Pipeline Extension Allowances and the Future of Gas in Massachusetts

A Technical Comment in Response to the Massachusetts Department of Public Utilities' Request for Comments by Interested Parties on the Topic of Line Extension Policies of Gas Local Distribution Companies

in the

Department's Investigation into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals (D.P.U. 20-80)

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ABBREVIATIONS

20-80 Pathways Report	*The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report Part I: Technical Analysis of Decarbonization Pathways*[1]
BERDO	Building Energy Reporting and Disclosure Ordinance (Boston)
BEUDO	Building Energy Use Disclosure Ordinance (Cambridge)
CIAC	Contribution in Aid of Construction
DPU	Department of Public Utilities (Massachusetts)
EGMA	Eversource Gas Company of Massachusetts
EIA	Energy Information Administration
GREC	Gas System Enhancement Reconciliation
GSEP	Gas System Enhancement Program
GWSA	Global Warming Solutions Act
HVAC	Heating, Ventilation and Air Conditioning
IECC	International Energy Conservation Code
IRA	Inflation Reduction Act
IRR	Internal Rate of Return
LDC	Local Distribution Company
LDAF	Local Distribution Adjustment Factor
MCF	Thousand Cubic Feet
MMBtu	Million British Thermal Units
NPA	Non-Pipeline Alternative
O&M	Operations and Maintenance
PHMSA	Pipeline and Hazardous Materials Safety Administration
Roadmap Act	*An Act Creating A Next-Generation Roadmap For Massachusetts Climate Policy*, St. 2021, c. 8, § 15, codified at G.L. c. 25, § 1A
RDAF	Revenue Decoupling Adjustment Factor
WACC	Weighted Average Cost of Capital

[1] Energy and Environmental Economics, Scott Madden Management Consultants. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Pathway Report--Technical Analysis of Decarbonization Pathways*. (March 2022). /fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633269

Executive Summary

In October 2020, the Massachusetts Department of Public Utilities opened an investigation into the role of local gas distribution companies (LDCs) in achieving the Commonwealth's 2050 climate goals (D.P.U. 20-80). Throughout the course of the investigation, several parties raised concerns about the LDCs' line extension policies and practices.

New gas customers requiring a new connection, or line extension, to the gas system are granted an allowance covering part or all of the construction cost under the assumption that the allowance is recovered through future revenues from the customer. The customer is responsible for costs beyond the allowance. This practice has been encouraged with the assumption that adding new customers to the gas system will lower the average service cost for all customers *after the allowance has been recovered*. This reasoning assumes that so long as the practice of granting allowances ensures that existing customers do not subsidize new customers, then expansion would be in the public interest. Further, the promise to reduce emissions and expand access to a historically more affordable heating fuel bolstered the case that the expansion of gas service benefitted broader public interests.

However, in its comments for the 20-80 investigation, the Office of the Attorney General observed that there is "no uniform model or costing matrix for determining the cost/benefit of line extensions or any indication that LDCs are considering the impact of the State's GHG reduction requirements in making their determinations." Several other commenters noted that allowances incentivize the lock-in of gas assets and gas consumption when compliance with the Commonwealth's emissions limits requires a substantial reduction in the consumption of pipeline gas. The LDCs' independent consultant also recognized the increasing risk that the allowances may not be recovered.

In the Department's December 6, 2023 Order on Regulatory Principles and Framework (D.P.U. 20-80-B), the Department expressed its desire to further investigate line extension policies and practices to better understand "the number of de facto free extension allowances," "whether current models and policies accurately reflect the anticipated income and time frame over which the capital investments will be recovered," and "whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions." On June 14, 2024, the Department of Public Utilities ("Department") issued a memorandum requesting that the LDCs provide testimony describing their line extension practices and inviting interested parties to comment on the practices and issues raised by the Department.

This report responds to that request for comment. It finds that the LDCs' line extension policies and practices are inconsistent across LDCs, increasingly inconsistent with the principle that existing customers should not subsidize new customers, and inconsistent with state climate policy.

Since 2018, approximately 80% of new service-only connections have been provided at no cost. The average cost of adding new customers was $9,000 in 2023, totaling over $160 million across the Massachusetts LDCs. Our analysis finds that average new customer costs have risen by 50% between the 2020-2021 and 2022-2023 averages due to recent upward pressure on labor and material costs.

At the same time, the policy landscape is changing, and gas faces unprecedented competition. New construction is increasingly efficient, and new building codes in over 40 gas-served municipalities require electrification pathways for customers, even if they start with gas. Gas is no longer the only viable alternative to oil, with heat pumps now offering customers affordable heating, cooling, and enhanced comfort. The consequence of this is that, on average, gas demand will decline, and customers will increasingly depart from the gas system. This would leave some allowances unrecovered and obviate the long-term benefits of growing the customer base. Those most burdened by this would be those with the least agency to leave the system.

This situation is not hypothetical. In its response, National Grid noted: “During the last 12-24 months, the Company is seeing a small but growing number of requests to install new gas services for limited use, supply backup or for a temporary period of time.” It gave examples of multifamily developments requesting service for common areas and “large C&I customers who require a gas service for a limited number of years to allow for sufficient electric capacity to be built to fully electrify their buildings.” The future of gas demand will be increasingly inconsistent and significantly lower than today. Our analysis confirms this by showing that new connections have far lower gas demand than existing ones.

We observe inconsistent allowance practices across LDCs that lead to differences of over $2,000 for a typical residential customer. For some time, most LDCs have been granting no-cost allowances to customers within a certain distance of a main (e.g., 100 feet). We find that under conservative connection costs estimates, excessive allowances are likely being granted under this practice.

Conclusively answering the question of whether existing customers are subsidizing new customers rests on fundamental assumptions surrounding payback periods, discounting, and expense allocation. Ultimately, inconsistency in reporting, data, and allowance calculation methodology makes this determination difficult. However, we note that the observed variability in practice demonstrates that current methodologies are arbitrary and that there is a growing risk that existing customers subsidize new customers. Thus, current practice is no longer in the public interest of existing ratepayers.

We also find that allowances are no longer in the broader public interest with respect to climate and affordability considerations. All-electric new construction has achieved cost parity with gas. Full or partial electrification of oil-heated homes achieves greater emissions reductions than an oil-to-gas conversion. We observe that several gas utilities incorrectly still consider oil-to-gas conversions to be aligned with State climate policy. We also note that given the long-term challenges facing the gas system, electrification of heating coupled with efforts to lower the average cost of electric delivery is the lowest risk strategy for preserving affordability in heating.

We make several additional observations: new connections in parts of the system suitable for targeted electrification should be avoided to align with other Department directives; industry concerns that the reduction or elimination of allowances would represent a subsidy from new customers to existing customers are unfounded due to the industry’s dismissal of long-term risks to the gas system; and reducing allowances will not harm the workforce or adversely affect the housing crisis.

We also evaluate several potential changes to line extension policies that have been enacted in other states. Ultimately, we find that the Department has sufficient grounds to incrementally reduce allowances or even to eliminate them altogether.

CONTEXT AND OVERVIEW OF THE REPORT

On June 14, 2024, the Department of Public Utilities ("Department") issued a memorandum[2] concerning the Line Extension Policies of Gas Local Distribution Companies ("LDCs"). This memorandum was part of the Department's ongoing investigation into the role of gas LDCs in achieving the Commonwealth's 2050 climate goals (D.P.U. 20-80).

The memorandum summarized the Department's December 6, 2023, Order on Regulatory Principles and Framework[3] and noted the Department's desire to further investigate line extension policies and practices. In Order 20-80-B, the Department stated that it would examine and revise the standard for investments to serve new customers and instruct the LDCs to begin reviewing their tariffs, policies, and practices related to new service connections.

In its memorandum, the Department formally issued information requests to the LDCs for testimony, documentation, and data describing their line extension practices. The LDCs submitted responses to the request on August 13, 2024.

In the memorandum, the Department also requested comments from interested parties on the following three questions:

1. *Do the LDCs' current models and policies accurately reflect the anticipated income and timeframe over which capital investments to serve new customers will be recovered? Provide an explanation and include supporting documentation.*

2. *Are LDCs' current practices inconsistent with state policies regarding GHG emission reductions by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions? Provide an explanation and include supporting documentation.*

3. *Are there other issues that the Department should consider in developing a common framework for new service connections?*

This technical comment is organized to assist interested parties in their comments, provide the Department with an analysis of the LDCs' responses, and help align their line extension practices with the state's climate goals. The comment is organized as follows:

We start by providing **background** on the gas system's historical growth, the role of line extension allowances in supporting growth, the evolving building landscape, and how allowances should be considered in the context of the evolving landscape.

We then respond to the **Department's first question on the costs of line extensions**. We review estimates for the cost of line extension projects and future customer revenues. We evaluate the application of the standard practices in which allowances are granted based on proximity to the system

[2] *Line Extension Policies of Gas Local Distribution Companies* (Memorandum), D.P.U. 20-80, June 14, 2024, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19211932
[3] D.P.U. 20-80, *Order 20-80-B*

(colloquially known as the “100-foot rule”). We then evaluate the LDCs’ calculators to determine customer contributions and allowances. Increasing project costs and declining future customer demand will necessitate increasing future customer contributions to maintain the principle that existing customers should not subsidize new customers.

Next, we address the **Department’s second question on the alignment of line extension practice with climate policy**. We begin by reviewing the LDCs’ responses and comparing their current practices with the goals of Massachusetts state climate policy. We observe that historically, line extension policies were justified by the Department and LDCs because the displacement of tank fuels and electric resistance heating incrementally lowered emissions. However, we emphasize that the gas system is transitioning to a declining industry, and new technology has enabled practical alternative strategies to substantially reduce or eliminate emissions. We use this observation to note that line extension allowances are likely no longer compatible with the public interest’s climate consideration as they are insufficient to deliver reductions in greenhouse gas emissions necessary to meet statewide greenhouse gas emissions limits and sub-limits. Further, given the long-term challenges facing gas, expansion no longer delivers affordability benefits in the public interest.

Following this, we address the **Department’s third question, inquiring about other considerations**. We critique the gas industry’s perspective, consider workforce implications, assess impacts on new construction and customer energy costs, review proposals for line extension reform, and provide considerations for implementation.

Finally, this report **concludes** by summarizing the LDCs' practices and the findings of this report. We conclude that there is sufficient rationale to justify incremental or comprehensive changes to line extension policy and practice.

Background

Historical Context

Massachusetts' gas system has grown steadily for the past two centuries, enabling a steady lowering of fixed costs per customer. The state's first gas company, the Boston Gas Light Company, was chartered in to provide street and, eventually, indoor lighting.[4] By the end of the century, several other gas light companies sprung up, sometimes with overlapping territories. The arrival of electricity in the late 19th century threatened these companies. However, they adapted by shifting their business model, and by 1885, state law needed to be updated to allow for the provision of gas for "heating, cooking, chemical and mechanical purposes."[5] At this time, the average gas cost was $1.78 per million cubic feet,[6] adjusted for inflation and the lower calorific value of the early coal gas, this is equivalent to over $103 per MMBtu today. By 1919, growth, production improvements, and competition lowered costs to $1.09 per MCF or $37 per MMBtu in today's dollars.

For most of the 20th century, gas was more expensive than coal or fuel oil because of its high production and delivery costs. It grew because it offered new value propositions for customers. Gas was reliable and convenient for heating—not requiring refilling a coal furnace or an oil tank, a useful feature in dense cities. It also offered customers new services such as cooking, clothes drying and even refrigeration. Early gas customers were even offered free appliances for signing up for gas.[7] A cost that would be paid for through the customer's subscription. Once pipes were laid in the streets, local gas distribution companies ruthlessly marketed gas service to prospective new customers.

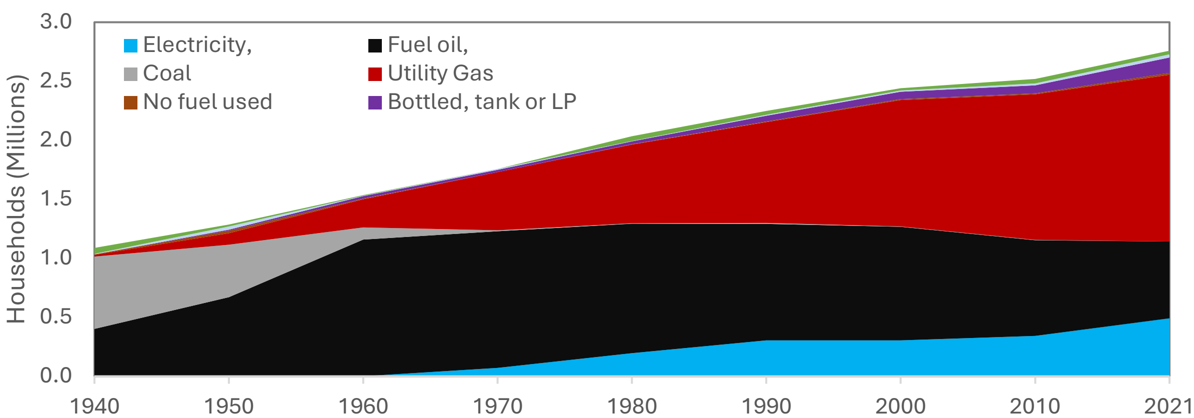

Figure 1. Household heating fuel use in Massachusetts. Source: Historical Census of Housing Tables House Heating Fuels (1950-2000)[8] and American Community Survey Table B25040 (2010 & 2021).[9]

[4] Hatheway, A. W. & Speight, T. B. *Manufactured Gas Plant Remediation: A Case Study*. (CRC Press, 2017) at 16
[5] Ibid. at 186
[6] Ibid. at 194
[7] Keating, S., *Illuminations: The History of the Boston Gas Company 1822-2000*. (Boston Gas Company, 1999)
[8] U.S. Census Bureau "*Historical Census of Housing Tables: House Heating Fuels*" (2000) https://www.census.gov/data/tables/time-series/dec/coh-fuels.html
[9] U.S. Census Bureau "*American Community Survey: Table B25040*" (2024) https://data.census.gov/table/ACSDT5Y2021.B25040

The post-World War II construction and economic boom sparked a broader effort to grow the gas system (Figure 1). At the start of the 1950s, an effort was launched to connect the Bay State to the gas fields of Texas via the Tennessee Gas and Algonquin pipelines. By 1960, nearly all towns had undergone the appliance-by-appliance conversion from town gas to natural gas.

This granted customers access to lower-cost gas, but it ultimately took a breakthrough advancement in gas well drilling to lower gas supply costs to a level that, combined with distribution system costs, made gas more economical than oil for households in the region by 2010 (Figure 2).

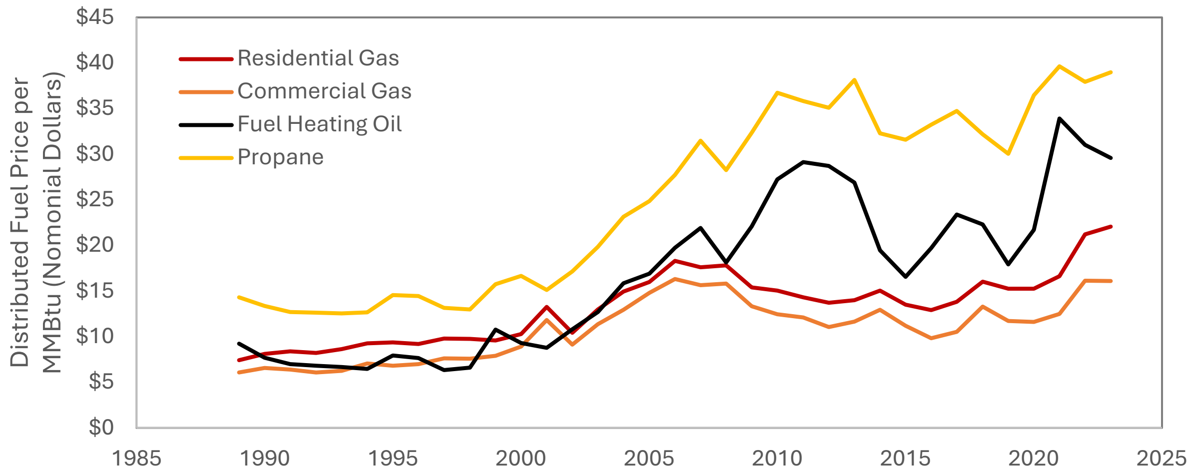

Figure 2. Prices of delivered fuels. Source: U.S. EIA Natural Gas[10] and Delivered Fuel Prices[11]

While the number of gas customers grew six-fold from 1960 to today, actual consumption only tripled (Figure 3 & Figure 4). Since 2008, gas demand has largely been flat in the residential sector, while the commercial and industrial sectors have experienced modest demand growth. This reflects Massachusetts' aggressive energy efficiency programs, which are pursued to ensure affordability, reduce emissions, and avoid additional demand on the constrained transmission pipes that deliver gas to the region.

This evolution did not happen organically. At every step, the system was guided by some level of regulation. First, gas systems were regulated to ensure safety; then, as distribution companies began to compete for customers and street space to lay pipes, regulators stepped in to consolidate these companies into monopolies. Regulators, in turn, oversaw the spending of these monopolies to ensure that customers were being treated fairly. For most of the 20th century, even if gas service was more expensive than oil or coal, regulators took steps to ensure it would be as affordable as practical. As the system grew, regulators became deferentially supportive of system growth, recognizing that the growth in customers was in the ratepayer and public interest as it spread out the fixed costs of the gas system, making utilization of the system more affordable for everyone.

[10] U.S. EIA, Natural Gas Prices, https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_m.htm
[11] U.S. EIA, Weekly Heating Oil and Propane Prices, https://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_nus_m.htm

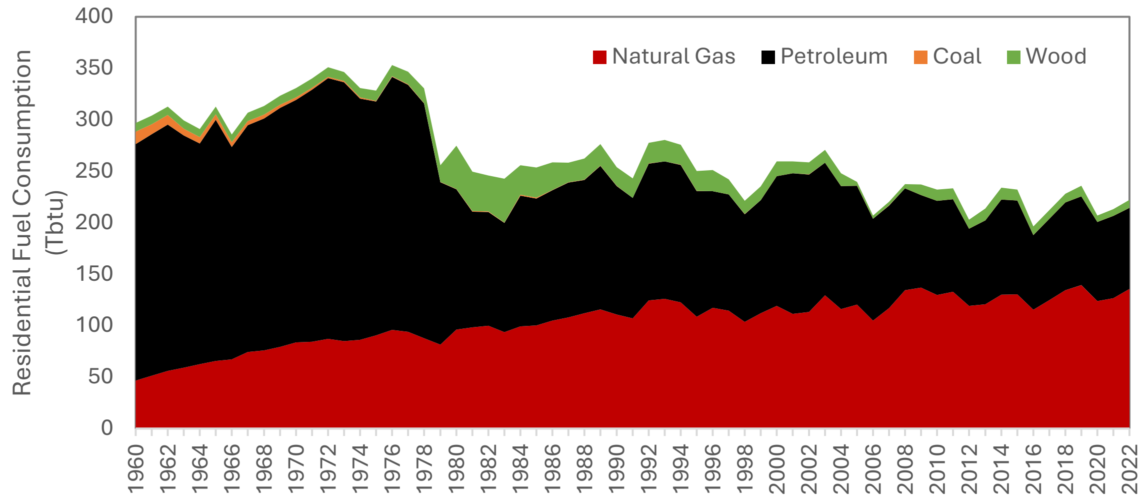

Figure 3. Massachusetts residential sector energy consumption by energy source. Source: EIA State Profile[12]

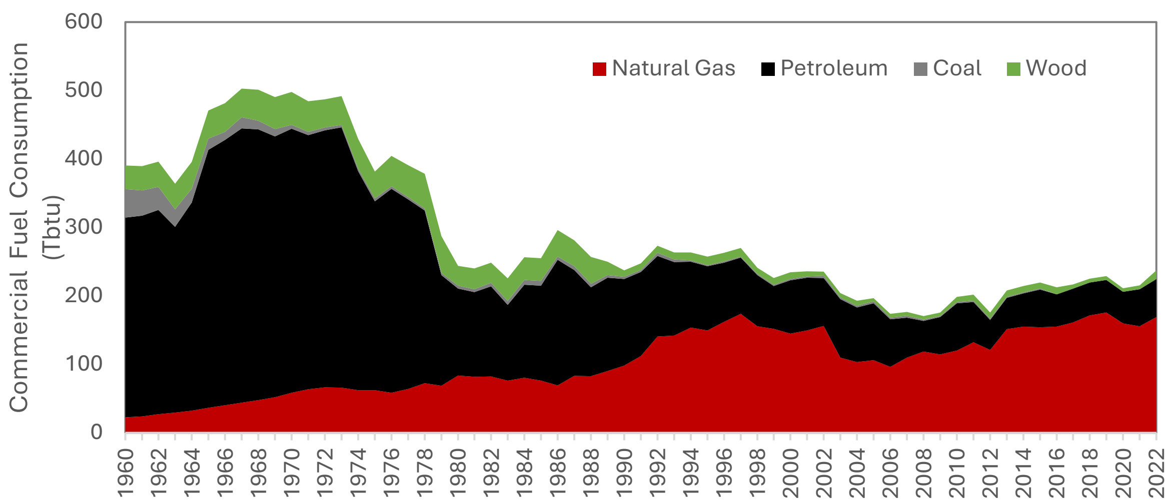

Figure 4. Massachusetts commercial sector energy consumption by energy source. Source: EIA State Profile[13]

By 2010, a consensus took hold that the growth of the gas system should be encouraged to take advantage of the low-cost gas supply unleashed by hydraulic fracturing and spur new connections that would eventually lower average costs and facilitate a shift away from more carbon-intensive heating fuels. Throughout the system's recent history, gas companies developed practices to encourage new customer connections by offering free or low-cost connections. These are described in the next section.

