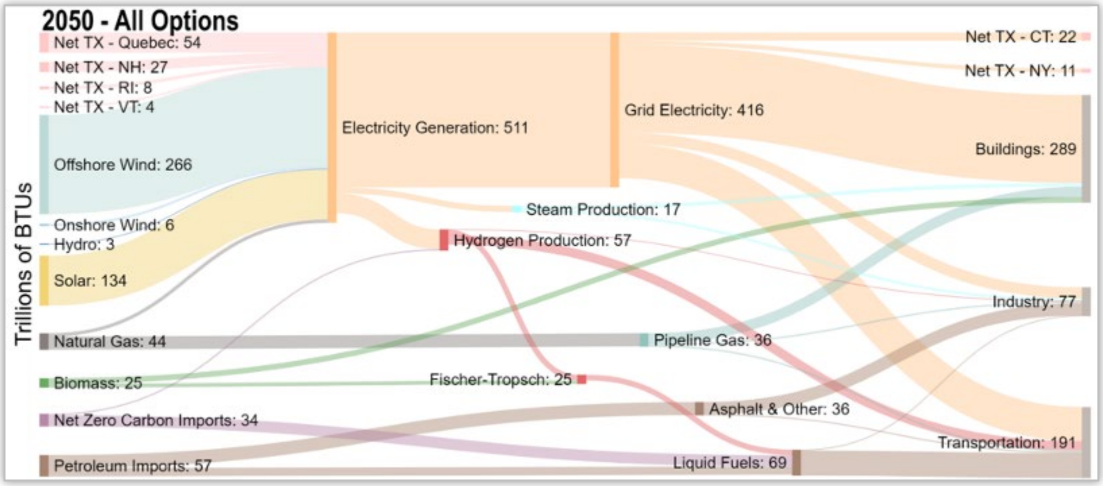
[61] The Roadmap Pathways Report modeling was more stringent than the 2021 Climate Law's requirement of an 85 percent reduction.

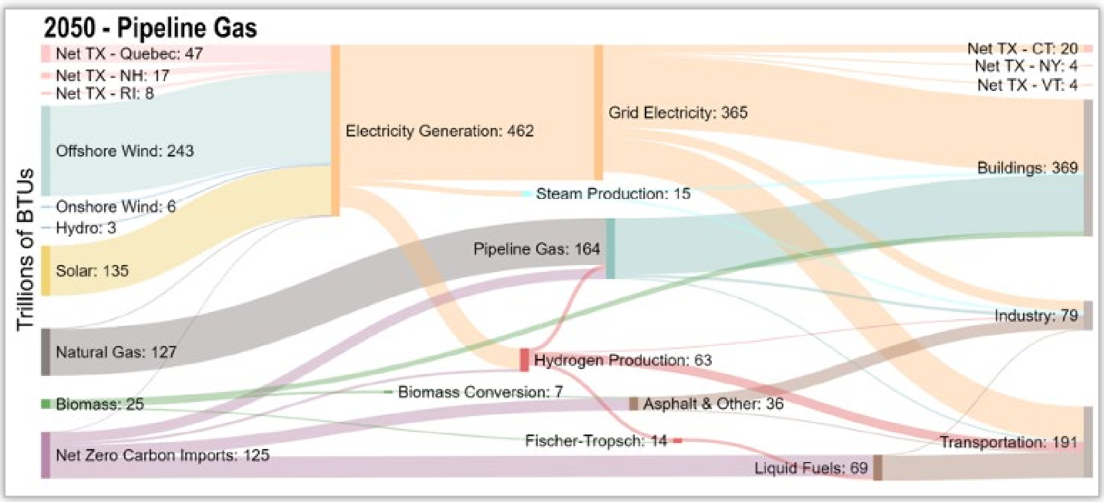
[62] Both scenarios included a 30 percent reduction in final building heating energy demand.

The Roadmap Pathways Report's analysis provides the following synopsis of its findings on hydrogen: "The source of hydrogen was primarily in-state electrolysis, with differing amounts of hydrogen imports depending on the pathway. Most of the hydrogen produced was used to meet final energy demand in the transportation sector. Secondary uses of hydrogen included synthesizing liquid hydrocarbon fuels with carbon captured in Massachusetts, and to a very limited extent, direct combustion in thermal power plants."[63] Compared to RNG, The Roadmap's analysis of hydrogen was more illustrative (i.e., how it could play a role) rather than analytical (what, if any, role it could play). Specific challenges associated with hydrogen substituting for natural gas are discussed in section E.

63 Roadmap Pathways Report, at 66.

Figure 102. Sankey diagrams for 2050 energy use in the All Options (electrification reference) and Pipeline Gas (approximately half as much electrification) scenarios.





B. <u>The RNG Market is Distorted by Inconsistent Incentives</u>

A range of federal and state subsidy programs has primarily influenced recent growth in various LCFs. This section examines the implications of the two most influential fuel standard policies. Additionally, it should be noted that new LCF tax credit initiatives are evolving at both the federal[64] and state[65] levels.

The Federal Renewable Fuel Standard ("RFS") and the California Low Carbon Fuel Standard ("LCFS") were developed in 2005 and 2007, respectively, and were explicitly designed to increase adoption of LCFs at a time when the outlook for electric vehicle ("EVs") was not as positive or dominant as it is today.[66] RNG for vehicle use[67] is an established pathway under both polices. Because these attributes are largely indexed to the price of liquid fuels, they create a significant subsidy for RNG relative to the cost of fossil methane, which heavily incentivizes RNG pathways. When RNG earns credits valued against expensive liquid fuel compliance costs, it only needs to be competitive with conventional natural gas.