[12] U.S. EIA, *Massachusetts State Profile and Energy Estimates* https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_use/tx/use_tx_MA.html&sid=MA
[13] Ibid.

The Role of Line Extension Allowances in Supporting Growth

Line extension allowances are credits or discounts a utility provides to a new customer to cover all or part of the cost of extending service to that customer. Allowances are designed to encourage gas system growth by using anticipated future revenues from new customers to lower or eliminate the upfront cost that customers normally face.

Allowances have been central to the expansion of gas systems, historically and into the present, supporting growth through three primary project types: (1) new construction, (2) fuel switching in existing buildings, and (3) incremental load additions from current customers. These projects may involve adding new service lines to existing gas infrastructure or, in larger projects, installing new mains. For example, fuel switching could involve upgrading existing infrastructure for a single customer or expanding a main to new streets where future gas demand is anticipated. Incremental load additions refer to enhancing service for existing customers, such as adding new gas appliances.

The expansion of the gas system has historically been driven by evolving customer demand for gas, utilities' financial incentives to grow, and regulatory goals aimed at achieving broader public interest benefits. Gas has long attracted customers with its cost competitiveness, convenience, and reliable supply. As a result, legislators and regulators have historically incentivized access to gas, especially when competing technologies—such as coal and fuel oil—have proven to be less reliably supplied and worsen outdoor air quality.

Adding new customers to the gas system has traditionally enabled utilities to grow long-term revenue, but it also incurs immediate costs for the utility. These short-term costs stem from physically connecting the new customer to existing gas infrastructure, with such costs being clearly estimated and accounted for. However, the anticipated future revenues from a new customer are less certain as they depend on the customer's long-term gas usage and future gas rates.

Traditionally, utilities calculated that future revenues from new customers would justify the allowance, covering most or all connection costs. If future revenue projections suggest that the allowance would not cover the total cost of construction, utilities should require a customer contribution in aid of construction (CIAC) to cover the difference (Equation 1). The CIAC ensured that new customers would bear some of the costs, reducing the risk that existing customers or utility shareholders would subsidize new connections.

Equation 1. Balance of costs and revenues associated with line extensions

Cost of Expansion		=	***Line Extension Allowance***	+	***Customer Contribution*** *Excess portion or CIAC*
Services	Labor		Upfront capital investment justified by likely revenues.		Offset needed to ensure current ratepayers do not subsidize the construction cost.
Meters	Materials				
Mains	Transport				
O&M	Engineering				
Taxes	Overhead				
Insurance	Marketing				
Depreciation	Paving				
Return on Equity	Police				

The allowance functions like a loan from existing customers and investors, where the utility spreads the upfront costs over 10-20 years, expecting future revenues from the new customer to repay these costs. When projections assume future revenues will not fully cover connection costs, a CIAC is required to avoid having existing customers subsidize new connections.

Like a loan, the allowance calculation and the CIAC depend on various assumptions about future conditions. These include the customer's future consumption, the future operation and maintenance cost that the new customer incurs, other determinants of a utility's service cost such as depreciation and cost of capital, future taxes, and the selection of appropriate payback period and discount rate to reflect when the allowance is recovered from the customer.

Currently, the Department defers to the LDCs on what assumptions should go into determining the size of the allowance and the need for a CIAC only requiring:

> *"…that the obligation to serve a new, prospective gas customer is conditioned on (1) the gas company's having sufficient physical capacity to do so without reducing service to existing customers and (2) the prospective customer's paying the cost for installing suitable gas distribution facilities for service, so that existing customers do not subsidize the cost of the extension of service."*[14]

In its comments on the Department's investigation into the future of gas, the Office of the Attorney General observed that there is "no uniform model or costing matrix for determining the cost/benefit of line extensions or any indication that LDCs are considering the impact of the State's GHG reduction requirements in making their determinations."[15]

The potential for inconsistency in how allowances are determined is a concern because if an inconsistency is present, it would demonstrate a degree of arbitrariness, a potential range on how the standard is applied, and a range of cost implications for new and existing customers. While this might not have mattered for practical purposes in the past, more scrutiny is merited moving forward, given the risks facing the gas system today.

[14] Bos. Gas Co., D.P.U. 20-120, 2021 WL 4552393, at *68 (Mass. DPU Sept. 30, 2021).

[15] Tepper, R., et al. *Regulating Uncertainty: The Office of the Attorney General's Regulatory Recommendations to Guide the Commonwealth's Gas Transition to a Net Zero Future* (May 6, 2022). https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14922535

Line Extension Allowances in Massachusetts Today

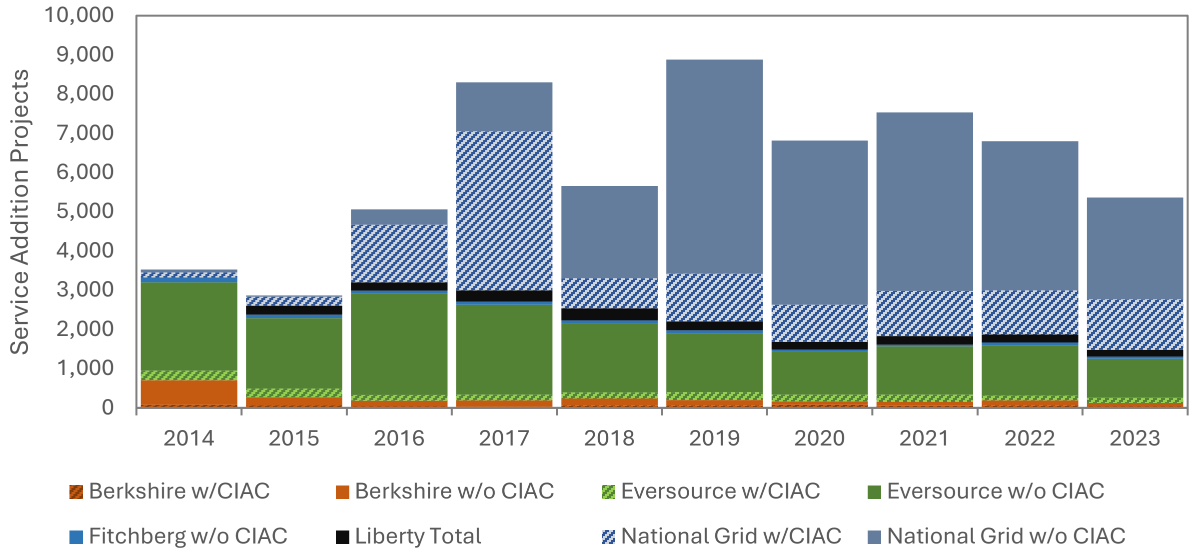

Figure 5. Service additions reported by each LDC in their responses. Excludes projects explicitly labeled as mains. Fitchburg did not report projects with CIAC nor distinguished mains from services. Liberty did not distinguish CIAC from non-CIAC projects. Services can serve multiple customers. Source: Author's visualization of Exhibits ES-2, BGC, CCAF-1, NG-7, Liberty-3

Line extension allowances have played a meaningful role in encouraging the growth of the gas system in recent years (Figure 5). Most new customers have received a no-cost extension over the past decade when a gas main is present and a service is required; however, three LDCs that reported service line extensions with and without a CIAC exhibited a range of no-cost connections: 63% for Berkshire, 79% for Eversource, and 89% for National Grid.

These differences are significant. These may represent different types of connections in different territories. We note that Berkshire has invested little in mains and that most connections are service connections, where National Grid and Eversource territory are likely to experience more developments and commercial and multi-family connections.

However, in our response to the Department's Question 1, we observed notable inconsistencies across the LDCs' approaches to estimating CIACs and allowances. For example, Berkshire's methodology included more customer costs than others and included operational and maintenance costs in its calculation of allowances and customer contributions, whereas Eversource does not. Eversource also uses a 34-year payback period, whereas Berkshire uses 20 years.

Berkshire implies using its calculator for all new service requests, whereas National Grid and Eversource practiced a default no-cost connection for service-only projects up until this year. These differences may explain why Berkshire has offered fewer no-cost connections in recent years despite the low cost of projects in Berkshire territory.

National Grid's allocation of CIACs over the last decade reflects inconsistency. From 2015 to 2017, CIACs were charged 19% of all connections. Starting in April 2018, National Grid "eliminated the CIAC for residential new connections for the first 100 feet of service only connections to align with the policies of the other LDCs."[16] This and National Grid's recent implementation of a minimum charge indicate that, for a time, existing customers may have been subsidizing many of these service-only connections. We highlight these numbers to emphasize that there is significant inconsistency in how the LDCs have been granting allowances in recent years. These inconsistencies will grow as new service arrangements with diverging demand and revenue potential become more common.

Line extension allowances have come under greater scrutiny across the country. Washington and Oregon have undertaken modest reforms of allowance practices in 2021 and 2022. This included shortening the payback period to 7 years (WA) and setting a maximum allowance (OR) for a gas utility. The California Public Utilities Commission (CPUC)[17] and Colorado legislature (2023)[18] eliminated allowances in 2022 and 2023, respectively. In early 2024, the New York Legislature came very close to eliminating line extension allowances and the state's explicit "100-foot" rule.[19] In all cases, the urgent need for climate-aligned regulatory policy and concerns surrounding cost recovery informed the decision to reform allowance policy or disallow allowances altogether.

The next section summarizes trends influencing gas demand in Massachusetts.

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[16] Exhibit NG-1 at 11

[17] California Public Utilities Commission. (2022). *Decision Eliminating Electric Line Extension Subsidies for Mixed-Fuel New Construction and Setting Reporting Requirements* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF

[18] Colorado General Assembly. (2023). *Senate Bill 23-29.1* https://www.leg.colorado.gov/bills/sb23-291

[19] New York Senate (2024). *Senate Bill S2016A. https://www.nysenate.gov/legislation/bills/2023/S2016/amendment/A*

CLIMATE POLICY AND ACTION ARE CHANGING THE LANDSCAPE FOR GAS DEMAND

Table 1 summarizes key major policies and trends shaping future gas demand in Massachusetts in new and existing buildings. These policies have begun to have a notable impact. Table 2 highlights a clear shift toward all-electric new construction under the 2022-2024 Mass Save program. By the first quarter of 2024, the construction of all-electric homes is on track to match the total from 2022, while the number of gas and propane homes has dropped significantly.

Table 1. Summary of policies influencing gas demand in the building sector.

Policy or Trend	Area of Influence	Description and Impact
Base Building Code Revisions	New construction and major renovations in 34 gas-served communities that have not adopted either the Stretch or Specialized Code	Updating to IECC 2021 from IECC 2018. Major change shifts from 80% to >95% annual efficiency minimum for furnaces.
Stretch Building Code Revisions	New construction and major renovations in 183 gas-served "Green Communities" that have not adopted the Specialized code	Additions to IECC 2021 are intended to significantly increase building energy performance.
Specialized Building Code	New construction and major renovations in 40 gas-served communities that have adopted the Specialized code	Designed to align with Mass statutory GHG emissions limits. Requires non-electric buildings to have a higher performance and be prewired for electrification
BERDO/BEUDO	Large buildings in Boston (>20,000 sf or 15 residential units) and Cambridge above (>25,000 sf).	Covered buildings are subject to a declining emissions standard.
Large Building Energy Disclosure	All buildings state-wide that are over 20,000 square feet.	Electric, gas and steam utilities are required to report energy usage data of large buildings they supply.[20]
Mass Save Pay-for-Savings	New construction that achieves a minimum threshold for savings.	Incentives are offered for energy savings even if fossil fuels are used.
Mass Save Existing Building Programs	Existing buildings undergoing energy efficiency upgrades.	Various programs and incentives are aimed at reducing gas use. Incentives for oil-to-gas conversions were phased out in the 2022-2024 Plan.
Federal IRA Tax Credits	Nearly all building energy projects.	Various programs and incentives are aimed at efficiency and electrification. Also includes incentives for high-efficiency gas equipment.
Clean Heat Standard (Draft)	Fuel emissions from the building sector.	The program is currently in development. Sets a minimum electrification target for covered entities.

Table 2. New homes by primary heat source as reported in Mass Save's 2024 Q1 KPIs.[21] Note this data does not include new construction that did not receive incentives.

	Homes (% of All Reported Homes)		
	2022	*2023*	*2024*
Electric	1,754 (20.9%)	4,077 (31.8%)	1,326 (63.8%)
Gas	5,258 (62.6%)	7,679 (60.0%)	563 (27.1%)
Oil	6 (0.1%)	0 (0.0%)	0 (0.0%)
Propane	1,384 (16.5%)	1,052 (8.2%)	191 (9.2%)

[20] Large Building Energy Disclosure | Mass.gov

[21] MA Energy Efficiency Advisory Council, *1st Quarter 2024 Program Administrators' Quarterly KPIs – KPI3* https://ma-eeac.org/wp-content/uploads/2024-Q1-KPI-EWG-Reporting-to-file-5.10.245150969.xlsx

Table 3. Existing homes receiving heat pump installs Mass Save's 2024 Q1 KPIs[22]

Fuel	Displacement Type	Households 2023	2023 Goal	% of Goal
Oil	Full	13,726	3,300	416%
	Partial	5,593	8,780	64%
Propane	Full	1,753	1,099	160%
	Partial	1,225	1,761	70%
Gas	Full	12,556	75	16741%
	Partial	10,502	264	3978%
Electric Resistance		8,744	3,336	262%
Total	Full Fuel Displacements	28,035	7,810	471%

The impact in the existing building sector has also been remarkable, as Mass Save has exceeded heat pump installation expectations (Table 3). In total, there were 28,035 new all-electric full fuel displacement projects in 2023, double the historical 2010-2021 increase in electric-heated households as observed by the U.S. Census American Community Survey (Figure 9) and equivalent to 1% of all Massachusetts households.

For new construction, even when gas is used, climate policy and available alternatives such as heat pumps are squeezing gas demand and increasing the likelihood that customers will further reduce or eliminate demand in the future, possibly before customers leave. The case for oil-to-gas conversions is becoming less compelling for existing buildings due to the increasing popularity of heat pumps and emerging policy mechanisms to reduce gas consumption. Buildings that switch to gas now may face future penalties or stranded assets as policies increasingly disincentivize gas use.

This is not hypothetical, as National Grid notes in its testimony:

> *"During the last 12-24 months, the Company is seeing a small but growing number of requests to install new gas services for limited use, supply backup or for a temporary period of time. For example, residential developers who are opting for electrification within their residential units are seeking gas supply for common areas and for backup and emergency generators. The Company has also received a similar request from an educational institution for backup service for residential dormitories and requests from large C&I customers who require a gas service for a limited number of years to allow for sufficient electric capacity to be built to fully electrify their buildings."*[23]

While National Grid appears to conduct a thorough load evaluation on new customers, the other LDCs do not demonstrate this in their testimony.

Actual use in such hybrid heating arrangements will likely deviate from forecasted use. Systems will be designed to operate differently, and users will adjust them to meet their preferences. Such hybrid arrangements make it increasingly difficult for LDCs to accurately predict future consumption and revenue and determine appropriate allowances or contributions per customer.

[22] Ibid.
[23] Exhibit NG-1 at 8

ARE PIPELINE ALLOWANCES STILL IN THE PUBLIC INTEREST?

In Order 20-80-B, the Department noted that it determines whether line extensions are reasonable using the "overarching consideration of the public interest, defined generally as requiring that there be no adverse impacts on existing natural gas customers."[24]

This definition referenced the Department's Order in D.P.U. 22-107, in which the Department approved service expansion into the Town of Douglas. In its approval, it noted that it previously used the 'no adverse impacts' to existing customers consideration to determine whether expansion would be in the public interest. In its order on the expansion, the Department also "considered whether the Company's petition would adversely affect existing customers and the Department's priorities An Act Creating A Next-Generation Roadmap For Massachusetts Climate Policy, St. 2021, c. 8, § 15, codified at G.L. c. 25, § 1A" ("Roadmap Act")[25] The Act states:

> *[T]he department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to [G.L. c. 21N]."*

The Department determined that the Douglas expansion was in its conventional understanding of the public interest as it would not adversely affect existing customers. However, the Department did not come to a finding on emissions, noting that "It is unclear that the Department's decision would have an impact on the GHG emissions goal" and described counterfactual scenarios in which the demand would move to another location as a rationale for its uncertainty. While the Department came to a neutral conclusion on the climate consideration, the Department did consider the project's claim of economic benefits to support other broader public interest goals as defined by the Roadmap Act.

The Douglas case fell under the Department's authority to authorize expansion into new service territories. Alternatively, the current inquiry into line extension allowances concerns the economics of offering new services. Here, the conventional public interest consideration of "Are existing customers adversely impacted?" centers around whether existing customers subsidize new customers. Answering this question relies on a common definition of adverse impact in the context of deep uncertainty surrounding the future of the gas system and the behavior of both new and existing customers. Given this uncertainty, the broader public interest considerations can be used to determine if allowances are in the public interest in the future.

The remainder of the document tries to answer these issues using two overarching theses that are aligned with the Department's review.

Our first thesis, considered in the next chapter in response to the Department's first question, is that the new paradigm of increasing cost, declining consumption, and the potential for early departures creates a situation where inconsistencies in allowance practices increase the risk that existing

[24] Ibid. at 100

[25] D.P.U. 22-107 Order at 4

customers subsidize new investments in the system while obviating the long-term benefits of adding customers to the system.

Our second thesis, considered in the subsequent chapter responding to the Department's second question, is that allowances are no longer in the public interest because they no longer align with the Department’s climate and affordability requirements. Greenhouse gas emissions and affordability considerations directed in state law are better aligned with a transition to non-combustible energy sources rather than the growth of the gas system. Under the framework established by the Department in the 20-80-B Order, gas utility allowances practices not aligned with the state’s climate requirements are no longer in the public interest.

The report then reviews other considerations, proposals for reforming extensions, and considerations for implementing allowance reforms before concluding.

With respect to public interest consideration of equity as defined by the Roadmap Law, limited data on who is receiving allowances make it difficult to analytically demonstrate that current practices are equitable or inequitable. Growth of the gas system has been driven in part by affluent single-family development. It is also true, however, that the Commonwealth’s commendable low-income energy affordability efforts have also expanded access to gas in recent years to the near-term benefit of low-income households previously served by oil. Opening access to utility data on what customers have been served by allowances in the past could be informative for understanding the efficacy of historical energy transition efforts across various social groups and communities. We hope that in similar future requests that the Department asks for and the LDCs provide information relevant to the equitable application of certain policies.