The size of these subsidies is astonishing. Using CARB carbon intensity values provided by National Grid in the information response Exh. AG-1-9, we observe that CARB scores certain RNG (or Bio-LNG) pathways at substantial negative values—which is discussed in the next section. At current LCFS credit prices, this garnishes a subsidy of $25 per MMBtu; at 2020 LCFS

64 The Inflation Reduction Act instituted a series of incentives for LCFs that have been partially rolled back directly by the Trump administration or through the One Big Beautiful Bill Act ("OBBBA"). Notably, the OBBBA revised the 45Z tax credit for transportation LCFs, which could include RNG for vehicle use. The revisions included extending the credit for an additional two years (through 2031) and adjusting life cycle emissions accounting practices.

65 Sustainable Aviation Fuel Tax credits have been implemented in Minnesota, Nebraska, Illinois, and Washington.

66 The RFS never integrated an EV compliance pathway, while the LCFS has shifted over time to align with broader electric vehicle goals.

67 Largely as compressed natural gas or "CNG" in trucks.

prices,[68] this was $84 per MMBtu. The commodity prices of natural gas are below $5, and these producers can receive additional subsidies from the federal renewable fuel standard.

A regrettable, and unintended, accident of this complex market design is that it places a thumb on the scale of RNG relative to electric uses of biogas or other advanced fuels. Take, for example, National Grid's CCP's "RNG 'State of Play' in US,"[69] where it cites an American Biogas Council ("ABC") inventory of 338 RNG facilities in the U.S. and Canada. This number overlooks ABC's inventory of over 2,200 biogas-producing sites in the U.S., with the balance being biogas facilities that produce heat and/or power through direct burning (rather than purification) of biogas. Most of these direct-burn facilities are older and were built before the emergence of the modern RNG attribute market. Some of the RNG facilities represent new digestors as well as some conversions of direct-burn facilities.

In 2023, the EPA explored developing an electric compliance pathway for the RFS that would allow for the generation of RFS attributes[70] from the direct burn of biogas rather than the upgrading to RNG.[71] Because of this potential change, WM (formerly Waste Management) announced at the time that it would maintain two landfill electricity generation sites rather than convert it to RNG as planned.[72] At the time, the RNG Coalition, American Biogas Council, and

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68 LCFS credit prices are available here: https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard. Current prices used in this calculation are approximately $60 per tCO_2. 2020 prices were approximately $200.

69 *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 70.

70 Also known as a Renewable Identification Number ("RIN").

71 Currently, an RNG producer can earn LCFS and RFS credits anywhere in the US, where as a biogas electricity producer can only earn LCFS credits, and only if connected to CAISO.

72 Cole Rosengren, *How the EPA's Renewable Fuel Standard Program Changes Could Be a Boon for Landfill and AD Operators*, WASTE DIVE (Feb. 16, 2023), https://www.wastedive.com/news/epa-rfs-rin-biogas-rng-ev-wm-republic-anaergia/641997/.

RNG producers were supportive of including an electric pathway.[73] The proposal did not proceed despite this support, but it would have created a more level playing field among pathways and likely would have slowed the growth in pipeline-quality RNG facilities.

C. RNG is Not "Carbon-Negative"

The characterization of RNG as "carbon-negative" is incorrect and misleading, as it reflects an erroneous understanding of life cycle analysis ("LCA") that is unfortunately prevalent in industry and through its use in existing policies, such as the LCFS.

Life cycle assessment ("LCA") is a decision-support tool that has functional limitations in policy-making. LCA is primarily used for assessing the impacts of a particular product under a fixed set of assumptions: it provides a helpful snapshot for understanding the impact of certain choices under specific conditions. LCA, however, is fundamentally challenged as a policy tool due to its limits in capturing and assigning changes that may occur across geographies, time, and markets. Due to these limitations and uncertainties, the use of LCA in policy requires substantial administrative burdens for both regulators and regulated parties.

Under the Low Carbon Fuel Standard ("LCFS"), fuels that have a lower carbon intensity compared to the benchmark fossil fuel receive greater credits. These carbon intensity values are calculated using modifications to the federal Greenhouse gases, Regulated Emissions, and Energy use in Technologies ("GREET")[74] lifecycle assessment tool, and are intended to account for

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73 Jacob Wallace, *Biogas Groups, Lawmakers Jockey for Changes as EPA Nears Final Rule on eRIN Market*, WASTE DIVE (May 11, 2023), https://www.wastedive.com/news/biogas-groups-epa-erin-rfs-rng/649968/.

74 GREET, U.S. Department of Energy, https://www.energy.gov/eere/greet.

emissions associated with energy inputs.[75] California Air Resources Board's ("CARB") approach is controversial for its inclusion of avoided methane emissions for pathways that valorize animal manure into LCF.[76] In these situations, CARB compares the production of an LCF from animal manure to a counterfactual scenario in which the manure would have been otherwise lagooned—a methane-intensive manure management practice that is not a universal practice. Due to the high potency of methane, crediting avoided methane emissions from fuel production has a significant negative impact that is greater than any emissions generated in the production of the fuel.

This approach is controversial because the counterfactual may not be an appropriate benchmark and because it uses transportation sector policy to regulate agricultural sector emissions. The assumption that a large dairy farm would have otherwise lagooned its waste is not an appropriate counterfactual, as there's no demonstration that this is the default practice. It is also economically distortive: while the RNG pathway represents 1 percent of state vehicle fuel, these pathways received 17 percent of LCFS credits.

This argument that RNG avoids methane emissions only applies to a subset of RNG feedstocks. If relied on at a large scale, RNG would require the use of energy crops that can generate indirect emissions, such as those from agricultural cultivation and land use change.

Critiques of this have been well-documented elsewhere and are exhaustive.[77] A retired official from the California Air Resources Board ("CARB"), the agency that regulates the LCFS,

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75 National Grid advocates for the usage of GREET throughout its CCP.

76 Danny Cullenwald, *California's Low Carbon Fuel Standard*, KLEINMAN CENTER FOR ENERGY POLICY (Oct. 2024), https://kleinmanenergy.upenn.edu/wp-content/uploads/2024/10/KC-Paper-16-Californias-Low-Carbon-Fuel-Standard.pdf.