In the absence of such insight, all we can offer with respect to considerations surrounding equity and environmental justice is that:

(1) under current policy, the increasing costs of the gas system will be disproportionately burdened by those with less agency to leave the system (renters, low income households, and other historically marginalized communities that are likely to experience barriers to the energy transition);
(2) the negative consequences of climate change will be disproportionately experienced by historically marginalized populations.

These issues are addressed broadly in our response to Question 2.

Response to Question 1: The Cost of Line Extension Allowances

This section addresses the Department's first question for interested parties:

> *Do the LDCs' current models and policies accurately reflect the anticipated income and timeframe over which capital investments to serve new customers will be recovered? Provide an explanation and include supporting documentation.*

Our analysis indicates that while the LDCs' models and policies demonstrate the intent to ensure that existing customers do not subsidize existing customers, we cannot confirm that this standard is achieved in current practice; practices are inconsistent; and note that there is a significant risk that models and policies will not be able to meet this standard going forward. This inconsistency is not in the public interest.

To reach this conclusion, we first assessed the costs of adding customers reported in revenue decoupling adjustment factor (RDAF) filings. We find that the costs of new customers range from $3,000 at the lower end to over $10,000 for single-customer residential service connections. We find that the average capital investment is now $9,000 per new customer, totaling over $160 million to connect new customers to Massachusetts LDCs in 2023. We discuss the implications of this spending and highlight an effort by Eversource to manage the increasing costs for new customers. As shown in Figure 5, no-cost extensions constitute the vast majority of service connections in recent years. Since 2018, the number of free allowances has been 80% of all connections reported by the 3 LDCs (Berkshire, National Grid, and Eversource) that reported connections with and without a CIAC.

Second, we assess the LDCs' future revenues by reviewing their estimates for customer consumption in their allowance calculator and compare that to reported consumption for new customers in RDAF filings. We observe an inconsistency in default values in some allowance calculators provided by the LDCs and average new customer demand, with the latter being as much as 40% less than the default. While this may not reflect the calculators' actual application, no testimony or model sufficiently addresses the potential for future market and policy-driven declining consumption or early departures.

Third, we review utility allowance calculators and highlight notable differences in financial modeling methodology. We show how these can lead to significant deviations in results and possibly granting excess allowances where a customer contribution should be expected.

Fourth, we review the practice of no-cost connections granted based on screening criteria (e.g., a service-only connection within 100 feet of a main). Using the allowance calculators and scenarios for future demand, we show that such no-cost connections are increasingly likely to be subsidized by existing customers.

Fifth, we provide an illustrative analytical synthesis of the analysis.

Finally, we review two developments in Boston where service could not be granted to new construction that initially planned to use gas.

R1.1 Costs Associated With Adding New Customers

The cost of connecting a new customer to the gas system can vary due to various factors such as:

- Situational factors such as the presence of existing utilities and infrastructure (new construction faces fewer infrastructure conflicts compared to connecting an existing building to a main in an oil-to-gas conversion)
- Number of customers connected to a service
- Need for extension of a main and street work
- Number of customers to be served by a main extension
- Need for upgrades to other parts of the distribution system
- Customer acquisition costs
- Nature and inclusion of overhead

Generally, new construction will likely have lower costs; urban projects will have higher costs; multiple customer projects may experience economies of scale; and older distribution systems may face specific capacity challenges for adding new customers. An existing home may require trench work to lay a new service connecting the building with an existing main. Larger new multifamily developments may require detailed engineering analysis, new mains and other equipment installation, and a large service line to a meter bank that services 10's to 100's of units.

Prior filings (e.g., RDAFs) do not contain data to characterize such cost drivers. While some LDCs provided a breakdown of costs by rate class (or at least by residential versus commercial customers), Berkshire does not. Those that appear to use sector-specific allocators may not accurately reflect how new residential and commercial connections incur costs.

This section has two goals. First, it seeks to estimate an illustrative range of service connection costs for a prototypical single-family new construction or oil-to-gas conversion project where a main exists near a customer (e.g., <100'). This range will be used as an example to critique pipeline extension costs and practices later in this chapter. Second, it seeks to understand the trend in new customer investment over time from both aggregate and average perspectives.

The LDCs provided limited cost data in their responses. However, we use the data the utilities provided along with the LDCs' Revenue Decoupling Adjustment Factor (RDAF) filings to understand better the cost of adding new customers and how that cost has evolved in recent years. This approach has its limitations. Reporting practices differed widely by utility. Only Liberty reported the value of CIAC contributions over time. For other LDCs, notably Eversource, it was unclear if some "New Customer Costs" were associated with new customers or meter replacements. Our review also includes cost estimates from LDC GSEP plans and reconciliation filings because these filings typically include project-specific cost data on individual service replacement.

The review of each LDC's spending is provided in *Appendix 1: Review of New Customer Costs*, but is summarized in the next two sections, which reference figures and tables in the Appendix.

R1.1.1 Discerning an Estimate for a Prototypical Service-Only Residential Connection

We consider a prototypical single-customer connection as one that involves the connection of a new customer to an existing main with a new service (<100') and a new meter. The customer may be a new building, rebuild, or an existing building undergoing an oil-to-gas conversion. For simplicity, we assume that this will be a single-family residential customer, but our review emphasized that similarly situated small commercial customers would have similar costs. These projects would typically involve modest trenching and pipework. Historically, such a connection would have generally cost the customer nothing under the practice of the LDCs to offer such connections to encourage growth.

Berkshire reported the average cost of $0 CIAC connections as $2,937 in 2023.[26] We use this (~$3,000) as a lower-bound estimate for the cost of a new connection. However, given that construction costs in Western Massachusetts tend to be significantly lower than in Eastern Massachusetts and that Berkshire represents a fraction of new customers and investment, this value would likely underestimate the average prototypical connection. Further, on average, Berkshire's cost of new services in 2023 was $4,618. Berkshire reported that 91 connection projects in 2023 did not require a CIAC, whereas 35 did, with the average CIAC being $921.

National Grid provided connection-specific charge rates (Table 8) for tear-down rebuilds ($3,600) and relocations ($2,000 for <10'; $3,100 for 11-100ft; $4,500 for >100ft).[27] While these are flat rates, company policy states that customers are responsible for costs associated with such connections.[28] These situations are able to take advantage of existing infrastructure (meters, valves, and some of the service pipe) and may keep costs low relative to a new connection. Alternatively, the minimum cost of a new residential non-heating service is higher, at $4,200 and more closely reflects a large portion of the project cost.

Estimates for the other LDCs can be derived from a critical evaluation of their new customer spending and excluding main investments (2021-2023 averages). At the lower bound of this review is $3,000 in Eversource's NSTAR territory and $3,462 in Liberty territory (with an additional $1,023 average CIAC).

However, there is evidence of higher costs. The average service cost per customer was $7,449 in Unitil territory. National Grid's allowance calculator's output implied a cost of $6,997[29] for a new service (<100' without main work) in the Cape region of Colonial Gas territory – although it is unclear if calculator assumptions were appropriately set to the context we consider here. The cost of a meter was listed as $580 in all national grid residential cases.[30] The model further provides calculated CIAC costs using standard rates and demand levels and implies a CIAC need of $9,835 for this project in this region.[31] This appears to be the lower end of potential project costs in National Grid's territory; the model output implied much higher CIACs for other areas. A CIAC can exceed project costs to cover income taxes on the CIAC and offset O&M costs.

[26] Exhibit BGC at 7
[27] Exhibit NG-5 at 1
[28] Exhibit NG-2 at 20
[29] Exhibit NG-5 at 24
[30] Ibid. at 24
[31] Ibid. at 25

To fully evaluate the finances of new connections in the commercial space, project-level data on connection cost, demand projections, and building characteristics is needed, but unavailable. We do note that simple commercial connections are likely to exhibit similar costs to residential ones.

Our detailed review in the Appendix highlights that project costs can range higher, particularly for National Gird. The next section considers the total costs, including the main work and other capital spending.

R1.1.2 Total and Average Spending

To estimate total and average costs for adding new customers, cost and customer data were extracted from revenue decoupling adjustment filings (RDAF) back to 2017. RDAFs report capital spending associated with new customers. Total customer spending by LDC and by customer class is shown in Figure 6. We do not show a breakdown by asset type because National Grid, the largest spender, does not report investment by asset classes in the RDAFs.

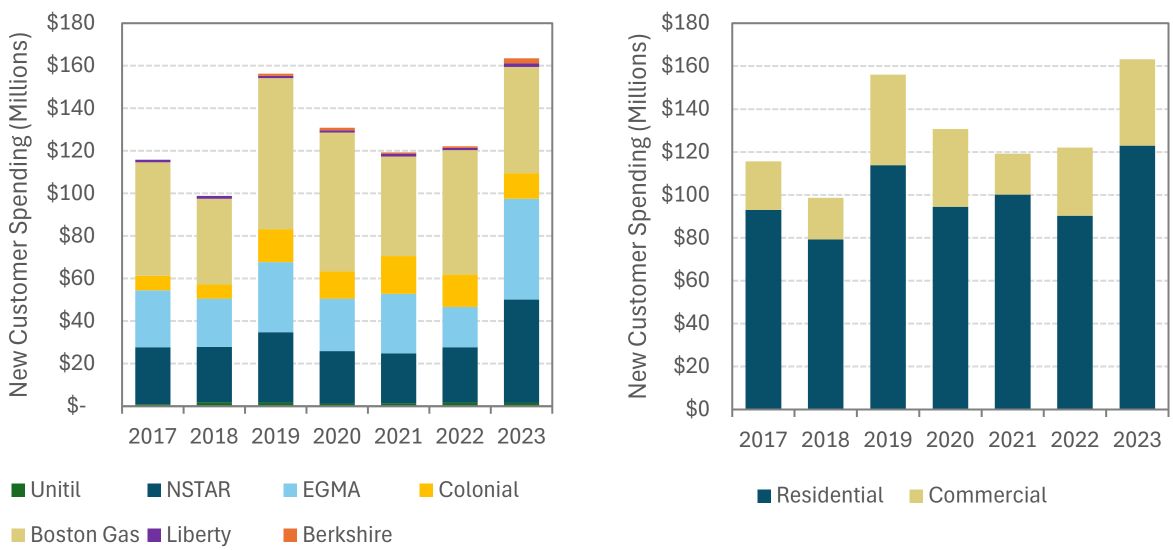

Figure 6. Combined new customer connection costs are reported in utility RDAF filings by utility (left panel) and sector (right panel). Values for Berkshire in 2017 and 2018 are not available, but they are minor.

During this time, customer growth has trended downward, with 2022 and 2023 exhibiting a net loss in commercial customers (Figure 7).[32] This rise in spending and a downward trend in customer numbers have led to a steady increase in per-customer spending that averaged $9,000 per new customer in 2022 and 2023, up 60% from the 2017-2020 average (Figure 8); the 2022-2023 average reflects a 50% increase from the 2020-2021 average. While it is difficult to provide a reasonable average estimate of commercial costs due recent declines in commercial customer counts, it is reasonable that that value

[32] While RDAFs do provide data on new customer additions, utility reporting cycles and viability in reporting make it challenging to construct a multi-year time series of customers. For our statewide estimates, we use aggregate EIA data, which is based on utility annual reports to the EIA (Form 176).

exceeds $10,000 per commercial customer statewide. Much of this is driven by National Grid and Eversource growth, which accounts for over 90% of spending and new customers.

Our 2019 and 2020 estimates for new customer addition costs align with those conducted in the 20-80 Pathway Report's Modeling Methodology Appendix (Figure 9) but also demonstrate a significant cost increase since that year. Some LDCs may include costs that might not apply to new customers (e.g., meter replacements for existing customers may be counted as new customer spending, as discussed in the appendix), which may cause both sets of estimates to be overestimated. However, our review finds that these estimates align with similar projects, such as GSEP service replacement.

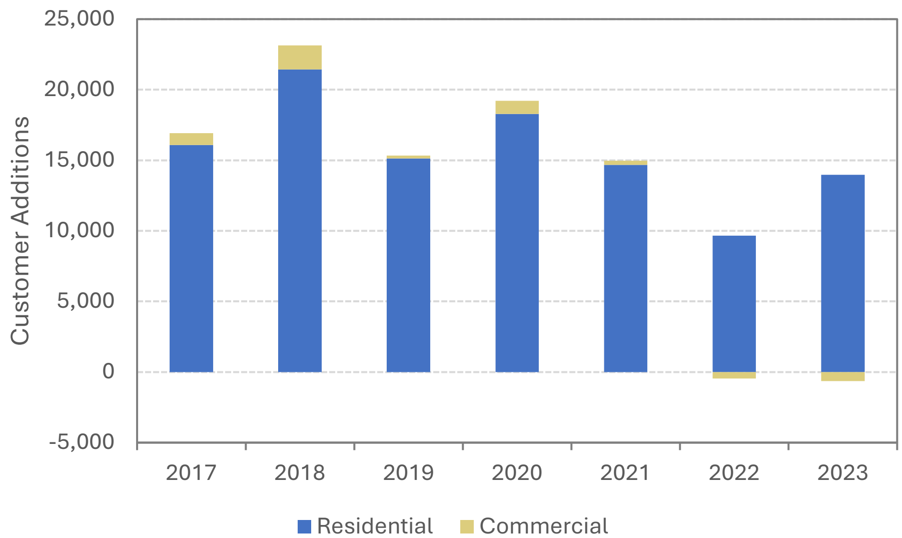

Figure 7. Customer additions by sector. Source: 2017-2022 were obtained from EIA Form 176; 2023 was obtained from the difference between the 2022 and 2023 annual return filings.

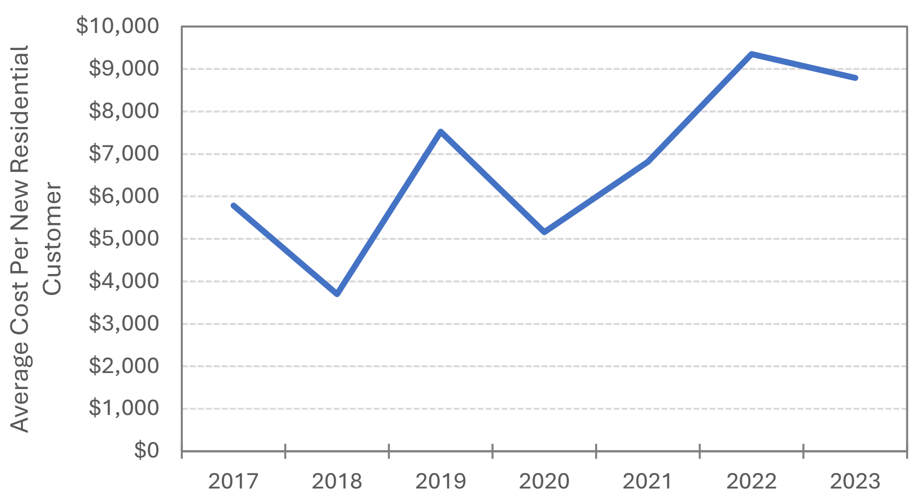

Figure 8. Average statewide new customer spending

Table 13. Assumptions on customer additions-related capital costs.

LDC	Customer Class	Capital Cost per Customer	Source
Berkshire	Residential	$2,286	2020 & 2021 Berkshire RDAF
	Non-Residential	$14,325	2020 & 2021 Berkshire RDAF
Eversource EGMA	Residential	$5,772	2020 & 2021 EGMA RDAF
	Non-Residential	$7,426	2020 & 2021 EGMA RDAF
Eversource NSTAR	Residential	$7,662	2020 & 2021 NSTAR RDAF
	Non-Residential	$13,543	2020 & 2021 NSTAR RDAF
Liberty	Residential	$3,488	2020 & 2021 Liberty RDAF
	Non-Residential	$7,213	2020 & 2021 Liberty RDAF
National Grid – Boston Gas (BGC)	Residential	$10,254	2020 & 2021 BGC RDAF
	Non-Residential	$23,578	2020 & 2021 BGC RDAF
National Grid – Colonial Gas (CGC)	Residential	$10,404	2020 & 2021 CGC RDAF
	Non-Residential	$10,517	2020 & 2021 CGC RDAF
Unitil – Fitchburg	Residential	$7,999	Weighted average of all LDC RDAF data
	Non-Residential	$13,616	Weighted average of all LDC RDAF data

Figure 9. Capital cost per customer addition from the 20-80 Pathway Report's Modeling Methodology Appendix (page 45).[33]

[33] Energy and Environmental Economics, Scott Madden Management Consultants. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report - Appendix 1. Modeling Framework and Assumptions* (March 2022) https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633271

R1.1.3 Implications of Spending

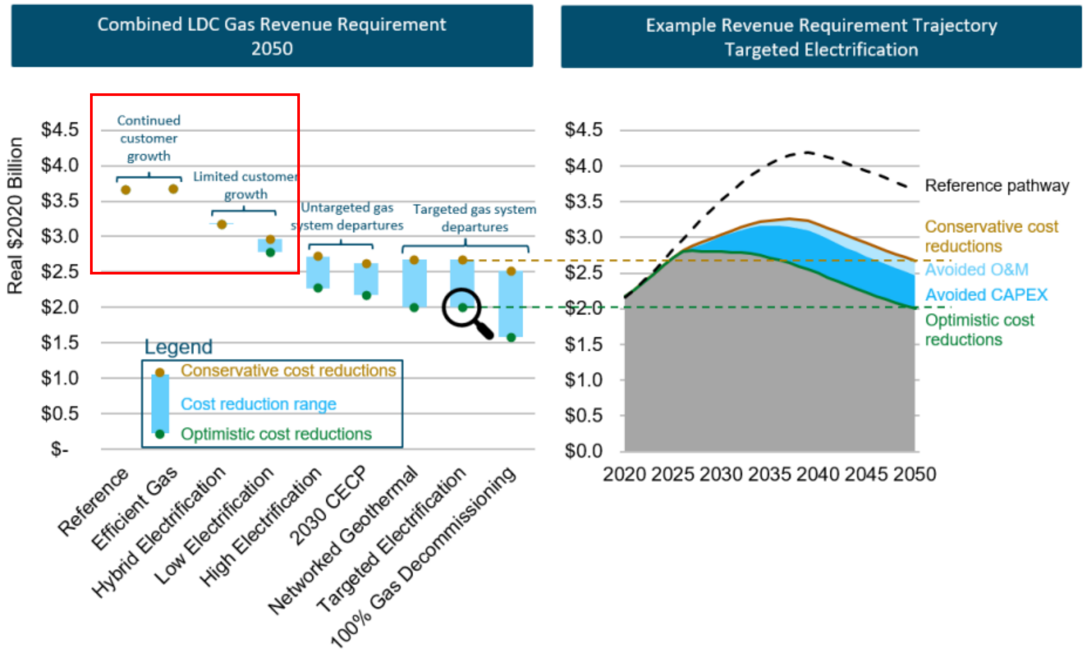

Figure 10. Source 20-80 Pathway Report Figure 29 (Page 70).[34] A red box was added to bring the reader's attention to the relevant area of focus.

Total spending on new customers in 2022 and 2023 was reported to be over $120M and over $160M, respectively. If this spending continues unabated, the implications will be considerable.

Figure 10 shows future revenue requirements under various scenarios modeled in the 20-80 Pathway Report. The left panel shows the 2050 combined LDC revenue requirement by evaluated scenario. The difference between the first pair and second pair of scenarios, ~$0.5B and ~$0.8B, reflects the impact of varying degrees of slowing customer growth. The avoidance of growth exhibited by these scenarios results in $1.57B to $2.32B in embedded system costs in 2050.[35]

Due to increasing electrification across the Commonwealth, these costs will be concentrated on a dwindling customer base. New customers who stay on gas will be exposed to higher rates or face emissions compliance costs that could be avoided. Additionally, existing or new customers who remain on the system will be likelier to have disproportionally low incomes. These issues are discussed in response to the Department's second question below.