77 *Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States, National Academies of Sciences, Engineering, and Medicine*, THE NATIONAL ACADEMIES PRESS (2022), https://doi.org/10.17226/26402.

noted in comments on recent updates to the LCFS, "No other industry is treated as if their methane pollution is naturally part of the baseline and then lavished with large financial incentives for simply reducing their own pollution. Oil companies are not awarded large LCFS incentives for avoiding methane emissions at oil fields and refineries. Instead, they are regulated and penalized for their emissions."[78]

In recognition of these issues, CARB announced in November 2024 that it would implement a long phase-out of avoided methane crediting and implement other adjustments to reduce the LCFS's favorability towards RNG.[79] The long phase-out time horizon reflects the challenge with unwinding polices that become entrenched.

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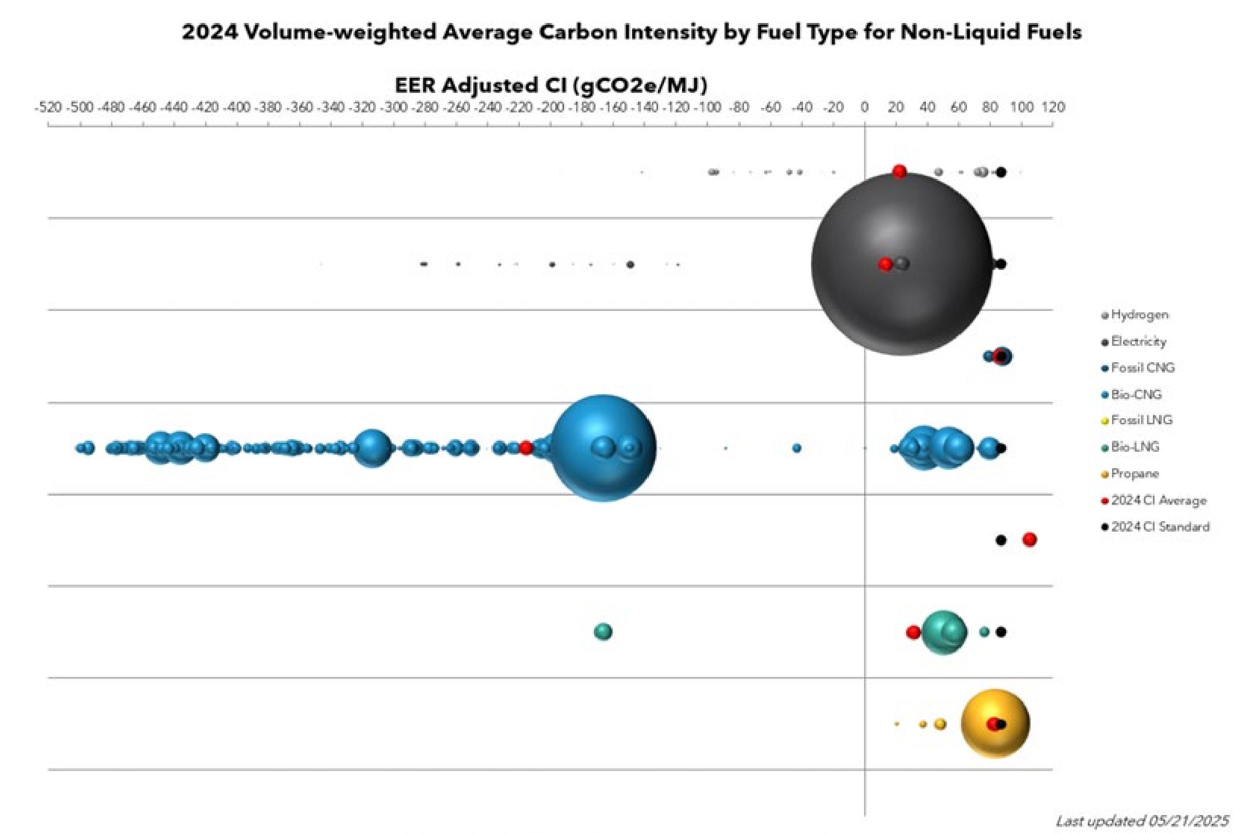
78 Jim Duffy, *Comments to the California Air Resources Board*, MIDWEST ENVIRONMENTAL ASSOCIATES (Feb. 2024), https://midwestadvocates.org/wp-content/uploads/Jim-Duffy-CARB-Letter-Feb-2024.pdf.

79 California Air Resources Board, *CARB Updates the Low Carbon Fuel Standard to Increase Access to Cleaner Fuels and Zero-Emission Transportation Options*, (Nov. 8, 2024), https://ww2.arb.ca.gov/news/carb-updates-low-carbon-fuel-standard-increase-access-cleaner-fuels-and-zero-emission.

Appendix C

Figure 13. 2024 Carbon intensities of CARB-certified non-liquid fuels Extracted from Exh. AG-1-9.



Source: [LCFS Data Dashboard | California Air Resources Board]

To CARB's credit, it is somewhat consistent with the crediting of avoided methane across fuels, and unlike the EPA, it allows for a direct-burn electric pathway. To illustrate this, I have reproduced the figure submitted by National Grid in Exh. AG-1-9 (Figure 1). The blue spheres represent bio-CNG or RNG used as transportation fuel. The negative-value black spheres two rows above are negative carbon intensities for more conventional biogas-combustion to electricity pathways. The size of the spheres represents the volume of production at that carbon intensity. The difference between the size of the negative Bio-RNG and electricity pathways reflects how various policy factors can influence the allocation of projects, including: Renewable Fuel Standard eligibility (RNG only), location (RNG can be anywhere in U.S., electricity must be interconnected with the CA grid), and greater reporting and verification requirements for electricity. Even when some pathway attributes are treated equivalently, the arbitrary treatment of others can lead to distorting outcomes.