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[34] Energy and Environmental Economics, Scott Madden Management Consultants. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Pathway Report--Technical Analysis of Decarbonization Pathways*. (March 2022). https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633269

[35] Ibid. Table 12 at 75.

R1.1.4 Allowances in Eversource's 2019 Rate Case

In its 2019 rate case, Eversource proposed a customer connection surcharge to spread the cost of a CIAC for new customers over 20 years. Eversource argued that the addition of customers helped to keep average costs low for existing customers; however, it noted that new customers are facing increasing costs of connecting to the gas system: "The primary cause of the cost increase is the limited availability and increasing cost of contractors to perform the necessary connections. With the up-scaling of GSEP and the significant infrastructure work ongoing with non-GSEP projects, the cost of connecting customers requesting gas service has increased to such an extent that it is unaffordable or otherwise uneconomic for customers to connect with the distribution system."[36]

Eversource noted that the cost of a CIAC needed to justify these projects posed "an insurmountable financial barrier"[37] for customers. The company noted that between 2015 and 2019, more than 2,300 "residential and C&I" customers requesting gas service chose not to pursue service due to the large CIAC payment required.[38] Eversource claimed that this would continue to reduce customer additions in future years.[39] Their proposal highlighted instances where the cost of a CIAC discouraged new gas connections (Table 4). These CIACs averaged $6,000 per customer.

Table 4. CIACs per new customers for proposed developments in Eversource territory that ultimately refused gas service. Source: D.P.U. #19-120, Exhibit ES-DPH/ANB-1, Table DBP/ANB-6 at Page159.

Town	CIAC Required	No. of Meters	Main Length (feet)	CIAC Cost per Home
Grafton	$242,000	48	2,000	$5,042
Westboro	$180,000	26	1,750	$6,923
Grafton	$205,000	25	1,500	$8,200
Uxbridge	$98,000	18	2,100	$5,444
Shrewsbury	$250,000	21	3,200	$11,905
Holden	$528,000	100	4,800	$5,280
Southboro	$240,000	20	2,300	$12,000
Hopkinton	$245,000	32	2,000	$7,656
Westboro	$25,000	22	1,100	$1,136
Plymouth	$256,000	66	8.600	$3,879

The surcharge would spread the CIAC over 20 years on top of the allowance payback through rates. Applicable customers would have the option of paying the surcharge or CIAC. Eversource noted that the surcharge would "distinguish those customers that are truly motivated by operational, economic, environmental or utilitarian purposes to use natural gas as their fuel source."[40] A 30% surcharge on delivery rates was approved for all customers except those in the high demand and high usage (G-53) rate, who would be levied a 10% surcharge.

Eversource proposed the surcharge to be applied to new service requests on or after November 2021 but subsequently chose not to implement the program "due to the Department initiation of D.P.U. 20-80 in October 2020 and the ongoing dialogue around the natural gas distribution network expansion."[41]

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[36] D.P.U. 19-120, Ex. ES-DPH/ANB-1 at 52
[37] Ibid. at 154
[38] Ibid. at 154, Figure DPH/ANB-2
[39] Ibid. at 154, Figure DPH/ANB-3
[40] Ibid. at 156
[41] Exhibit ES-1 at 17

R1.2 Revenue Projections

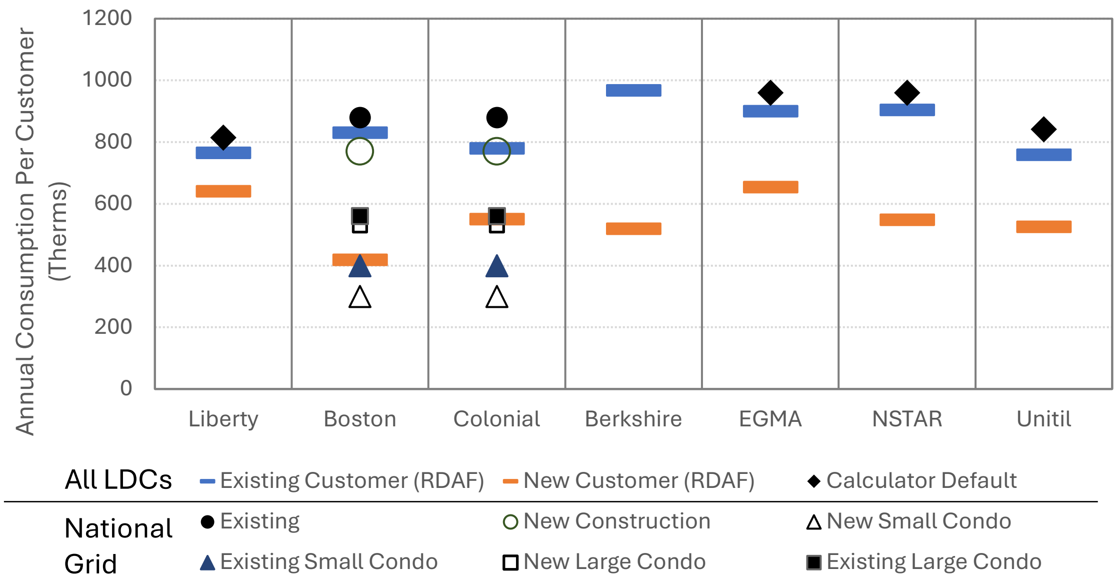

Figure 11. Bars: Reported average consumption per residential heating customer (standard rate except for EGMA & NSTAR) from 2024 Peak RDAF filings. Symbols represent new customer estimates provided by LDCs in their responses.

This section assesses whether LDC models and practices accurately assess future consumption and revenue. Figure 11 compares the average residential customer consumption for new and existing customers in each utility RDAF filing with the default values provided by several LDCs in their responses. New customer demand ranges from 20% (Liberty) to 50% (Boston Gas) less.[42]

For Boston Gas, many new customers are likely associated with multifamily developments or oil-to-gas conversions in smaller units associated with this denser territory. New multifamily developments will have lower demand due to higher energy performance; however, the average per-customer costs of these new connections may, but not necessarily, also be low.

Alternatively, an oil-to-gas conversion in a single unit on a three-decker may incur relatively high per-customer project costs but have low per-customer usage. Such a situation would typically qualify for the 100’ rule. Oil-to-gas conversions are typically associated with older housing stock that may have poorer energy performance on average. However, the concomitant application of building envelope measures and high-efficiency equipment associated with Mass Save-supported conversions can significantly reduce fuel demand. Although new single-family housing units perform more efficiently, recent trends in the size of single-family homes in the state may counteract efficiency gains in such cases.[43]

[42] Commercial consumption is highly variable given the larger range of use types and building sizes. In our review of RDAF filings and new customer consumption, we observed many cases across all rate classes where consumption by new commercial customers, on average, exceeded or was lower than that of existing customers.
[43] Miller, K. *Real estate: Homes in Massachusetts keep getting bigger. It's a problem.* The Boston Globe. (August 8, 2024) www.bostonglobe.com/2024/08/08/business/housing-mbta-communities-bathrooms-saga-partners/

National Grid's model was the only submission that attempted to classify future residential customer demand. It also submitted a comprehensive demand calculator that offers significant customizability and, if applied consistently, could demonstrate a robust evaluation of future demand and revenue. [44]

Eversource states, "Load assumptions will be based wherever possible on actual known data for the nature of the equipment being installed by the customer or developer. Where not known, the Company will use a level of use per customer based on the expected rate class."[45] Their policy further states, "revenue assumptions are currently derived from the 2009 sales data provided by the Rates group" but notes that they are reviewed periodically.

Liberty and Unitil's default consumption estimates for new customers were higher than those for typical existing customers. While their models can be customized, it is not clear how future consumption is estimated. Berkshire did not provide any default demand or methodology for estimating default demand.

The LDCs use current rates to estimate future revenues. Local distribution adjustment (LDAF) and revenue decoupling adjustment (RDAF) factors are excluded from these models as the former covers costs outside the expected revenue requirement for the LDAF and because the RDAF is intended to cover deviations from average consumption. We did not observe any use of rate escalators. Fitchburg explicitly stated: "Despite the potential of base rate increases being requested/granted during the project's life, the analyses will not include a rate relief assumption."[46]

All LDCs assume gas service will continue indefinitely and do not consider the risk of early customer departures. In communities covered by the specialized code, all gas buildings must be "pre-wired" for electric appliances. Many will experience a replacement-grade equipment failure within the 20-year line extension payback time horizon for residential customers.

Models could assume future rate relief, but such an assumption reflects an undesired outcome in which enticing customers to the gas system is not in the public interest of affordability. Increasing customer costs both obviates the value proposition of having access to low-cost gas today and incentivizes customers to leave, possibly before the end of the 20-year payback horizon.

We are unable to fully ascertain whether the LDCs accurately estimate future revenues. In National Grid's case, we observe a sufficient methodology for categorizing future demand based on certain customer features. This reflects an awareness and capability to adjust to future changes. We do not observe a similar capacity with the other utilities and note that Liberty's and Unitil's default assumptions underestimate the average consumption of new customers.

Determining whether estimated revenues are accurate requires a more detailed assessment of utility practices.

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[44] Exhibit NG-3
[45] Exhibit ES-3 at 4
[46] Exhibit CCAF-4 (CIAC Model.xlsm) at "Overview" sheet

R1.3 Review of CIAC & Allowance Calculators

Each LDC calculates customer CIACs using a bespoke discount cash flow model. Liberty, Berkshire, and Unitil each submitted functional discounted cash flow models. Eversource submitted a static PDF version of a single-spreadsheet model, and National Grid submitted a static PDF of a comprehensive multi-spreadsheet workbook. Table 5 summarizes key financial assumptions made by each LDC in their model.

This analysis of utility descriptions of policies, models, and practices cannot confirm how these are ultimately applied. All LDCs described their workflow to varying degrees in their testimony. All LDCs, except for Liberty, provided Service Terms and Conditions documentation. National Grid provided detailed internal process and policy documentation for service additions and adjustments.[47]

Generally, each LDC's methodology appears to reflect standard discounted cash flow practices for *estimating* the economic feasibility of a connection and determining necessary customer contributions. Some models (e.g., National Grid, Liberty, and Unitil) have more detail than others. Economic parameters and non-connection-specific inputs vary among the LDCs (property taxes, O&M, bad debt, depreciation schedules, etc.). However, differences in such assumptions are not as significant as connection cost and anticipated revenue.

Payback horizons differed among the LDCs. Berkshire and Unitil required a 10-year payback for commercial connections but 20 years for residential connections. National Grid and Liberty used 20 years for both, while Eversource's assessment uses a 34-year time horizon. Longer payback time horizons defer benefits for existing customers further into the future and increase the risk of unrecovered allowances. The models assume customers will remain on the system indefinitely and do not include decommissioning or net salvage costs. While decommissioning costs are not well characterized, they will require a meter shut-off and possibly a service shut-off.

Calculations of CIACs were typically performed using Excel's goal seek function to determine the level of customer contribution needed to make the connection viable based on each company's hurdle rate. Berkshire applied a standard factor to a project's NPV gap to calculate the CIAC, while Eversource's methodology was unclear.

Unitil's calculator included an option for calculating a monthly payment under a "Customer Contribution Payment Plan." The monthly payment is calculated by dividing the CIAC by the selected length of the payment plan (up to 36 months) and does not appear to charge interest. We could not determine if Unitil did offer payment plans.

We conducted a consistency test of the Liberty, Berkshire, and Unitil calculators to illustrate differences by harmonizing connection cost assumptions, rates, and the weighted average cost of capital (WACC). The results of this test are shown in Table 6. The consistency test was conducted in two harmonization steps. The first used consistent construction expenses, operation and maintenance, rate, and cost of capital, after which significant differences remained among the models. The second attempted to adjust more foundational factors and formulas in the calculators.

[47] Exhibit NG-5

Table 5. Comparison of methods for CIAC calculations. "RB" = Rate base

	Berkshire	Eversource	Unitil	Liberty	National Grid
Connection cost estimation	Provided average 2023 cost in testimony	None provided. Uses standard estimation factors that are reviewed annually.	None provided	Historical average costs can be determined from Ex. Liberty-3	Uses a unit pricing source estimator as shown Ex. NG-4
Method for determining expected revenues	None described. CIAC model takes user imports for summer and winter sales.	When available, known data is used. "Where not known, the Company will use a level of use per customer based on expected rate class."	Default demand values by rate calculated by 5-year historical analysis to estimate average usage by rate class.	Default demand values by rate class.	Determined by Ex. NG-3. Default demand values for residential. Commercial demand is customizable to connection.
Method for determining CIAC	Calculates needed contribution to bring NPV to zero plus tax adder	Upfront contribution to bring NPV to zero plus tax CIAC adder	Uses a goal seek macro on an NPV model to achieve hurdle rate. No CIAC tax adder.	Uses a goal seek macro on an NPV model to achieve hurdle rate. No CIAC tax adder.	Uses a goal seek macro on an NPV model to achieve hurdle rate. Includes CIAC tax adder.
Method demonstrated	Yes, Ex BCG-1 through BCG-4	Partially, static pdf of model provided, Ex. ES-3	Yes, in the provided calculator, Ex. CCAF-4 (CIAC Model)	Yes, in the provided calculator, Ex. Liberty-2	Partially, static pdf of model provided, Ex. NG-5
Connection Project Lifetime	Residential Heating – 20y Com. & Res. Non-heat – 10y	35y, assumed from the time horizon of the model	Residential – 20y Commercial and Industrial – 10y	20y for both residential and commercial	Default 20y, but the model allows different options
Costs Included in Cash Flow	O&M Property Tax (2.87% on initial capital cost) Income Tax	Property Tax (2% on RB) Depreciation Income Tax Return Requirement (WACC)	O&M (default 0) Property Tax (1.53% on RB) Insurance (0.02% on RB) Income Tax Return Requirement (WACC)	O&M Property Tax (2.53% on RB) Uncollectible (2.1% on O&M) Depreciation Income Tax Return Requirement (WACC)	O&M Property Tax (1.2875% on RB) Insurance (0.0275%) Uncollectible (1.7632%) Income Tax
Depreciation	20y for mains, services, meters	3% Depreciation Rate (~ 34y)	20.41y depreciation schedule determined by the weighting of assets for typical line extension accounts.	Services – 19y Mains – 38y Meter Installations – 22y Meters – 27y	Services – 32y Mains – 34y Meters – 28y
Tax Depreciation	MACRS 20	MACRS 20	MACRS 20	MACRS 15	Depends on project lifetime
O&M	Per therm values by rate class. (calculator references external utility OPEX model)	Typically, it is not included, but for main extensions of over 4 miles, O&M is estimated to be $1,300/mile of main annually.	None was provided, but documentation refers the user to obtain from a recent cost study.	Standard per customer ($40/y) and per ccf ($0.26) expenses as defined in D.P.U. 15-75	Average per bill rate used ($32.46) based on "Cost of Service in Compliance Filing"; $0.0258 insurance rate
Income Taxes	Federal - 21% State - 8% State Effective - 6.32% Composite - 27.32%	Federal - 35.0% State 6.5% Composite - 39.225%	Federal - 21% State - 8% Federal Effective - 19.32% Composite - 27.32%	Federal - 21% State - 8% State Effective - 6.32% Composite - 27.32%	Federal - 21% State - 8% State Effective - 6.32% Composite - 27.32%
Hurdle/Disc. Rate	7.20%	7.07%	6.77%	7.99%	9.48% - 12.48%
WACC	Pre-Tax - 7.20% After-Tax - 6.66%	Pre-tax - 11.64% After-Tax - 8.25%	Pre-Tax - 7.46% After-Tax - 6.77%	Pre-Tax - 7.99%	6.98%

Table 6. Results of the model consistency test. The assumptions used are intended to be representative but illustrative to demonstrate how model functionality can vary.

	Berkshire	Liberty	Unitil
Calculator-Exhibit	Ex. BGC-4 - Residential Heating Customer - 20-yr Model - Multiple New Load.xlsx	Ex. Liberty-2.xls	Ex. CCAF-4 (CIAC Model).xlsm
First Harmonization Assumptions			
Connection Cost	$5,000 service cost, $500 meter		
Monthly Customer Charge	$12.00		
Default Rates (per therm)	$0.700		
Pre-tax WACC	8%		
Financial Assumptions	Default values used as described below		
Default Inclusion of O&M	Yes	Yes	No
Default CIAC Tax Adder	Yes	No	No
Interest & Depreciation included in Cash Flow?	No	Yes	No
Default Depreciation	20-year, does not remove CIAC	20-year, net of CIAC	20-year, net of CIAC
First Harmonization CIACs	**Berkshire**	**Liberty**	**Unitil**
High Existing - 900 Therms	$1,383	$1,139	No CIAC
Low Existing - 750 Therms	$2,170	$1,662	No CIAC
Low New - 500 Therms	$3,482	$2,534	$1,289
Second Harmonization Assumptions			
O&M	$40 per customer/year + $0.255 per therm		
Property Tax	2%		
CIAC Tax Adder	Yes		
Depreciation	Net of CIAC – removes CIAC from initial book value.		
Other Adjustments	None	None	Add interest & depreciation to cash flow
Second Harmonization CIACs	**Berkshire**	**Liberty**	**Unitil**
High Existing - 900 Therms	$2,106	$2,111	$2,369
Low Existing - 750 Therms	$2,761	$2,884	$2,601
Low New - 500 Therms	$3,853	$4,174	$2,942

Our review observed significant inconsistencies across the three allowance calculators. Simply aligning rates, WACC, and connection costs resulted in a large range of potential CIAC across the three functional calculators (Table 6, First Harmonization).

One reason for this is the different treatments of operation and maintenance ("O&M") expenses across the models. This results in a range of values of $0 to $100's per year in cost for a typical customer—a lower O&M charge implies a greater allowance. Unitil's calculator requires a manual input of O&M and is defaulted to no value. Unitil's testimony notes that it includes insurance—a low-cost expense included in the model—but the testimony does not mention any other O&M expenses.[48] Liberty and Berkshire include estimates of O&M on a per-customer and usage basis based on their most recent rate cases. Eversource did not typically include O&M expenses in its calculation, arguing that new projects "will cause few incremental operating costs, and those costs would be difficult to quantify."[49] National Grid incorporates O&M. The calculators also allow users to include marketing or incentive costs in the analysis.

[48] Exhibit CCAF-1 at 10
[49] Exhibit ES-1 at 13

As shown in the second harmonization attempt (Table 6), it took considerable additional harmonization of underlying assumptions to converge on some level of consistency beyond O&M costs. One major driver of Berkshire's higher output compared to Liberty appears to be its inclusion of a tax adder or "gross-up" on the CIAC to account for the tax on the net income from the CIAC. National Grid[50] and Eversource[51] also claim to use a tax adder. It is unclear why Liberty and Unitil do not use an adder. However, they do not adjust for the CIAC in the book value, whereas Berkshire did. The exclusion of a tax adder for the CIAC by Liberty and Unitil may reflect an oversight that would also have the effect of underestimating the CIAC and overestimating the allowance. National Grid appears to include a tax adder for the CIAC.

Liberty includes depreciation and interest expenses in its cash flow, while Unitil explicitly states in its testimony that it treats "depreciation as a non-cash expense."[52] Unitil does not include interest but makes some adjustments relevant to interest expenses.[53] Treating these as cash expenses in Unitil's calculator brought its estimated CIACs more in line with Liberty's and Berkshire's. However, Berkshire's overall methodology is far less detailed than Unitil's and Liberty's; it does not include depreciation or interest in its cash flow, and its property tax cost is static across the evaluation period. In contrast, the other calculators reflect a decline in property tax cost as the assets depreciate. Eversource's cash flow calculation apparently includes a return requirement that includes depreciation and interest, but National Grid does not appear to include these in its cash flow calculation.

It is difficult to classify these disparate approaches as "correct" or "better" than another. Such forecasting models are intended to be used as estimators, and the differences may reflect situation-specific designs and judgment calls that one practitioner may reasonably address differently than another. For example, using a lower average O&M for new customers could be justified, as new customers typically add small incremental costs relative to the average. However, it is not zero, as additional customers incur metering and billing costs. Excluding it underestimates the CIAC and overestimates the allowance. We express additional concern about the inconsistent treatment depreciation and interest expenses across the calculators.