D. National Grid's Understanding of RNG Relies on an Industry Study That Overstates the Benefits of RNG

Information Request AG-1-8 asked National Grid: "Please explain how the Company's strategy regarding low carbon fuels accounts for the fact that the Federal Renewable Fuel Standard, California's Low Carbon Fuel Standard, and other state programs create competing demand for the same limited RNG supplies." National Grid responded to the request with the following statement: "The Company does not see a conflict between its consideration of LCFs and other state programs."[80] National Grid then referenced a series of reports and information sheets developed by the American Gas Association ("AGA") and its affiliate non-profit, the American Gas Foundation ("AGF"). These include several misleading facts and analyses that apparently inform National Grid's understanding of RNG. Specifically, the response and AGA reports make the following errors:

1. National Grid and AGA overlook competing uses of feedstocks for RNG.

National Grid wrote with respect to the AGF's 2025 Renewable Natural Gas Supply Assessment: "*the study estimates the supply potential of biogenic resources from 1,628 tBtu/year to 7,061 tBtu/year.*"[81] The problem with this framing is that it neglects the fact that these resources are also available for other uses, including high-value liquid fuels (e.g., sustainable aviation fuels),

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80 *National Grid*, D.P.U. 25-41, Exh. AG-1-8.

81 American Gas Foundation, *Renewable Natural Gas Supply Assessment* (Jul. 2025), https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf.

electricity, chemical feedstocks and fertilizers, and carbon capture and storage. The AGF assessment does acknowledge this limitation: "This RNG feedstock inventory does not estimate resource availability—in a competitive market, resource availability is a function of factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development."[82]

A competitive market environment that efficiently allocates resources should favor the production of higher-value products from analyzed feedstocks over RNG. A competitive market was modeled in the Roadmap Pathways Report's which demonstrated that RNG would be an inferior use of these feedstock resources.

2. National Grid's response relies on an AGA study that incorrectly calculates carbon abatement costs due to an obvious error.

The information request also references a chart and data from another AGA study, *Building for Efficiency: Home Appliance Cost and Emissions Comparison*,[83] that compares RNG heating to home heating using several specious assumptions (Figure 14 below). The AGA study makes an error when calculating the abatement cost for RNG relative to fossil gas. The abatement costs represent the cost premium of RNG over fossil gas, divided by the emissions reductions achieved through the switch to RNG. The error the AGA makes here is that it uses the *residential* cost of gas (fossil supply plus distribution)[84] in relation to the *supply* cost of RNG to calculate the RNG premium. The report should have been consistent in using either the supply cost of each source or

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82 *Id.* at 11.

83 AGA, *Building for Efficiency: Home Appliance Cost and Emissions Comparison* (Dec. 2024), https://www.aga.org/wp-content/uploads/2025/01/AGA-Report_2024_Building-for-Efficiency-08-MV.pdf.

84 *Id*. at 39, App. B, Average Monthly Residential Natural Gas Prices for 2024 $/MMBtu.

the supply plus delivery cost; both result in the same premium because the distribution cost should be identical.

Figure 14. AGA figure referenced by National Grid in AG-1-8 at 4.

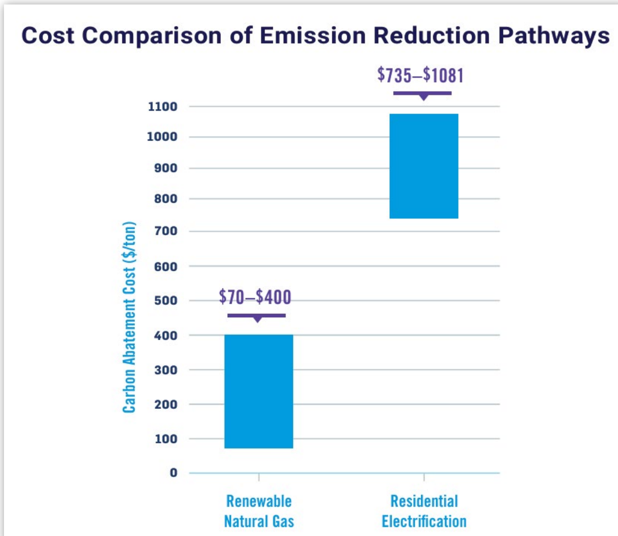
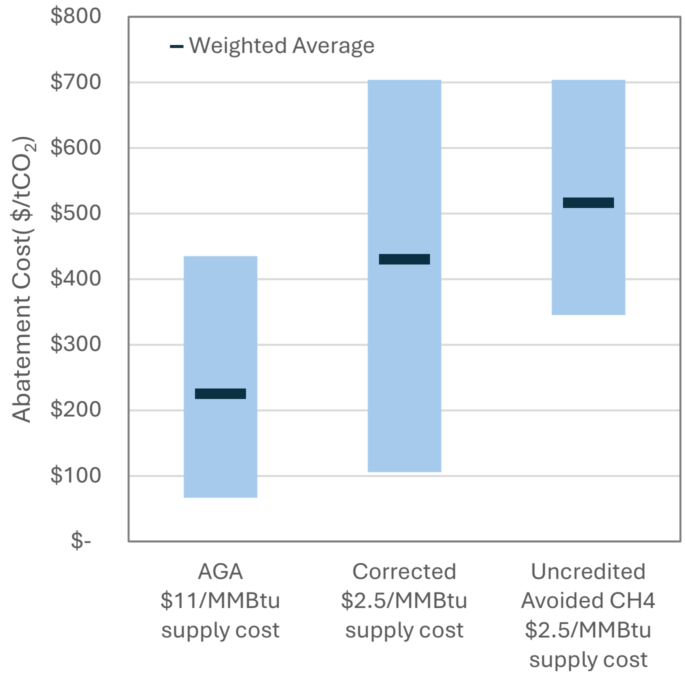


Figure 15 below recreates this calculation, as shown in the left-most column, which generates a range of \$67 - \$435 per tCO_2. The next column uses the same calculation, this time with a \$2.5 per MMBtu supply cost, raising the range of RNG abatements from \$106-\$704 per tCO_2. The third column removes the avoided methane credit from the calculation for comparison purposes.