Still, the inconsistencies in calculator methodology and results are significant, and we note that in Table 6 , the inconsistencies in CIAC cost are larger at lower levels of demand and future revenue. As future gas demand and customer behavior change, such inconsistencies will increasingly conflict with the standard that existing customers should not subsidize new customers or that a more uniform method for determining allowances is needed to ensure that the standard is met.

If the Department were to establish a consistent approach to calculating allowances, it would need to establish a consistent discounted cash flow method and provide specifications on what elements should be included in cash flow, how to treat O&M, and guidance on how the CIAC should be calculated.

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[50] Exhibit NG-1 at 18: "the customer is also responsible for the income taxes associated with the CIAC"
[51] Exhibit ES-1 at 13: "The amount of the CIAC includes an adder to reimburse the Companies for income taxes each must pay on the CIAC."
[52] Exhibit CCAF-1 at 9
[53] Exhibit CCAF-4, Sch 2 at Cell D165

R1.4 Application of the "100-Foot Rule"

Assessment of connection financial viability can be resource-intensive for small connections. In these instances, it may make sense for a utility to provide a standard allowance or require a standard contribution based on screening criteria. It is often described as the "100-Foot Rule" and is typically applied to new connections within a certain (e.g., 100') distance from an existing gas main. This is based on the general assumption that such connections, on average, have sufficient revenues to justify their costs and do not necessitate a formal evaluation of each connection's specific cost – where the evaluation may add unnecessary costs. All LDCs (except Berkshire) have some version of this practice as reflected by their testimony (Table 7).

Table 7. Summary of LDCs' "100-foot rules".

LDC	Implementation of the "100-foot rule."
Berkshire	Response implies the allowance calculator model is used for all new connections. [54]
Unitil	"The company provides residential customers up to 100 feet of service pipe at no charge, under normal installation conditions. This policy was implemented for administrative efficiency and is grounded in the fact that the cost to install residential services less than 100 feet in length generally do not trigger a CIAC under the Company's IRR calculation"[55]
Eversource	"The Companies also no longer provide residential service line connections to the system at no direct cost for prospective customers converting from oil within 100 feet of a natural gas main."[56] Response implies that all new connections are added "consistent with CIAC policy."
Liberty	"If the new customer connection is a residential service for 125 feet or less, the Company does not utilize its CIAC model. However, in the case of long (> 125 feet) residential service lines, commercial or industrial service lines, and main extensions, the Company will always utilize its CIAC model to determine if a CIAC is needed."[57] The "majority of residential extensions have not required long (>125 feet) residential service lines. Therefore, most residential new services would not have required a CIAC."
National Grid	"Before April 2018, the Company charged residential CIACs for new service connections. In April 2018, the Company eliminated the CIAC for residential new connections for the first 100 feet of service-only connections to align with the policies of the other LDCs."[58] "[The Company] effective April 1, 2024, instituted a CIAC of $1,800 for all new residential heating service only connections, and a CIAC of $4,200 for all new residential non-heating service only connections... The Company plans to revise these figures again in 2025."[59]

National Grid's implementation of this has evolved. In 2016 and 2017, most connections required a CIAC. Starting in April 2018, National Grid eliminated CIACs for residential services to align with the "100-foot rule", but as of April 2024, it now charges a standard rate for residential service connections: $1,800 for residential heating and $4,200 for residential non-heating services up to

[54] Exhibit-BGC-1 Line Extension Testimony at line
[55] Exhibit CCAF-1 at 12
[56] Exhibit ES-1 at 17
[57] Exhibit Liberty-1 at 6 & 7.
[58] Exhibit NG-1 at 11
[59] Exhibit NG-1 at 12

4”. National Grid also established a minimum charge of $1,800 for commercial services up to 4” with higher minimum costs for the larger pipe. Commercial connections must also be evaluated by National Grid’s calculator and are charged the higher value of the calculator’s estimated CIAC and the minimum charge (Figure 5).

Eversource stated they “no longer provide direct-cost residential service line connections to the systems for prospective customers converting from oil within 100 feet of a natural gas main.”[60] However, Eversource’s website implies that no-cost services may still apply to customers and that “there may be a cost to install the gas service line. The cost will be provided by the energy advisor and will be included in the service agreement. If there is no cost for service installation, the customer will pay a refundable $1,000 deposit.”[61]

With rising connection costs and likely declining consumption from new customers, it is increasingly likely that new “100-foot” service-only connections should require a CIAC. Table 8 shows the results of various stress tests of submitted LDC CIAC Calculators using the best available low-end estimate for new service connection costs. We test several consumption scenarios: default calculator values, alternative available estimates, new construction aligned with each LDC’s new customer values, and two cases in which customers depart after ten years.

Table 8. 100’-rule stress tests of submitted functional LDC CIAC calculators for residential heating customers. National Grid and Eversource did not submit functional models. The “Alternative” value for Berkshire is their existing customer average (Figure 11), while Liberty’s value was provided in their CIAC calculator and appears to override the default value.

LDC	**Berkshire**		**Liberty**		**Unitil**	
Exhibit	Exhibit BGC-4 - Residential Heating Customer - 20-yr Model - Multiple New Load.xlsx		Exhibit Liberty-2.xls		Exh. CCAF-4 (CIAC Model).xlsm	
Connection Cost		$2,936.69 (Reported in testimony)		$3,155 (Example in calculator)		$7,499 (Appendix 1)
Monthly Customer Charge		$11.42		$11.80		$12.50
Default Rates (per therm)		$0.5991		Peak - $0.5553 Off-Peak - $0.3448		$1.6306
Scenarios	*therms/y*	*CIAC*	*therms/y*	*CIAC*	*therms/y*	*CIAC*
Calculator Default Existing Building			815	$749	845	None
Alternative LDC Value Existing Building	986	None	950	$478		
New Construction	519	$286	640	$1,099	525	None
Default Existing Building, 10y Departure	986	$134	815	$2,308	842	None
New Construction, 10y Departure	519	$1,543	640	$2,408	525	$1,435

Generally, the evaluation shows that future lower consumption and early customer departures would shift connection economics to require a CIAC payment. Unitil’s exceptionally high delivery rates mean that connection costs (even if high) can be recovered for all evaluated cases except a low-use new customer that electrifies fully after ten years (e.g., a building covered by the

[60] Exhibit ES-1 at 10

[61] https://www.eversource.com/content/residential/services/connect-to-gas (accessed 9/16/2024)

specialized code). We also note that, as shown above, Unitil’s calculators underestimate CIACs relative to Berkshire’s and Liberty’s.

A modern oil-to-gas conversion involving ducted cooling equipment could include a central heat pump instead of an AC unit. The incremental capital cost of this hybrid arrangement is low, and the potential for the customer to access favorable heat pump rates and avoid future gas use could provide financial savings that exceed the cost of the equipment upgrade. In this situation, gas consumption will be significantly lower than if gas was the sole heating source. Future revenues will be much lower, resulting in the new connection being subsidized by existing ratepayers. Presumably, the heat pump is subsidized by federal taxpayers through the Inflation Reduction Act and Massachusetts ratepayers under the Mass Save program.

Even the new National Grid minimum customer charge policy fails to account for this potential outcome. It recognizes that customers who use less (e.g., a non-heating customer) should contribute more than a heating customer. Still, the policy does not account for such hybrid heating arrangements—an arrangement the joint LDCs advocated for in their net zero enablement plans.

The rationale for standard no-cost or minimum charge allowances is predicated on uniformity in this customer class and the expectation that the practice does not result in existing customers subsidizing new customers. However, the customer class is becoming increasingly inconsistent as a growing number of new gas customers have the potential to have lower gas demand due to new technology and climate policy—additionally, the increasing cost of service-only connections further challenges allowance recovery.

R1.5 Analytical Synthesis

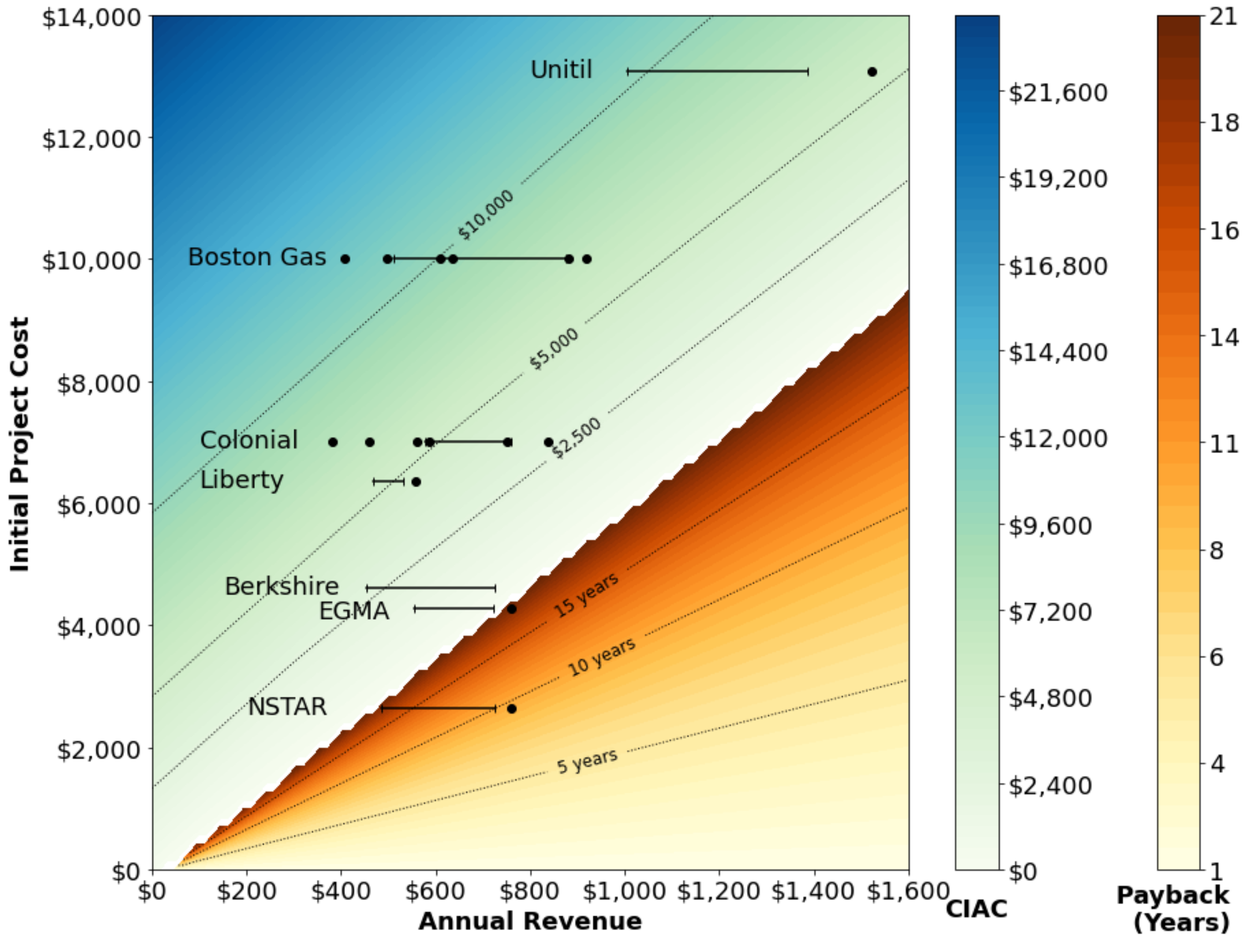

Figure 12. Calculation of payback periods and CIACs using a simplified DCF model. Bracketed lines and dots represent annual revenues based on each LDC's rates and the consumption shown in Figure 11The dots represent the markers of demand estimates provided by the LDCs in their responses, and the bracketed lines represent the range between new and existing customer demand extracted from RDAFs. NSTAR and EGMA are offset slightly. All revenue values are typical for a single-family home except for Colonial's and Boston Gas's lower values, representing condos.

We constructed a simplified discounted cash flow model to estimate payback periods and CIACs when the allowance is insufficient to generate payback (Figure 12). The simplistic model uses the same method as Berkshire's for calculating CIACs: a tax gross-up factor applied to any negative net present value if a payback is not achieved in twenty years. Project costs for each LDC are taken from the review in Appendix 1. The model provides values largely consistent with Exhibit Liberty-2, Exhibit BCG-3 (Berkshire), Exhibit BCG-1, and Exhibit NG-4 on page 25 (National Grid). Divergence from the Until calculator (Exhibit CCAF-4) is likely due to factors discussed in R1.3.

This figure shows that for a specific project cost, the potential allowance size, CIAC, or payback period can vary significantly based on the project cost and future revenues. It also shows that a range of project costs can have different implications for a similar class of customers.

R1.6 The Limits of Gas Expansion

Adding new customers may face constraints even in areas served by gas utilities. This has been most apparent through the issuance of moratoria on installing new gas installations in Wakefield and Pioneer Valley towns served by the Tennessee Gas Pipeline Northampton Lateral. Each of these areas has system capacity constraints.

West Roxbury multifamily development with propane heating.

Fenway multifamily development with oil heating.

Figure 13. Photographs of Boston buildings initially intended for gas service but amended to be supported by a tank fuel. Source: A. MLS Listing; B. Google Street View

Such constraints also emerge at local levels. A review of Boston's permit database identified instances where existing network capacity could not meet new demand. In one case, a 2019 infill project (4 units, ~2,000 sq ft per unit, in two buildings) in West Roxbury requested a permit (A1028318, A1028323) for the conversion of gas service to propane despite gas being available at the street (Figure 13, left panel). A visual inspection of the neighborhood using Google Street View observed that the street is served by plastic pipes interconnected to coated steel pipes typical of the 1960s vintage of the neighborhood.[62]

A 9-story, 34-unit infill 2016 development in Fenway filed a permit amendment noting: "Due to the lack of Gas available in the Street, conversion to Oil-fired equipment will be required. This permit changes the Mechanical and Heating equipment from Natural Gas to Oil." (A546149). The development (Figure 13, right panel) was on a street that historically had 4-story townhouse-style buildings. The street has experienced substantial redevelopment, yet a 6-inch cast iron pipe still services it.[63] A review of apartment listings indicated that the building still used gas to supply residents with cooking.

These examples show that constraints on gas system expansion can occur in suburban and dense urban locations and depend on the local conditions of the gas network. Substantial upgrades to the distribution system would be necessary to provide gas to these buildings. For example, the National Grid 2023 GSEP Filing includes estimates for projects in similar neighborhoods ranging from $3M-$6M per mile for Boston residential neighborhoods such as West Roxbury and $6.4M-$10.7M per mile for Fenway.[64] While GSEP would eventually facilitate upgrading these systems, such upgrades would have come after the targeted occupancy date of these buildings.

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[62] Running Brook Rd (link embedded, 6" CS marker observed on a neighboring street.)

[63] Burbank St - Google Maps (link embedded, 6"CI marker observed in front of neighboring building)

[64] 23-GSEP-04 Appendix NG-GPP-4

Response to Question 2: Climate and Affordability

This section addresses the Department's second question for interested parties:

> *Are LDCs' current practices inconsistent with state policies regarding GHG emission reductions by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions? Provide an explanation and include supporting documentation.*

We expand on this question to include the public interest consideration of affordability. For a time, gas service was the only affordable way to reduce emissions compared to oil. However, new approaches and related challenges facing the gas sector have created non-gas pathways for ensuring affordability while achieving alignment with emissions targets.

We conclude that creating incentives for gas system growth, especially if such incentives are at risk of being unrecoverable, is incompatible with state GHG targets. Further, while, in many circumstances, current rates favor heating with gas over electricity, long-run customer affordability is best preserved by electrifying heat and enacting policies that make electric heat more affordable, such as improved rate design. Gas system growth is thus inconsistent with the broader public interest considerations as defined by Massachusetts' climate law.

Despite this, our review of the LDCs' perspectives on aligning allowances with climate goals demonstrates that some LDCs persistently assume that gas system expansion is compatible with the state's legally binding emissions targets. We acknowledge that this view is likely based at least in part on efforts over the past 15 years to reduce heating emissions and that there is a long record of Department decisions before Order 20-80-B encouraging the growth of the gas system to displace more emissions-intensive oil and more expensive propane.

However, our review below demonstrates that expansion of the gas system is no longer compatible with the needed pace of emissions reductions—doubling from the past decade to this decade—and the ultimate need to eliminate emissions from the production of most heat generation rather than incrementally reduce emissions. With the maturation of the heat pump industry in Massachusetts, there are now practical ways to achieve greater emissions reductions compared to the limited incremental reductions achieved through oil-to-gas fuel switching.

Our review then explains how gas affordability assumptions also need updating in the context of pending stressors to the gas system. These stressors include increasing costs of maintaining gas infrastructure, climate policy, and unprecedented competition that collectively will concentrate on increasing costs and a dwindling customer base.

Our last section will revisit the issue of "decarbonized gas" as it was raised by National Grid in their testimony.

Our review does not seek to litigate the historical rationale for expanding the gas system. It is intended to assist the Department in developing a new record and standards that reflect current policy and conditions.

R2.1 Summary of LDC Comments on Climate Goals

Table 9 summarizes the responses from the LDCs regarding whether their current practices in allowing line extensions and acquiring new customers are consistent with state policies.

Unitil, National Grid, and Eversource provided position statements that imply that oil-to-gas conversions are aligned with state greenhouse gas reduction policies and that such conversions are an affordable measure for GHG reductions. This perspective is critiqued throughout the remainder of this chapter.

Eversource and Liberty reported that they had discontinued marketing for new gas service, following the DPU's order to disallow costs associated with marketing "geared to the promotion or expansion of gas service."[65] All of the LDCs note that they have begun efforts to educate customers about alternatives to gas, and three of the LDCs note that they require customers to sign an attestation that they have been made aware of such alternatives.

National Grid noted that they now require a minimum contribution for all new connections, and part of their rationale for the contribution was to better align their allowance practice with state climate goals.

Finally, some of the LDCs voluntarily described other activities that they consider to be consistent with the State's climate targets. These include their role as Mass Save energy efficiency program administrators, exploration of non-pipeline alternatives, and piloting geothermal networks. Several LDCs emphasized their efforts to reduce leak-prone pipes via the GSEP program.

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[65] D.P.U. Order 20-80B at 56

Table 9. Summary of LDC responses relevant to the Department's Question #2 on LDC efforts to align with State GHG limit.

LDC	Position on oil-to-gas conversions	Discontinued Marketing	Customer Education	Recent changes in line extension policies	Other Activities
Berkshire	"Specific to the line extension policy, the Company has implemented a process to educate and encourage new customers to consider electrification options prior to connecting new customers to the system." (Exhibit BCG at 9)	Not reported	Implemented a process to educate and encourage new customers to consider electrification options prior to gas connection	None since prior rate settlement (D.P.U. 22-20)	GSEP, energy efficiency,
Unitil	Oil-to-gas conversions "are supportive of and consistent with the Commonwealth's GHG emissions reduction policies in general and can contribute toward the state achieving its 2030 goals in particular." (Exhibit CCAF-1 at 15)	Yes	Provides information on alternatives to gas. Potential gas customers must sign an attestation that they've received information on alternatives to gas service.	None other than providing information about alternatives to gas.	Not described
Eversource	Notes emissions reductions associated with conversions. Implies that this supports emissions reductions where "economic constraints make an electric option less viable" (Exhibit ES-1at 18)	Yes	Provides information on alternatives to gas. Potential gas customers must sign an attestation that they've received information on alternatives to gas service.	"The Companies also no longer provide residential service line connections to the system at no direct cost for prospective customers converting from oil within 100 feet of a natural gas main." (Exhibit ES-1 at 10)	Efficiency, NPAs, electrification, networked geothermal. Climate Adaption and Mitigation Plan addressing company Scope 1 & 2 operation emissions.
Liberty	"The Company does not believe that it is incentivizing customers to extend its system through plant additions or even, for that matter, encouraging customers to choose natural gas service." (Exhibit CCAF-1 at 13)	Not reported	Implemented a process to educate and encourage new customers to consider electrification options prior to gas connection	No recent changes discussed.	Working to reduce leaks. Energy efficiency PA.
National Grid	"The Company also recognizes that near term feasibility and affordability criteria around electrification may also inform residential customer connection requests, many of which are oil to gas conversions that are aligned with progress toward the building sector emissions sublimit. (Exhibit NG-1 at 14 and 15)	Not reported	Provides information on alternatives to gas. Potential gas customers must sign an attestation that they've received information on alternatives to gas service.	As of 4/1/24, instituted a minimum charge of $1,800 for new resi. heating service, and $4,200 for new resi. non-heating service. Instituted a schedule of minimum charges for commercial ranging from $1,800 to $7,200 (NG-5 at 1)	Efficiency, GESP & leak reduction, NPAs

R2.2 Evolution of the Climate Consideration

The 2008 Global Warming Solutions Act ("GWSA") set near-term (2020) and long-term (2050) greenhouse gas emissions limits of 25% and 80% below 1990 levels, respectively. The State achieved compliance[66] with the 2020 limit largely through two key methods of action. The first was a large shift from older, inefficient coal- and oil-fired thermal electricity generators to gas-fired thermal electricity generators, responsible for the bulk of emissions reductions.

At the same time, the state halted growth in CO_2 emissions from the end-use combustion of fossil fuels through greater fuel-use efficiency. In the transportation sector, this was achieved through federal vehicle efficiency standards despite a marketed increase in vehicle miles traveled.

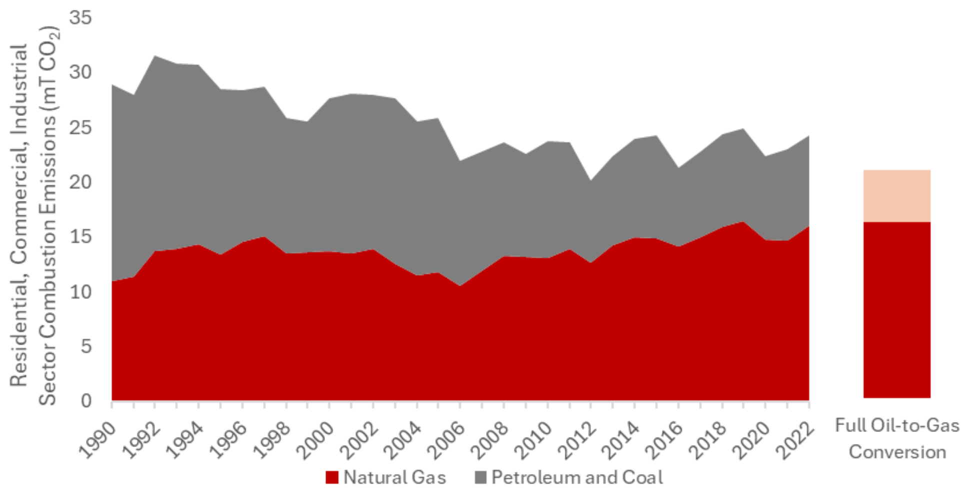

Figure 14. Historical greenhouse gas emissions from the Residential, Commercial, and Industrial combustion of fuels and illustration of emissions impact of full oil-to-gas conversion. Source: Mass GHG Inventory[67] and estimate of 80% to 95% efficiency improvement using standard EPA fuel carbon intensities[68] of 0.053 Mt CO2 for gas and 0.077 MtCO2 for oil.

In the building sector, both energy efficiency and oil-to-gas conversions drove a 15% decrease (Figure 14) in emissions despite substantial household growth, commercial floorspace, and economic activity. This reduction was supported by a regulatory environment deferentially supportive of gas system growth for new construction and fuel switching.

While the reduction from 1990-2010 is remarkable, emissions in the building sector have been flat since emissions from new, increasingly efficient gas construction were largely balanced out by ongoing oil-to-gas conversions and improving the efficiency of existing buildings. This is despite the passage of the 2008 GWSA.

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[66] Card, B. A. *Statement of Compliance with 2020 Greenhouse Gas Emissions Limit*. (2022). https://www.mass.gov/doc/statement-of-compliance-with-2020-greenhouse-gas-emissions-limit/download

[67] MassDEP Emissions Inventories Appendix C https://www.mass.gov/doc/appendix-c-massachusetts-annual-greenhouse-gas-emissions-inventory-1990-2021-with-partial-2022-2023-data/download

[68] U.S. EPA, GHG Emission Factors Hub. https://www.epa.gov/climateleadership/ghg-emission-factors-hub.

The inverter technology necessary to support cold climate heat pumps did not enter the U.S. market until 2013. At that point, early models were inefficient. With a lack of contractor familiarity, more market development would be needed—some of which was spurred on by efforts of the MassCEC—to mature heat pump installations to be ready to compete with gas. Until then, the growth of gas was the only strategy for reducing emissions. However, the ability of such a strategy has its limits, and through the adoption of the 2021 Act to Create a Next-Generation Roadmap for Massachusetts, the Commonwealth had adopted a more stringent 2050 target (85% gross emissions reduction) and interim 2030 and 2040 targets, which effectively doubled the pace of economy-wide emissions reductions and 2050 sector sub-limits which required specific action in the buildings sector.[69]

Figure 14's right panel shows a notional limit in which all oil heat was converted to gas despite many oil-heated buildings being outside the practical range of today's gas system. At 21 $MtCO_2e$, total emissions far exceed the GWSA's 2050 gross emission limit of 14 $MtCO_2e$ (80% of 1990 levels).

By 2021, however, cold-climate heat pumps emerged as the only scalable strategy for reducing emissions at the pace necessitated by the state's greenhouse gas emissions limits.

By 2024, high-performance, all-electric new construction reached effective cost parity with gas buildings for most building types.[70,71] This allows most new construction to stop adding to the state's emissions cost-effectively. All electric new construction also avoids future retrofit costs. Table 2 highlights the market shift in construction practices towards electric, driven by a combination of incentives and more stringent building codes.

Table 10. Potential GHG emissions reduction Source: Groundwork Data illustrative analysis using typical efficiency assumptions, today's grid carbon intensity factors, and approximate costs for a single-family home connection. Ignores the potential of energy efficiency and excludes the cost of gas extensions.

Strategy	Emissions Reduction	Approximate Cost
Maintain oil or simple modernization	0% - 10%	$5K - $10K
Oil-to-gas conversion	25% - 33%	$10K - $20K
ASHP meeting 50% heat demand with oil backup	33% - 50%	~$15K minus incentives
ASHP meeting 80% heat demand with oil backup	50% - 80%	~$20K minus incentives
Whole home ASHP	60% - 100%	$30-$35K minus incentives

Using heat pumps to displace oil has matured in existing buildings, making the oil-to-gas pathway obsolete (Table 3). Table 10 shows the impact of alternative strategies for reducing emissions from oil-heated homes. While partial electrification of oil-heated homes does not achieve the emissions reductions needed to align with long-term climate targets, it delivers greater emissions reductions

[69] Executive Office of Energy and Environmental Affairs. *Massachusetts Clean Energy and Climate Plan for 2050* (2022). https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050
[70] Walsh, Michael. *New Construction and the Future of Gas in Massachusetts.* Groundwork Data for Zero Carbon Massachusetts (February 2024)
[71] Built Environment Plus. "Zero Energy Buildings in Massachusetts: Saving Money from the Start." https://builtenvironmentplus.org/zero-energy-buildings/.

than oil-to-gas conversions, acclimates customers to heat pump technologies, provides customers with new cooling and comfort features, increases contractor experience with heat pump technologies, avoids large additional electric loads, and avoids new gas infrastructure.

For a period, the expansion of pipeline gas service was a tool for achieving incremental emissions reductions needed to achieve early climate goals. Given the emergence of practical and cost-effective alternatives, the continued indiscriminate expansion of pipeline gas now locks in emissions in situations where such emissions can be easily avoided.

The continued, albeit declining, provision of fuels may support the growth of renewables and heat pumps by providing firming and resilience capacity. These situations may be common as existing fuel equipment is phased out.

Achieving material GHG reductions from new connections will likely involve novel arrangements. This could involve a methane fuel cell supporting baseload demand in an area with constrained electric distribution infrastructure—CO_2 could be conceivably captured from such equipment. Alternatively, a new combined heat and power system that provides firming support to heat pumps and electricity supply could lower system costs. Upon evaluating such cases, the Department may find that granting allowances may support GHG reduction goals while being a prudent investment.

This nuanced perspective is backed up by the Commonwealth's substantial energy transition research and the 20-80 Pathways Report. These studies emphasized the importance of avoiding the growth of the gas system to take advantage of the lowest-cost electrification opportunity and avoid further investment in the gas system. The 2025/2030 Clean Energy and Climate Plan and the 20-80 Pathways Report highlighted cost savings benefits associated with dual fuel strategies if those strategies could be used to avoid investment in electric and gas infrastructure.[72] Notably, the 20-80 Pathway Report evaluation of the hybrid dual-fuel heating pathway also included the hybridization of oil-heated homes, contributing approximately a third of the avoided electric system cost associated with that scenario relative to others.[73]

Still, despite opportunities for integrated approaches, this body of research demonstrated the need to transition to accelerate emissions-eliminating ***systems*** strategies.

What about methane emissions?

New services and mains are far less leak-prone than cast iron or unprotected steel pipes; however, they still leak. Using the state's methane emissions factors, PHMSA inventories, and EIA customer counts, we estimate that the 2014-2022 expansion resulted in 360 tonnes of additional annual methane emissions (10,206 tCO2e using GWP_{100} of 28).

[72] Massachusetts Clean Energy and Climate Plan for 2025 and 2030. https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.
[73] Walsh, MJ, *Assessment of Proposed Hybrid Heating Strategies: Working Paper submitted as a Comment* in 20-80, Starting at p27. May 6, 2022.
https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14917659

R2.3 Evolution of the Affordability Consideration

Beyond the potential for incremental emissions reductions, expansion of the gas system was viewed as worthwhile because gas was perceived as the most cost-effective or affordable heating source. Growth has the potential to reduce average customer costs—so long as the present value of the cost of adding customers is less than the present value of the revenues from new customers to the utility. The availability of low-cost gas in recent years further created a clear public interest in expanding the gas system to provide access to lower-cost energy.

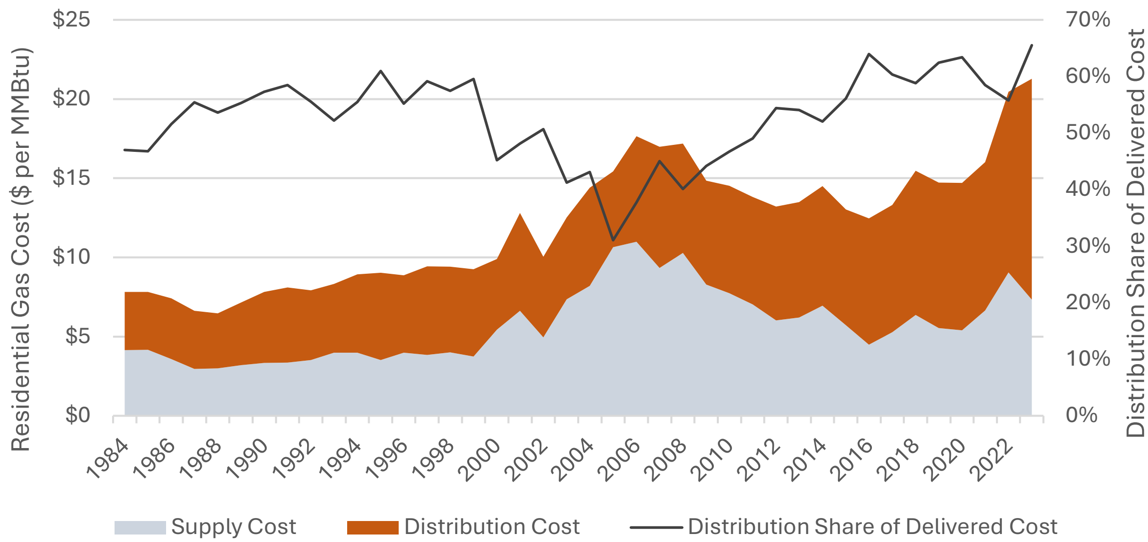

Figure 15. Residential gas costs are broken into supply and distribution components. Source: U.S. Energy Information

Today, gas supply cost is remarkably low (~$2-$3 per MMBtu) due to the emergence of hydraulic fracturing technology, which opened access to America's expansive shale gas resources in the 2010s. Given estimates of economic reserves and market forecasts, gas supply costs can reasonably be expected to remain low for the foreseeable future. However, it does cost more to supply New England with gas (~$4-$7 per MMBtu on average) due to limited pipeline capacity.

Historically, the costs of distributing gas have been roughly equivalent to gas supply costs, but delivery costs have steadily risen relative to supply costs in recent years. Initially, this was due to supply costs staying flat; however, in 2023, the share of distribution costs reached its highest share in the past 40 years when average delivery costs reached $14 per MMBtu or two-thirds of customer costs (Figure 15).

Gas affordability is being challenged in three ways, as depicted in Figure 16. First, increasing infrastructure costs, largely driven by modernizing the state's leak-prone cast iron pipe, are expected to require over $15 billion in capital investment through 2039. [74] When factoring in continued customer growth, it is anticipated that the combined LDC revenue requirement will rise from just over $2B today to over $4B in the late 2030s (Figure 10).

[74] 20-80 Pathways Report, Appendix 4

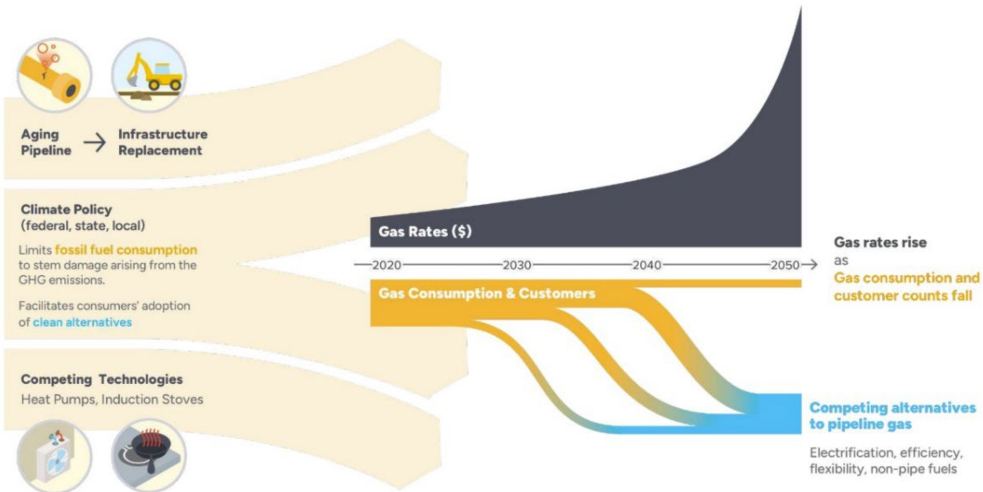

Figure 16 . Key drivers of increasing gas costs. Source: Groundwork Data Illustration

Second, growing climate policy puts downward pressure on gas consumption. Such policy can include mechanisms such as emissions standards that place an implied price on emissions.[75] Alternatively incentives and rate design lower the relative cost of electrification. Compliance using renewable natural gas faces significant challenges to implementation at scale but would incur a $20 to over $30 per MMBtu premium.[76] This would more than double current gas costs.

Third, continued reliance on gas forgoes consumer benefits associated with electrification. Electrification and the application of complementary building HVAC improvements offer an opportunity to improve building comfort and health by adding cooling, reducing drafts, improving air quality, and enabling zoning. Induction cooktops offer improved cooking experience and functionality through fine temperature control. Electric fireplaces offer increased customizable ambiance. New technologies need not be cheaper than gas to deliver consumer benefits.

While several LDCs argued in their testimony that oil-to-gas conversions are the most affordable of these strategies, it is important to emphasize their affordability assumption is solely due to the basic needs of a furnace-for-furnace or boiler-for-boiler system replacement. Modernizing old systems can involve the conversion of steam to hot water or adding ducts to support cooling and ventilation. Such modernization can deliver comfort improvements that are included to varying degrees with typical electrification projects. Most households desire such improvements, and delivering these improvements to low-income households is socially desirable due to the health and productivity benefits they provide.

The combination of these factors will drive up costs and obviate efforts to make gas more affordable. Gas has been the most affordable energy source for Massachusetts consumers for two decades. That period is ending, and so is the rationale for growing the gas system.

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[75] Boston's BERDO includes an alternative compliance payment of $216, while DEP's Nov. 2023 Draft Clean Heat Standard proposed an alternative compliance payment of $190.

[76] *Potential of Renewable Natural Gas in New York State*. NYSERDA (2022). https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/EDPPP/Energy-Prices/Energy-Statistics/RNGPotentialStudyforCAC10421.pdf

R2.4 The Misdirection of a "Decarbonized Gas Network"

Some entities, including the LDCs, have argued that the growth of the gas network is consistent with climate goals because the gas network could be decarbonized in the future using alternative gases such as renewable natural gas, synthetic natural gas, or hydrogen. In its testimony, National Grid states, "The Department has recognized that access to the gas distribution system will be needed for customers for whom it is not feasible to electrify, such as commercial and industrial customers that require natural gas for processes heat applications. Access to an increasingly decarbonized gas network would enable new connections to the system while progressing the Commonwealth's GHG reduction goals."[77] Such a perspective represents a misunderstanding of the role and limitations of renewable fuels in the transition to a net zero future.

Our current understanding of the future role of combustible fuels in the energy transition is that their consumption needs to decline rapidly but that they still can play a specific, targeted role in lowering the cost and barriers to achieving the Commonwealth's statutory targets. In this role, they are a transitional and presumably long-term firming resource to support grid reliability and local resilience, and in situations where electrification faces specific challenges to meeting a limited set of essential customer demands and peak heating needs. Whether such fuels are delivered via truck or pipeline is a matter of situational context. New low-fuel demand situations are likely to be more cost-effectively met by a tank rather than new gas infrastructure if new infrastructure is needed.

Fuel decarbonization is a separate matter. The Massachusetts 2050 Decarbonization Roadmap Energy Pathways' analysis was designed to test the implications of continued reliance on pipeline fuels against efforts to reduce reliance on pipeline fuels. Its findings were that continued reliance on pipeline fuels increases the risks of missed climate targets and increases costs due to the high costs of "decarbonized gas." The contributors to the 2050 Roadmap also emphasized this in follow-up reports.[78,79] The rationale is that the cost of alternative gases is excessive relative to the cost of fossil gas and that it would be more cost-effective to allow fossil gas use up to the point where it could no longer be balanced with removals under the state's net zero framework, which requires 85% emissions cuts.

The 20-80 Pathway Report did not attempt to refute this finding and aligned with the consensus that large reductions in gas demand were needed to achieve the emissions goal—largely because of the high cost of "decarbonized gases."[80] The easiest and most cost-effective places to achieve that goal—as emphasized in the Roadmap—are in the places that rely on delivered fuels such as oil

[77] Exhibit NG-1 at 14

[78] Walsh, M. & Krones, J. *Limited and Careful Use: The Role of Bioenergy in New England's Clean Energy Future.* https://www.clf.org/publication/limited-and-careful-use-the-role-of-bioenergy-in-new-englands-clean-energy-future/ CLF (2023).

[79] Kwok, G. & Haley, B. *Low Carbon Fuels in Net-Zero Energy Systems*. https://www.evolved.energy/post/low-carbon-fuels-in-net-zero-energy-systems (2022).

[80] The 20-80 Pathway report exogenously assumed that "decarbonized gas" would be available and directly substitute for fossil methane, on pace with emissions caps. This contrasts with the methodology of the Roadmap's Pathways Analysis, which allowed "decarbonized gas" and emissions allowances to compete in a simulated market, thus more accurately reflecting the least-cost outcome under an emissions cap.

and propane instead of the gas system, particularly in the case of new construction where electrification is mature, practical, and cost-effective.