Figure 15. Assessment of RNG supply costs.



3. National Grid's response relies on an AGA study that selectively uses LCA to greenwash RNG.

Overlooking this error, National Grid further notes: "It is also important to note the cost savings associated with the use of RNG; the study shows that over the course of 15 years, the average homeowner can save up to $7,500 compared to having an all-electric home. These cost savings are accompanied by realized emissions reductions with only modest use (12-20 percent) of RNG."[85] The customer, in this instance, still uses 80 percent to 88 percent fossil gas, because the AGA report utilizes the avoided methane crediting assumption to produce outcomes that cast RNG as an economically favorable decarbonization strategy: "While RNG is still an emerging and growing market, blending RNG can save significant emissions at a low cost per ton because

85 *National Grid*, D.P.U. 25-41, Exh. AG-1-8.

of the avoided emissions."[86] As discussed above, this is neither an appropriate nor a scalable assumption for two reasons.

An electric pathway can also use this approach to generate a more favorable outcome. To illustrate how the AGA claim is selective, we can compare two heating pathways that start with manure. In both cases, the manure is converted to biogas in an anaerobic digester, which is assumed to have a 1 percent methane leak rate, and an additional 18.5 percent of the produced biogas is used to power the digester itself.[87]

In the first electric pathway, the biogas is burned directly to generate electricity at a 33 percent conversion efficiency; the resulting electricity is distributed on the grid (with 4.5 percent transmission and distribution losses) and used to power a heat pump with a coefficient of performance (COP) between 2.6 and 3.2 (as assumed by the AGA report). All told, to deliver 1 MMBtu of heating service to a home, this pathway requires the use of between 51 and 63 kg of biogas—assume for simplicity that this biogas would have otherwise escaped from a manure lagoon.

The second gas pathway upgrades the biogas to RNG for use in a conventional furnace. Upgrading is an energy-intensive process, requiring an additional 5.8 percent of the fuel and also resulting in a leakage of about 2.8 percent of the input biogas. The now pipeline-quality fuel is injected into the gas system and delivered to the end user. We can also consider end-use furnace efficiencies of 80 percent and 95 percent, representing the different technologies available to homeowners. With this pathway, delivering 1 MMBtu of heating service requires an input of

86 AGA, *Building for Efficiency: Home Appliance Cost and Emissions Comparison*, at 24.

87 These values are pulled by Groundwork Data from the GREET Model to be consistent with the AGA report.

between 60 and 73 kg of biogas. Again, assume for simplicity that this biogas would have otherwise escaped from a manure lagoon.

The electric pathway uses less biogas (approximately 20 percent to 25 percent) for the same heating output. It is universally understood that using less of a limited resource to achieve an outcome is better than using more. The AGA and National Grid conclude otherwise: “These results also provide a surprising conclusion: Increasing RNG blends increases the overall cost-effectiveness of natural gas emissions reductions.”[88] This conclusion is absurd because it rests heavily on the fallacy of the avoided methane credit. Taken further, it would imply that a less efficient furnace is preferable for a home because it uses more RNG, which avoids more methane. The electric pathway is preferable because it generates more energy from the resource—presumably without the expense and energy inputs associated with RNG purification. The AGA’s use of LCA is selective and cannot withstand scrutiny.

The AGA’s conclusion also neglects the lost methane through the gas system. The electric pathway destroys the methane soon after it is produced; the gas pathway preserves the methane through upgrading, transmission, and distribution to appliance use in buildings–more opportunities for leaks. While these also happen with fossil methane, a fair life cycle assessment that attributes avoided manure methane should also credit electric strategies with avoided methane from such system leaks.

National Grid’s and the LDCs’ broader argument for an expansive LCA that recognizes avoided methane emissions is an implicit argument for the fungibility of emissions credits. If the

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[88] AGA, *Building for Efficiency: Home Appliance Cost and Emissions Comparison,* at 35 (emphasis included).

LDCs contend that avoided methane emissions can be used to offset fossil gas use, it follows that a large number of options could be used to achieve the same goal. For example, a non-energy solution to manure management (e.g., spreading, composting) that is not lagooning should subsequently be eligible to produce credits for the heating sector. Alternatively, a load-following direct-burn anaerobic digestor system that displaces peak gas or coal loads out of state should also be able to generate similar credits. Such crediting need not stop there; electrification efforts could be credited with avoided methane emissions from the well-head or avoided methane incentives could be given for neighborhood-scale electrification projects that enable the retirement of leak-prone pipe.

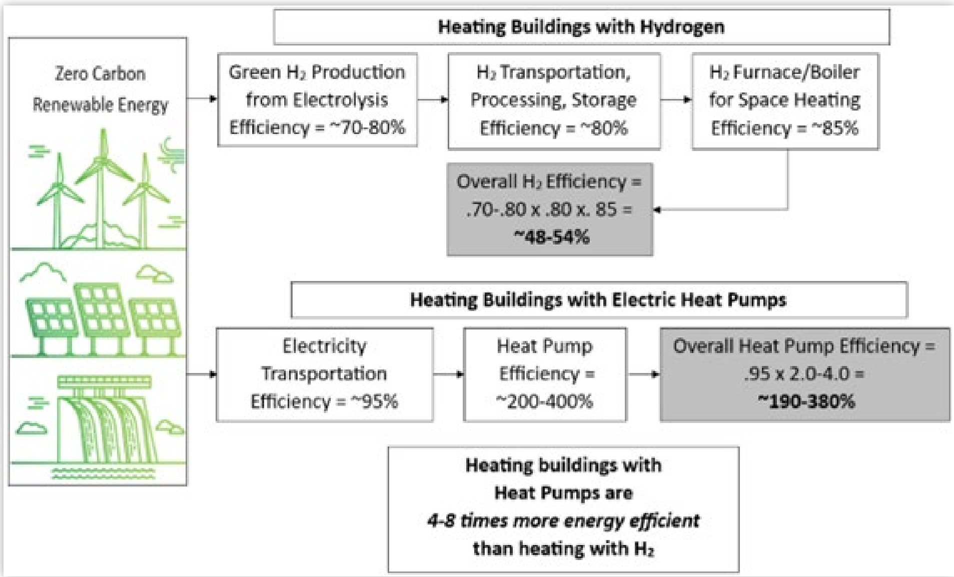
The AGA's use of avoided methane greatly distorts their cost comparisons. Because such avoided methane is not scalable, it is helpful to put the cost of RNG production in a simple and straightforward context. RNG will carry a $25 per MMBtu premium over fossil gas. For a typical house that requires 80 MMBtu of gas per year, this would result in an additional $30,000 cost for the consumer over a 15-year period.

E. Hydrogen Faces Distinctive Challenges as a Pipeline Fuel

1. Hydrogen's production and use involves significant fuel cycle inefficiencies.

For hydrogen to be a zero-carbon fuel, the energy to produce hydrogen using electrolysis must be supplied from zero-carbon renewable energy. However, there are multiple energy losses in the process to produce hydrogen. Figure 16 below illustrates the energy efficiency of heating homes using hydrogen compared to electric heat pumps. There are multiple inefficiencies in the production, transport, processing, storage, and combustion of hydrogen. Taking into account losses and the efficiency gains of heat pumps, heating buildings with hydrogen would require 4 to 8 times more renewable energy production than heat pumps.

Figure16. Efficiency of electric heat pumps vs hydrogen for heating buildings.



2. Hydrogen's chemical properties make it poorly suited for existing gas distribution systems.

Hydrogen has one-third the energy content per volume compared to natural gas. This means that to supply the same energy to customers, the volumetric flow rate of pure hydrogen must be about 3 times the flow rate of natural gas.[89] These higher flow rates are not possible with the existing gas system, which means extremely costly installation of new transmission and distribution pipelines, compressor stations, regulators, metering, and other equipment to address the needed large increase in system flow capacity.

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89 Anna Bella Galyas, et al, *Effect of hydrogen blending on the energy capacity of natural gas transmission networks*, INTERNATIONAL JOURNAL OF HYDROGEN ENERGY (2023) https://doi.org/10.1016/j.ijhydene.2022.12.198.

Most hydrogen proposals from gas utilities blend hydrogen with natural gas to keep the hydrogen blend percentage at low levels, such that embrittlement,[90] leakage, and capacity issues are less of a concern. There has been significant research on the percentage of hydrogen that can be blended into the natural gas system to avoid costly integrity and leakage prevention investments. The research is still ongoing with blends of up to 5 percent hydrogen, by volume, likely not requiring upgrades, and other research assessing if it is possible to blend hydrogen up to 20 percent without costly system upgrades. The pilots typically are on relatively small gas systems or closed test loops to gain data on these lower hydrogen blends. The lower blend levels will reduce the need for costly capacity investments. However, each gas system is unique. Systems with spare capacity under maximum flow conditions may not need capacity investments, while other systems without spare capacity would need investments. The research here, however, indicates that there is still significant uncertainty in acceptable blend levels and clearly illustrates that determining appropriate hydrogen blends for use in pipelines has not been resolved. This raises questions about whether the uncertainty of hydrogen blending can be resolved in time to be an effective solution to a net-zero carbon energy system.

Because hydrogen has only one-third the heating value of natural gas at a 5 percent blend of hydrogen would reduce carbon emissions by less than 2 percent. A 20 percent blend would reduce carbon emissions by about 7 percent (see Figure 17 below).

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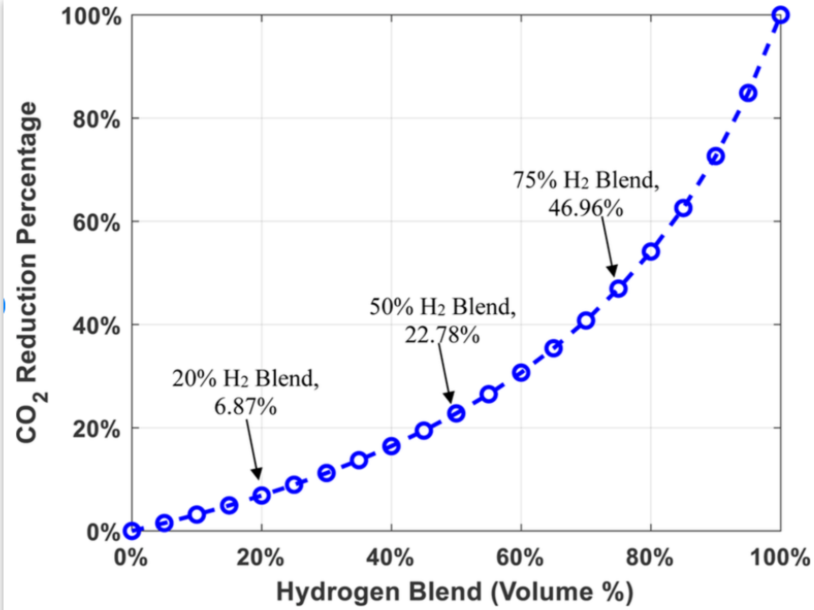
[90] The method and effectiveness of adding liners inside the pipelines to protect the pipe material from hydrogen this approach is unknown. There are proposals to upgrade pipe component connections to prevent hydrogen leakage. This would be a very costly effort given the large amount of welds, joints, gaskets, and complex equipment within networks designed for natural gas. There have been some initial discussions of creating hydrogen gas networks or hubs in locations where there is a relatively high density of hard-to-electrify customers, but these approaches are extremely costly and add to the high cost of producing hydrogen described above.