Further, the gas system does not have a monopoly on the use renewable fuels. If one assumes the availability of "decarbonized gas," one must also assume the availability analogous substitutes for oil or propane fuels. These could also be used to decarbonize auxiliary or backup services in new or existing buildings. In the case of existing buildings with oil or propane equipment, they could take advantage of existing assets, perhaps with some modifications.

Since the publication of the Roadmap and subsequent 2025/2030 and 2050 Clean Energy and Climate Plans,[81,82] the industry has been on notice that the continued growth of the gas system is not consistent with state climate law. Further, even if decarbonized gases were to play a role, the limited availability of decarbonized gases necessitates a smaller gas system with limited consumption compared to today, and any potential should not be used to justify a general expansion of the gas system.

[81] Executive Office of Energy and Environmental Affairs. *Massachusetts Clean Energy and Climate Plan for 2025/2030* (2021) https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030
[82] Executive Office of Energy and Environmental Affairs. *Massachusetts Clean Energy and Climate Plan for 2050* (2022). https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

Response to Question 3: Other Considerations

In its third question to interested parties, the Department asked:

> *Are there other issues that the Department should consider in developing a common framework for new service connections?*

We review other considerations not explicitly discussed in the previous chapters.

R3.1 Some Expansion May Conflict With Targeted Electrification

In its 20-80 Order, the Department recognized (1) the need to implement non-pipeline alternatives such as targeted neighborhood-scale electrification to avoid costs associated with reinvestment and (2) the need for comprehensive GSEP reform to control costs. New customers in gas-served neighborhoods that could be suitable for gas pipeline extension pose a concern. If the neighborhood were to undergo targeted electrification, an oil-to-gas-to-electric conversion would result in additional customers needing to be involved in the electrification and one that has recently undergone a significant upgrade.

R3.2 Industry Perspective: Economics & Ratepayer Fairness

In July 2024, the American Gas Association (AGA) released a commissioned report: *The Current State of Natural Gas Line Extension Policies*.[83] The report raised two central concerns related to the decreased use or elimination of allowances.

The first concern is the industry perspective that line extension policies encourage the growth of a system that serves the public interest by promoting economic growth and reducing greenhouse gas emissions in comparison to oil. We critiqued this perspective exhaustively in our response to the Department's second question but emphasize here that the AGA's perspective does not reflect the well-established incompatibility of gas use at current scales with climate goals.

The second concern is that requiring new customers to pay for the incremental cost of their connection while charging them standard distribution tariffs results in them subsidizing existing customers. In a growing system, this argument has merit.

The implications for a system in decline are more nuanced. A new high-revenue customer, with a 10-year payback, that has a low connection cost to a sustaining portion of the gas system may contribute cost relief to a system transforming as average rates rise. Contrast this with an oil-to-gas conversion in a low-demanding condominium with a 20-year payback window and is on a street that could be decommissioned in 10 years. Ultimately, the question of who is subsidizing who, requires a more detailed assessment and a consistently applied standard for defining when a subsidy occurs. Both of which do not exist under the current practices in Massachusetts.

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[83] McDermott, K. & Peterson, C. *The Current State of Natural Gas Utility Line Extension Policies*. American Gas Association, (2024), https://www.aga.org/wp-content/uploads/2024/07/The-Current-State-of-Natural-Gas-Utility-Line-Extension-Policies_FINAL.pdf .

R3.3 Workforce Transition Concerns

Potential changes to line extension policies, along with other policies, may have the effect of reducing gas workforce needs. However, at a time when unemployment is at historic lows and demand for skilled workers is high, such workforce impacts are likely to be manageable.

The LDCs have noted in their GSEP filings that they face considerable workforce recruitment and retention challenges regarding the pipelaying workforce needed to construct new mains and lay service connections.[84] With respect to pipefitting, it is understood that the building trades are facing similar workforce challenges.

Even with a full curtailment of line extension allowances, it is unlikely that connections will stop overnight. For the next several years, connections will still move forward based on customer preference. Further, age-out and efforts to transition the workforce to similar high-needs jobs will naturally align with reduced growth.

Some workforce representatives have argued in various forums that continued investment in the gas system is justified due to the potential of alternative fuels. We address this topic in R2.4. Maintaining the perception that gas growth can continue based on the presumption of a decarbonized gas network is ultimately disadvantageous to labor and industry as it distracts from urgent and necessary transition planning.

The Department has authorized network geothermal pilot projects.[85] Further, the Department has approved electric sector modernization plans that include expanded undergrounding of electric distribution infrastructure to support system hardening.[86] Both strategies can leverage many of the skillsets involved in gas pipe replacements while clearly aligning with the Commonwealth's climate mitigation and resiliency efforts, but we acknowledge there may be a need for transitional support.

R3.4 Impact on Housing and Customer Energy Costs

The rising costs of housing is an urgent public interest issue in Massachusetts.

In our report on *The Future of Gas in New Construction in Massachusetts,*[87] we observe that construction of all-electric new construction has reached cost-parity with gas construction. While certain non-energy source-related HVAC design decisions can influence the final cost of the project, we noted that the use of ductless mini splits avoids costs associated with internal gas piping and ductwork while providing zoned heating and cooling. Further, this report notes that electric heating strategies are likely more cost-effective when costs associated with the pipe extension are incorporated into the analysis.

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[84] D.P.U. 23-GSEP-05, 23-GSEP-06

[85] See D.P.U. 24-11 (National Grid) and D.P.U. 24-10 (Eversource) and D.P.U. 24-12 (Unitil)

[86] See D.P.U. 21-24 (National Grid) and D.P.U. 21-54 (Eversource)

[87] Walsh, M. J. *The Future of Gas in New Construction in Massachusetts*. ZeroCarbonMA. (March 2024) https://www.groundworkdata.org/s/New-Construction-and-the-Future-of-Gas-in-MA-2724.pdf

Notably, a 2023 study by the MIT Center for Real Estate and Wentworth Institute of Technology on changes to the state's building cost found that under proposed changes to the state's Stretch Energy Building Code, all-electric new construction was cheaper than dual-fuel construction.[88]

Our prior report also observes that new construction has exceptionally high energy performance, resulting in relatively low energy bills regardless of whether the building is served by electric or gas based on today's rates. This means that low-income households who occupy new units start with a low energy burden. If the discrepancy between gas and electricity is still a concern, improved rate design can obviate those concerns. On June 28, 2024, the Department approved a seasonal heat pump rate proposed by Unitil that makes heat pump usage more affordable.[89] On September 30, 2024, the Department rejected a different plan by National Grid for a blanket technology-neutral 10% discount for high-usage customers, proposing low-income and heat-pump-friendly rates.[90] The Department instead instructed National Grid to develop a rate structure similar to Unitil's. The Commonwealth's Interagency Rates Working Group is evaluating similar strategies to inform a state-wide approach to rate reform.[91] Ultimately, disincentivizing gas connections reduces the risk that customers will be exposed to projected higher gas rates in the future.

Mass Save data presented in Table 2 show that construction of electric homes in Q1 2024 exceeded the pace of construction of all buildings in 2022. In areas such as the Pioneer Valley and Wakefield, moratoria on new connections have not hindered the development of large housing complexes.

Ultimately, the impact on housing costs from any adjustment to line extension allowances is small relative to the cost of construction and the impact of other market and policy factors that are being addressed through increasing action on local and state housing policy.[92] Since all electric homes have reached effective cost parity with gas homes, conceivably, if such homes obtained the same premium on the market, the allowance would effectively be a subsidy to the developer.

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[88] Bakhshi, P. *et al*. *Public Policy for Net Zero Homes and Affordability*. https://hbrama.com/wp-content/uploads/2023/05/Public-Policy-for-Net-Zero-Homes-and-Affordability-Final-6-14-23.pdf (2023).
[89] D.P.U. 23-80, Final Order, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19281184
[90] D.P.U. 23-150, Final Order, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19692111
[91] Interagency Rates Working Group: https://www.mass.gov/info-details/interagency-rates-working-group
[92] Kennedy, A. et al. *The Greater Boston Housing Report Card 2023*. The Boston Foundation (2023) https://www.tbf.org/news-and-insights/reports/2023/november/2023-greater-boston-housing-report-card

R3.5 Proposals from the 20-80 Regulatory Designs Report

The 20-80 Independent Consultant Report Part II on Regulatory Designs identified four potential reforms[93] to line extension allowances. In this section, we summarize the reasons why these four potential reforms would be insufficient to align the future of gas system expansion in Massachusetts with the Department's climate and affordability mandates and the state's climate goals. Where pertinent, we reference actions taken by other public utility commissions.

R3.5.1 Reduce customer revenues supporting allowances

For service extensions, National Grid established minimum charges that effectively reduce existing customer revenues, supporting investment. The Department could require the use of minimum charges or place a cap on the allowance per customer that has a similar effect of increasing the upfront customer contribution. Both of these strategies would increase the customer-facing cost of gas, while reducing the burden of risk on existing customers.

Since 2012, Oregon's NW Natural has provided a fixed allowance to different customer classes depending on their appliances. In 2022, the Public Utility Commission of Oregon ordered that this fixed allowance should be reduced and that a more detailed review of allowances be undertaken.[94]

R3.5.2 Shorten the payback period for calculating allowances

Currently, the LDCs typically use a 20- or 10-year payback period to calculate line extension allowances (Table 7). This proposal attempts to address one of the issues with gas expansion subsidies in the energy transition: namely, the risk that new gas customers leave the system or reduce their gas usage considerably before their line extension allowance is "paid off."

From the ratepayer's perspective, this approach would result in the same result as the direct reductions discussed above: smaller allowances and higher customer contributions for new gas service. We note that this does not apply to service-only connection default allowance practice.

In 2021, the Washington Utilities and Transportation Commission ordered the state's natural gas companies to adopt a 7-year timeline for the calculation of line extension allowances.[95]

R3.5.3 Raise the IRR required for calculating allowances

This proposal would result in the allowance amount being decreased and the CIAC amount increased, therefore it would have the same ratepayer impact as the above two proposals, namely by diminishing gas expansion subsidies. In financial modeling, higher IRRs are associated with riskier investments. Raising the IRR in this context attempts to address the fact that the allowance is an increasingly risky investment for the utility, due to the considerable risks of new customers

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[93] Page 36, Energy and Environmental Economics & Scott Madden Management Consultants. The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Part II Regulatory Designs. https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Regulatory%20Designs.pdf (2022).

[94] Public Utility Commission of Oregon, *UG 435 Order*. October 24, 2022, https://apps.puc.state.or.us/orders/2022ords/22-388.pdf

[95] Washington Utilities and Transportation Commission, *DOCKET UG-210729 Order 01 Authorizing And Requiring Tariff Revisions*, October 29, 2021, https://apiproxy.utc.wa.gov/cases/GetDocument?docID=67&year=2021&docketNumber=210729

leaving the system or reducing usage in the future in the context of the energy system transformation discussed throughout this report.

While this proposal may seem attractive for similar reasons to proposals (1) and (2), it has additional issues. In particular, the current IRR used in utilities' DCF models is the utility's weighted average cost of capital (WACC). If a higher IRR than the WACC were used in calculating the line extension allowance, it would amount to a tacit acknowledgment that the allowance is a significantly riskier investment than the rest of the utility's capital investments as a whole, which are generally subject to the WACC. While this may accurately reflect reality, it may also have unforeseen impacts on the utilities (for example, through credit ratings) and ratepayers (for example, through the utility pursuing riskier investments in system expansion with the expectation of higher returns). In sum, using a different IRR specific to allowances may create unnecessary financial risks for both utilities and ratepayers.

R3.5.4 Require new customers to guarantee revenues supporting allowances

Here, the allowance practice would continue as usual, but if a customer were to leave or significantly reduce usage, they would still be responsible for paying the expected revenues. This proposal mitigates the risk of unrecoverable costs. However, it likely does not address climate-related issues, and nor does it effectively manage a transition beyond gas.

At best, it would create a new contractual obligation that may prompt customers to consider the long-term implications of remaining on gas. However, it is unlikely that this would sway customers who are intent on gas and fail to recognize the fuel's long-term challenges. For customers who are subject to the guarantee, there is then little incentive to reduce or eliminate gas use, and they are stuck with both the cost of the gas system and greenhouse gas compliance costs.

This would also disadvantage renters or subsequent owners who could be responsible if the guarantee was tied to the meter.

R3.6 Considerations for Implementation

As the Department advances a common framework for new service connections, it will need to consider several implementation needs. These include:

- Administrative needs – As we have shown, allowance calculations can vary significantly across the LDCs, and we were unable to assess the actual practice and how they are applied. Greater scrutiny and oversight of allowance policy to ensure consistency and compliance will require more administrative and LDC capacity and process. Alternatively, an outright elimination can reduce administrative requirements.
- Timeline for implementation – The California Public Utilities Commission and Colorado legislation required immediate elimination of allowances. Gas companies in California had argued for a phased approach over several years depending on project type.
- Allowance of exceptions and who grants exceptions – We consider the conditions for exceptions with respect to climate goals in R3.2. While CPUC disallowed allowances, it allowed gas companies to petition for exceptions, noting that there may be limited instances where the expansion of the gas system to new customers delivers benefits. Several gas companies proposed to develop their own criteria for exceptions and have each company responsible for approving exceptions. CPUC rejected this approach. The criteria that CPUC[96] will use for evaluating exemptions are:
    - *The project will lead to a demonstrable reduction in GHG emissions;*
    - *The gas line extension required for the project is consistent with [state] climate goals ... and;*
    - *The project applicant demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.*
- Allowance of payment plans and surcharges – The Department approved a proposal by Eversource in their last rate case to surcharge new customers for a period as an alternative to an upfront CIAC payment. Additionally, we observed an interest-free monthly payment calculation in Unitil's calculator. Customers can independently seek similar financing, e.g., a mortgage for new construction. If the department were to increase the customer contribution, the Department may have to determine if LDCs can provide such financing and under what circumstances that financing can be offered (timeline, interest rate).

[96] California Public Utilities Commission. (2022). *Decision Eliminating Electric Line Extension Subsidies for Mixed-Fuel New Construction and Setting Reporting Requirements* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF

Conclusion & Guidance for the Department's Review

In the three prior chapters, we answered the Department's three questions. We showed that there is an increasing risk that existing customers will subsidize new customers without realizing future benefits due to the increasing expansion cost, declining consumption, and the potential for early departures. We also argue that allowances are no longer in the public interest as climate and affordability considerations require a transition away from gas, specifically by avoiding growth.

In its 20-80-B order, the Department stated that "our 'beyond gas' future will ...involve close scrutiny of the extent to which additional investment is necessary, with an eye toward minimization of costs that may be stranded in the future as decarbonization measures are implemented in the natural gas industry."[97] In issuing this order, the department recognized that compliance with the state's climate targets requires substantially lower gas consumption and a smaller gas system serving a smaller number of customers.

In initiating its review of allowances, the Department's Order and Hearing Office Memo provided the LDCs with an opportunity to demonstrate how allowances align with climate goals and benefit existing customers in the broader context of the Department's *Investigation into the Future of Gas*. The Department specifically asked the LDCs to focus on three areas in their review.

The first was to report "the number of *de facto free extension allowances"*. The LDCs provided this data (Figure 5) except for Liberty, which reported total new services and provided CIAC cost data. Since 2018, the number of free allowances has been 80% of all connections reported by the 3 LDCs (Berkshire, National Grid, and Eversource) that reported connections with and without a CIAC.

The second focused on "whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered." The LDCs' calculators demonstrated that they have a methodology for recovering investments. However, practice differs significantly among the LDCs, resulting in notable differences in allowances. Further, the LDCs do not sufficiently validate how these models are applied in practice or provide sufficient data to conduct such a validation.

Additionally, the LDCs testimony neglects to address evolving drivers of declining demand and potential early customer departures – despite such drivers existing because of current policy and being illustrated as necessary to meet affordable transition goals in the 20-80 Pathways Report.

Finally, the LDCs were asked to review "whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions." As we respond to the Department's Second Question above, the LDCs fail to explain how allowances support state climate policy. Here, National Grid and Unitil argued that oil-to-gas conversions are aligned with climate policy, with Eversource providing a more tempered perspective and Unitil and Liberty not directly answering the question.

[97] D.P.U. Order 20-80B at page 15

We note that only Berkshire explicitly opposed eliminating line extension allowances, citing that doing so may be punitive to new customers. We also note that National Grid claimed that its adoption of a minimum CIAC was intended to address the increasing cost of new connections while discouraging customer growth. Eversource noted that it was taking steps to implement a similar policy, while Unitil and Fitchburg did not take a position.

There is significant inconsistency in allowance practice across the LDCs. If the granting of allowances continues, a greater level of regulatory scrutiny is needed to ensure consistent practice. However, increasing connection costs and increasing risk of declining revenues means that new customers should bear more responsibility for costs than they do today. Further, the need to prudently align the gas system with climate law requires a significant curtailment in growth.

These factors underlie the decisions in Colorado and California to eliminate allowances. As such, there is both rationale and precedent for the Department to take either an incremental approach or eliminate allowances altogether.

In 2013, the National Regulatory Research Institute published a report titled *Line Extensions for Natural Gas: Regulatory Considerations*.[98] The report provided an exhaustive evaluation of line extension practices and how such policies should be designed with respect to new and existing customers, the utilities, and the public interest. In particular, the report concluded that determining public benefits is important for justifying line extension allowances. The report further noted on page 36 that allowances may be a "bad policy" when:

> *"In the absence of large-scale public benefits or utility internal efficiencies, subsidies funded by a utility's existing customers come across as both unfair and economically inefficient:*
>
> 1. *It is unfair to existing customers because they are involuntarily funding new customers at no benefit or less-than-commensurate benefits to them.*
> 2. *It is also economically inefficient if they induce additional energy consumers to switch to natural gas when they otherwise would not have if they had to pay the full cost of line extensions.*
> 3. *Subsidies also may distort competition among energy sources. By offering new gas customers subsidies, suppliers of oil, propane, and electricity would be at a disadvantage.*
> 4. *Even with public benefits, subsidies funded by existing customers might not constitute the most cost-effective approach for increasing the number of new gas customers and gas consumption. Funding from taxpayers or utility shareholders might create less inefficiency.*
> 5. *Even if policymakers can justify subsidies for fuel switching and line extensions, they need to ask which forms would be most cost-effective and create the least distortion"*

[98] Costello, K. *Line Extensions for Natural Gas: Regulatory Considerations*. https://pubs.naruc.org/pub.cfm?id=B377212B-EFB0-EAB3-E524-88AB6D4332A6 (2013).

We end the report by offering a list of evaluation questions that the Department should consider as it examines whether allowances continue to be in the public interest:

Table 11. Potential evaluation criteria for the utility of allowances and our answers are informed by our analysis in this report.

Consideration evaluation question	Response informed by this analysis
Alignment with the fairness to existing customer consideration: *Does the provision of allowances have adverse impacts on existing customers?*	Yes. Allowances are effectively loans from investors and existing customers to new customers, with the expectation that adding new customers brings long-term benefits. Such benefits are less likely to materialize at the same time that this loan is at increasing risk of being unrecovered given that most new customers today will need to reduce their gas use in the future.
Alignment with the affordability consideration: *Are allowances in the public interest with respect to enhancing energy affordability by growing the gas system?*	No. Gas's long-term affordability is being challenged by increasing costs spread over a dwindling customer base. Allowances offer an incentive for new customers who may not be suitable long-term customers of the gas system. The addition of new customers subsidized by allowances increases system costs and, therefore, investment risk.
Alignment with a economic efficiency consideration: *Do allowances create the potential for economic inefficiency by inducing customers to switch to gas when there are other viable options?*	Yes. Today, customers have a variety of cost-effective home heating options. Allowances obscure the true cost of gas relative to these options.
Alignment a climate law consideration: *Do allowances align well with Massachusetts climate law?*	No. Allowances promote expansion of the gas system and lock-in of gas infrastructure in situations where reasonable alternatives would work well.