Figure 17. CO2 Reduction at hydrogen and natural gas blend levels



CO2 Reduction with respect to hydrogen and methane blend percentages, for example, if methane is blended with H2 at 20%, 50%, or 75% by volume, the carbon emission reductions per unit energy of the blended gas will be approximately 7%, 23%, and 47%, respectively.

As shown, hydrogen blending levels of 5-20 percent would have a minimal impact on carbon emissions and would fall far short of a net zero energy system. Reduction of carbon emissions by less than 2 percent to about 7 percent is not a serious proposal for the reduction of carbon emissions when compared to the elimination of carbon emissions from electrification. In addition to the minimal reduction in carbon emissions, there would be significant costs for hydrogen electrolysis facilities, incremental renewable energy facilities, hydrogen blending facilities, increased leakage detection, hydrogen transport and storage losses, and some investments to address integrity and leakage, and some capacity investments.

3. Most independent studies find hydrogen has no significant role in building heating.

A 2024 meta-review of 54 independent studies on hydrogen heating for buildings found scientific consensus on multiple important points.[91] All studies found that hydrogen had no significant role for building space or water heating. All studies found hydrogen to be more costly than electric heat pumps or district heating. Further, the study stated, "The scientific evidence does not support the widespread use of hydrogen for heating buildings. This is because it is less efficient, more costly, and more environmentally harmful than alternatives such as heat pumps and district heating."

4. The U.S. Department of Energy Hydrogen Roadmap finds that H_2 has a "low potential" for decarbonizing building heat.

The U.S. Department of Energy's 2023 Hydrogen Roadmap ("Hydrogen Roadmap") underscores the limited viability of hydrogen in gas distribution systems. The Hydrogen Roadmap prioritizes strategic, high-impact applications of clean hydrogen—such as in industrial processes, heavy-duty transportation, and energy storage—but notes that for blending with existing natural gas networks, "costs must decline considerably to be economically viable." Figure 18 below compares the potential of hydrogen to support decarbonization in a number end uses and shows that blending for building heat has a "low priority."

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91 Jan Rosenow, *A meta-review of 54 studies on hydrogen heating*, CELL REPORTS SUSTAINABILITY, Jan. 26, 2024, doi://10.1016/j.crsus.2023.100010.

Figure 18. Evaluation of the role of hydrogen in various end-uses by in the U.S. National Clean Hydrogen and Roadmap, June 2023 (Figure A, Page 95).[92]

Largest long-term H2 feedstock TAM **Role in decarbonization:** Strong potential – Low potential

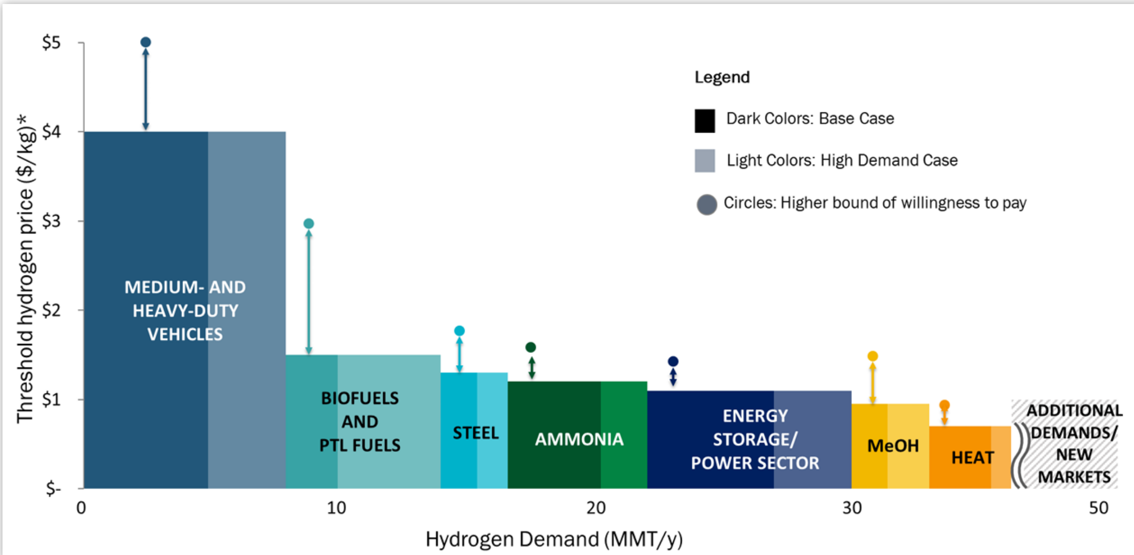
Sector	End-use	Role of H2 in decarb.	Description of switching costs	H2 feedstock TAM[1], $ billion 2030	2040	2050	H2 market size with full adoption[2], $ billion 2030	2040	2050
Industry	Ammonia		**Low:** Process currently uses fossil-based H2, hydrogen supply feed in place	4-10	4-11	5-12	4-10	4-11	5-12
	Refining		**Low:** Hydrogen supply feed in place	6-8			6-8		
	Steel		**Variable:** Highly dependent on current plant configuration and feedstock, may also include hydrogen distribution infrastructure		4-7	4-8	15-30	18-35	20-40
	Chemicals-methanol		**Variable:** Can limit switching costs by adding CCS to SMR, other approaches more costly with higher unit cost savings		2-6	3-7	5-12	5-12	6-14
Transport[1]	Road[3]		**High:** New vehicle power trains with fuel cells, refueling stations & distribution infrastructure	0	25-30	40-55	90-125	110-140	120-160
	Aviation fuels		**Moderate:** Fuel conversion / production facilities		5-15	10-30	8-20	10-25	10-30
	Maritime fuels[4]		**High:** New ship engines, port infrastructure & local storage, and fuel supply, storage, and bunkering infrastructure in ports	< 1	4-10	8-20	5-15	5-15	8-20
Heating	NG blending for building heat[5]		**Variable:** Will depend on pipeline material, age, and operations (e.g., pressure); requires testing for degradation and leakage	0	0	0	2-3	2-3	2-3
	Industrial heat		**Variable:** Dependent on extent of furnace retrofits required	0	1-3	2-5	7-10	7-10	7-10
Power	High-capacity Firm – 20% H2 (Combustion)[6]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	< 0.2	< 0.1	< 0.1	4-6	5-8	8-12
	Power – LDES[7]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	0	4-6	8-11	*Varies based on cost-downs in other LDES technologies and composition of grid*		

1. Represents the market size for clean hydrogen feedstocks in each end use; calculated by multiplying the clean hydrogen in the "Net zero 2050 – high RE" scenario by range of willingness to pay by end use reported in the DOE National Hydrogen Strategy and Roadmap; dispensing costs are subtracted from the road transport TAM and market size with full adoption
2. Represents the maximum market size if the hydrogen-based solution had 100% share of each end use
3. H2 feedstock TAM uses H2 demand from the DOE National Hydrogen Strategy and Roadmap assuming both medium- and heavy-duty trucks; H2 market size with full adoption is based on energy usage from Class 8 long-haul and regional trucks, which represent the significant majority of all medium- and heavy-duty truck energy consumption

Figure 19 below emphasizes why hydrogen is unlikely to play a major role in building heat decarbonization. Sectors positioned on the left side of the chart—such as heavy industry and long-haul transportation—demonstrate a higher willingness to pay for hydrogen, making them more competitive recipients of limited hydrogen supplies. Unless hydrogen production costs decline dramatically, these sectors will continue to outcompete building heating applications.

92 *Id*. at 95 (Figure A).

Figure 19. Scenarios showing estimates of potential clean hydrogen demand in key sectors of transportation, industry, and the grid, assuming hydrogen is available at the corresponding threshold cost in the U.S. National Clean Hydrogen and Roadmap, June 2023 (Figure 11, Page 20).[93]



5. Local research on hydrogen demonstrates high cost and limited opportunity for scaling.

In 2020, Pacific Northwest National Laboratory published a techno-economic study of 82 design cases for a power-to-gas system that produces either hydrogen gas or synthetic RNG at a local Massachusetts municipal gas and electric utility (Figure 20 below).[94] Only 6 cases exhibited a positive return on investment, which was due to assumed zero energy input costs or a high market price for hydrogen. The findings revealed that nearly all scenarios, including hydrogen injection into the gas grid, exhibited poor financial viability. Most cases showed unfavorable payback periods or required highly optimistic assumptions, such as zero-cost input energy or elevated hydrogen market prices, to achieve a positive return on investment. These results underscore the

93 *Id*. at 20 (Figure 11).

94 P. Balducci, et al., *Power-to-Gas System Valuation*, PACIFIC NORTHWEST NATIONAL LABORATORY, (Jun. 2020, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-ACT-10095.pdf.

economic challenges of scaling hydrogen-based solutions for local energy systems, particularly in the context of building heat decarbonization.

Figure 20. Results of PNNL Power-to-Gas System Valuation Study in Holyoke Massachusetts (May 2020): Table ES-1, page iii. Hydrogen blending scenarios are highlighted (6a -6c).

Table ES.1. Results by Scenario Examined in this Report

Case #	Case Definition	20-Year PV Benefits ($Millions)	20-Year PV Costs ($Millions)	ROI Ratio
1	Hydrogen for transportation fuel only	5.6-5.7	21.5-22.1	0.26
2	Hydrogen for transportation fuel and natural gas injection	5.6-6.2	21.6-22.4	0.25-0.28
3	Hydrogen for transportation fuel and natural gas injection, with additional revenue from varying P2G unit electrical load to provide frequency regulation (base case)	8.5-15.7	23.2-29.0	0.37-0.54
4a	Industrial gas sold at $2/kg	10.6-16.7	25.6-30.5	0.41-0.55
4b	Industrial gas sold at $4/kg	12.3-18.5	25.7-30.7	0.48.-0.60
5a	Doubling of demand for transportation fuel	14.8-20.9	24.4-29.3	0.61-0.71
5b	Tripling of demand for transportation fuel	21.2-26.3	25.8-29.9	0.82-0.88
5c	Transportation fuel price of $4/kg	6.0-13.3	23.1-29.0	0.26-0.46
5d	Transportation fuel price of $10/kg	10.9-18.2	23.2-29.0	0.47-0.63
6a	Allow 1% hydrogen injected into natural gas grid w/o methanation	8.5-15.7	23.0-28.9	0.37-0.54
6b	Allow 2% hydrogen injected into natural gas grid w/o methanation	8.6-15.7	23.1-28.9	0.37-0.54
6c	Allow 5% hydrogen injected into natural gas grid w/o methanation	8.7-15.7	23.2-28.9	0.38-0.54
7	Assume that energy prices are zero with no emissions from electricity used to power the electrolyzer from March 19-June 20	11.8-19.2	23.6-27.0	0.50-0.71
8a	Carbon tax at $50/ton	16.3-31.3	29.4-39.9	0.56-0.78
8b	Low carbon fuel standard at $2.5/kg	10.5-17.8	23.2-29.0	0.45-0.61
9a	P2G unit paying retail prices, served by a distribution utility	11.0-13.6	25.0-27.0	0.44-0.50
9b	P2G unit paying retail prices, served by a municipal utility	11.1-13.5	24.9-26.8	0.45-0.50
10a	Case 3 with 5 MW P2G unit	7.4-10.5	13.6-16.2	0.54-0.65
10b	Case 5b with 5 MW P2G unit	20.1-21.7	16.8-18.1	1.19-1.21
10c	Case 8a with 5 MW P2G unit	11.0-18.2	16.3-21.6	0.68-0.84
10d	Case 7 with 5 MW P2G unit	9.0-12.2	13.7-15.2	0.65-0.80
11	Zero energy prices and emissions 3/19-6/20 with carbon tax and double transportation demand	26.7-40.1	28.8-36.2	0.93-1.12