Appendix 1: Review of New Customer Costs by LDC

Liberty

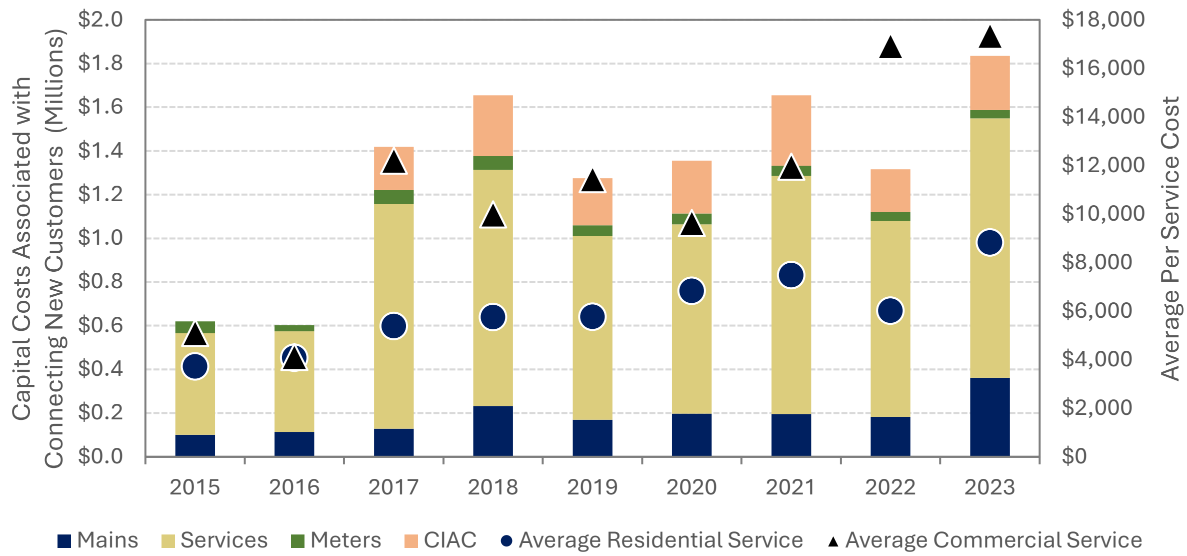

Figure 17. New customer costs for Liberty Utilities. Source: Exhibit Liberty-3, which is also Schedule I from Liberty's 2024 Peak Period RDAF filing (D.P.U. 24-120). Main costs were allocated to the residential and commercial sectors based on the shares of new customer additions.

Liberty submitted a time series of costs and CIAC values.[99] Average new residential service costs in Liberty territory were $5,837.88 in 2023, representing a sharp increase from prior years. Commercial connections exceeded $10,000 and were much higher than in earlier years. Both cases demonstrate a downward trend in new connections and a notable sharp increase in average costs in the last year or two. Figure 17 shows the total reported and average customer addition costs for Liberty from 2015-2023. For 2021-2023, the average service costs were:

Table 12. Average new customer capital costs for Liberty from 2021-2023.

	Residential	Commercial
Mains	$1,865	$1,130
Service	$3,366	$6,663
Meters	$96	$1,250
CIAC	$1,023	$2,652
Total	**$6,350**	**$11,694**

Liberty's filing reports a per-customer meter cost of $96 for residential and $1250 for commercial in 2014, 2024, and most years in between.

[99] Exhibit Liberty-3 or D.P.U. 24-120 Ex. DPU24-XX(PeakRDAF)_InitialFiling.pdf

UNITIL

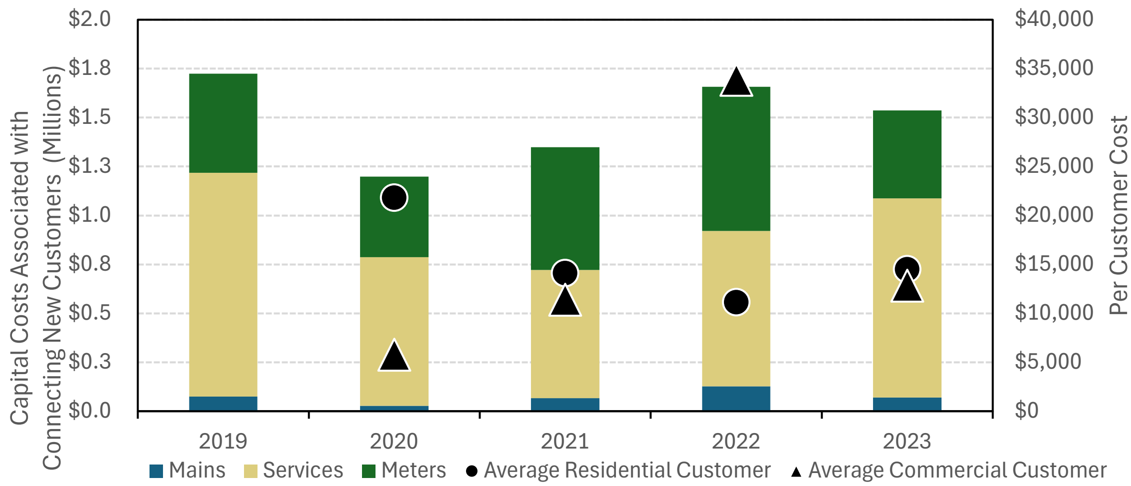

Figure 18. New customer costs for Unitil. Source: Unitil RDAF filings[100]

Figure 18 shows the total reported and average customer addition costs for Unitil from 2019-2023. For 2021-2023, the average residential service costs were:

Table 13. Average new customer capital costs for Unitil from 2021-2023.

	Residential	Commercial
Mains	$808	$8,203
Service	$7,449	$7,965
Meters	$4,816	$3,262
Total	**$13,072**	**$19,430**

Additionally, we identified comparable values from Unitil GSEP's filing for their blanket service upgrades:

Service replacements, average actual cost	$5,937	*23-GREC-01 Ex. Unitil-CLTB-3, Sch. 4*
Specific service transfers, average estimated cost	$5,684	*23-GSEP-01 Ex. JRCL-3 Attachment B (Sheet3)*
Blanket service upgrade, average estimated cost	$13,356	*23-GSEP-01 Ex. JRCL-3 (Plan 2024-2028)*

[100] D.P.U. 20-88, 21-22, 21-95, 22-11, 22-102, 23-18, 23-77, 23-22, 24-118

Berkshire

Berkshires' testimony reported "average costs quoted to potential customers for 2023[101]:

- New services: $4,618.09
- Cost of CIAC: $921.00
- Cost minus $0 CIACs: $2,936.69

We assume that the last value represents the average project cost or line extension allowance for projects that did not charge a CIAC. Berkshire reported that 91 projects in 2023 did not require a CIAC, whereas 35 did.[102]

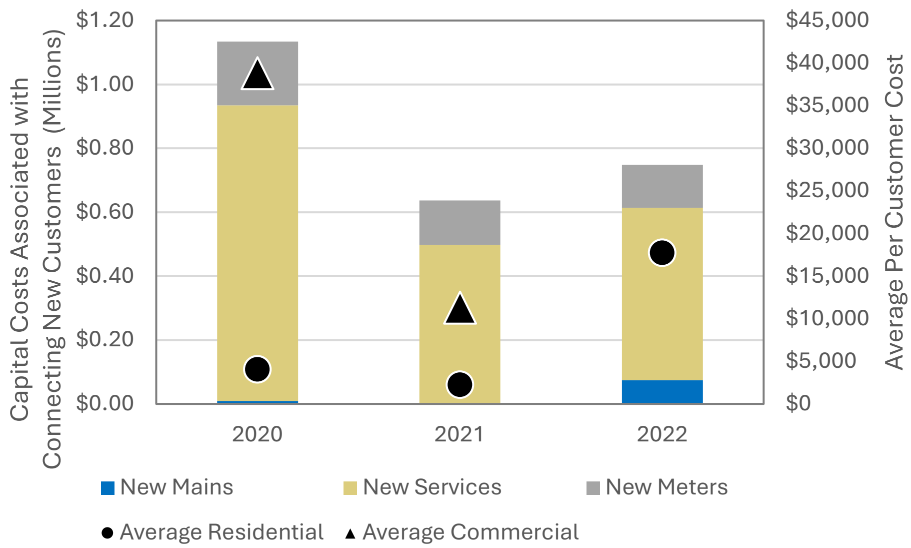

Figure 19. New customer costs for Berkshire Gas Company. Source: Berkshire Peak Period RDAF Filings[103] Berkshire's 2024 filing (24-124) has identical capital costs to 2023 and was excluded. According to the 2022 and 2023 filings, Berkshire only added one new commercial customer.

Figure 19 shows the total reported and average customer addition costs for Berkshire from 2020-2022. Average costs are shown in Table 14.

Table 14. Average new customer capital costs for Berkshire Gas for 2020-2022.

	Residential	Commercial
Mains	$138	$127
Service	$3,225	$2,964
Meters	$780	$717
Total	**$4,143**	**$3,808**

[101] Exhibit BGC Line Extension Testimony 8.13.24.pdf at 7
[102] Exhibit BCG-6
[103] D.P.U. 20-89, 21-99, 22-91, 23-74

In its 2023 GSEP Filing, Berkshire, the average cost for bare steel and copper service replacements was $7,728. [104] Berkshire's 2023 GREC filing reported a cost of $5,976 and $5,182 for service replacements and service transfers.[105]

Berkshire's share of new customers is small (Figure 5) and likely benefits from lower costs in Western Mass, while new customers are more disproportionately likely to be considered smaller residential. In recent years, Berkshire's service territory has seen a modest population decline.

According to RADF filings in 2021 and 2022, Berkshire's Capital Costs Associated with New Customers totaled $684,957 and $1,134,54, respectively, with only $19,296 being booked to mains in 2022. Based on its annual returns, Berkshire added a net of 116 and 49 residential customers in 2021 and 2022 and lost a net of 29 and 114 commercial customers in those years. Based on its RDAF schedule K filings Berkshire gained 169 and 22 customers in 2021 and 2022, and gained 27 and 1 commercial customers in those years. In Ex BGC-6, they report 147 and 191 services installed in these two years, with 71 and 36 requiring a CIAC.

[104] *23-GSEP-02 Ex. BGC-JP2 Pg. 14 & 15*
[105] *23-GREC-02 Ex. BGC-JP-4 Pg. 1* 2022 GSEP Summary Costs

EVERSOURCE

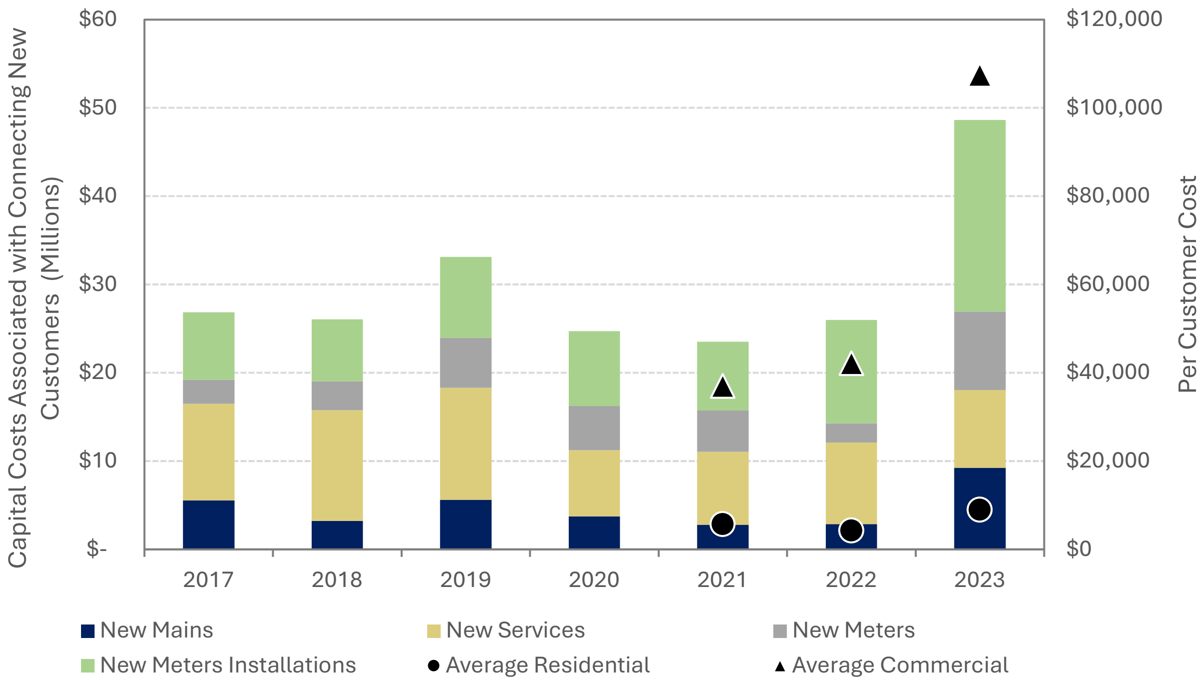

Figure 20. New customer costs for NSTAR service territory. Source: Costs obtained from Schedule I of NSTAR's 2024 peak period RADF filing (24-112). New customer counts were obtained from this and prior year RDAF Schedule K filings (23-69, 22-88, 21-87). Average customer costs were calculated based on rate class allocation factors provided in Schedule I.

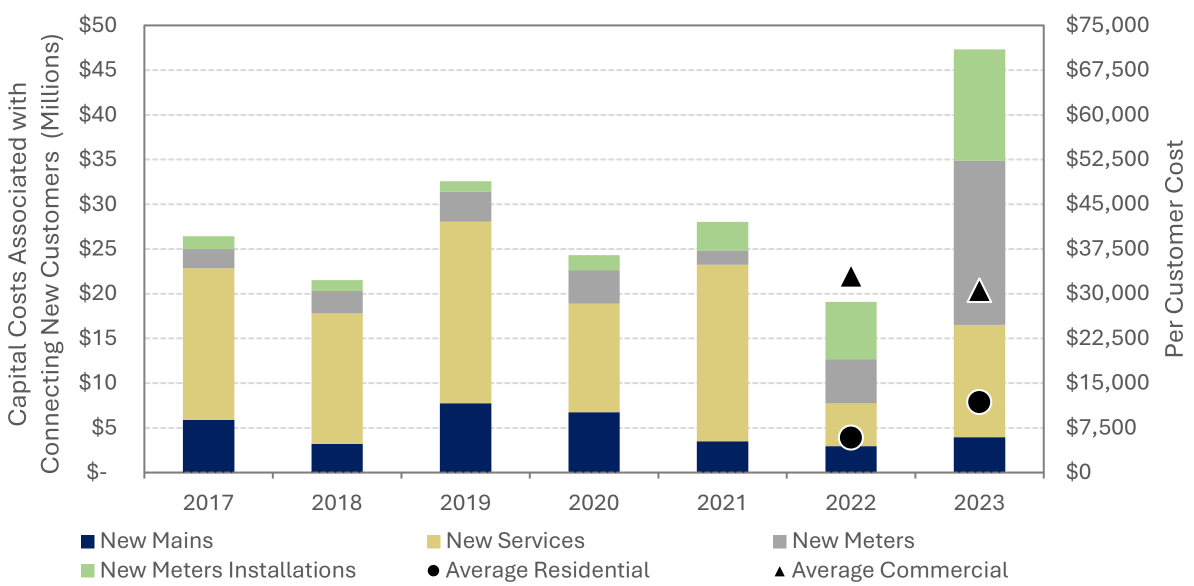

Figure 21. New customer costs for EGMA service territory. Source: Costs obtained from Schedule I of EGMA's 2024 peak period RADF filing (24-112). New customer counts were obtained from this and prior year RDAF Schedule K filings (23-69, 22-88, 21-87). Average customer costs were calculated based on rate class allocation factors provided in Schedule I.

Table 15. Average new customer capital costs for NSTAR and EGMA for 2021-2023.

	Residential		Commercial	
Category	***NSTAR***	***EGMA***	***NSTAR***	***EGMA***
Mains	$956	$618	$8,731	$6,730
Service	$1,694	$3,661	$15,483	$6,956
Meters	$1,011	$1,968	$9,235	$10,290
Meter Installations	$2,646	$1,749	$24,174	$9,142
Total	$6,306	$7,996	$57,622	$33,118
w/o Meter	$2,650	$4,280	$24,214	$13,686

Eversource did not provide cost estimates in its response. Figure 20 and Figure 21 show capital costs associated with connecting new customers and per-customer costs based on RDAF filings. Average per-customer costs for 2021-2023 are listed in Table 15.

The large contribution of meter and meter installation costs are notable here. We were able to align "New Meter", and "New Meter Installations" with reported additions in their respective utility plant accounts (381 and 382) in their NSTAR's and EGMA's 2023 Annual Returns, while main (367) and services (380) were well below reported additions (likely due to GSEP spending). Eversource may be reporting meter replacements as a capital cost associated with connecting new customers which would result in per-customer values being an overestimate. Table 15 illustrates the impact of removing this cost, however new customer meter costs can conservatively be estimated to cost in the 100's for residential and at least $1,000 for commercial. The use of rate allocation factors here may not accurately reflect actual costs.

For comparison, Eversource's costs *for service replacements only* are reported in 2023's GSEP filing, incurring $7,385 of direct costs and $17,599 of fully loaded costs as broken down by spending category in Table 16.[106] In Eversource's 2024 GREC filing, the average service replacement costs were reported to be $9777.[107]

Table 16. D.P.U. 23-GSEP-06 Exhibit ES-RJB-2.xlsx

Cost Category	Cost	Share of Total Cost
Contractor	$4,796.74	27%
Materials	$93.70	1%
Labor	$400.45	2%
Paving	$1,245.22	7%
Police	$321.08	2%
Other	$528.04	3%
Overheads and Loaders	$10,214.21	58%

[106] *23-GSEP-06 Ex. ES-RJB-2.xlsx (Unit Cost Summary by Work Group)*
[107] *24-GREC-06 Ex. ES-TCD-7 (Service Investment).xlsx*

NATIONAL GRID

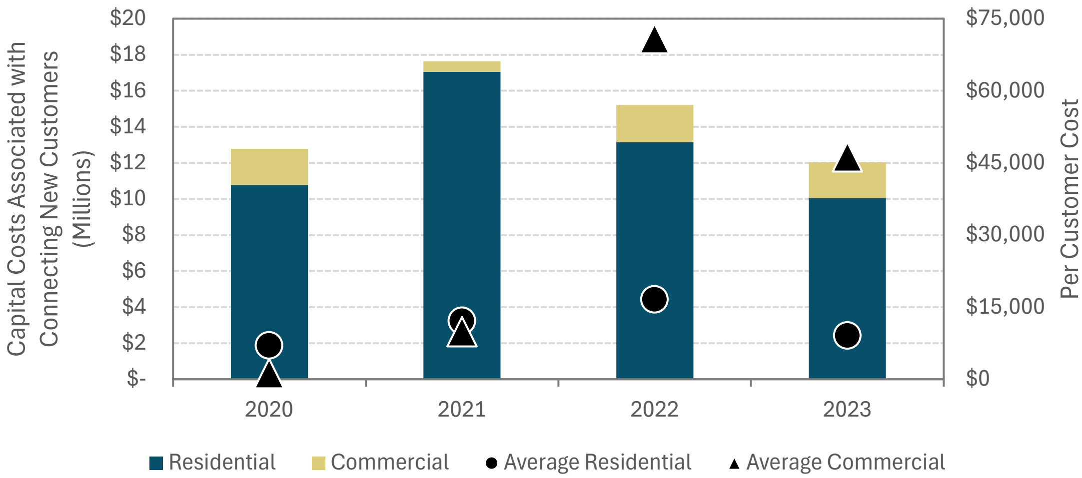

Figure 22. New customer costs for Colonial service territory. Source: Costs obtained from Schedule I of National Grid's 2024 peak period RADF filing (24-108). New customer counts were obtained from this and prior year RDAF Schedule K filings (23-78, 22-101, 21-89). Average customer costs were calculated based on Schedule I rate class allocation factors.

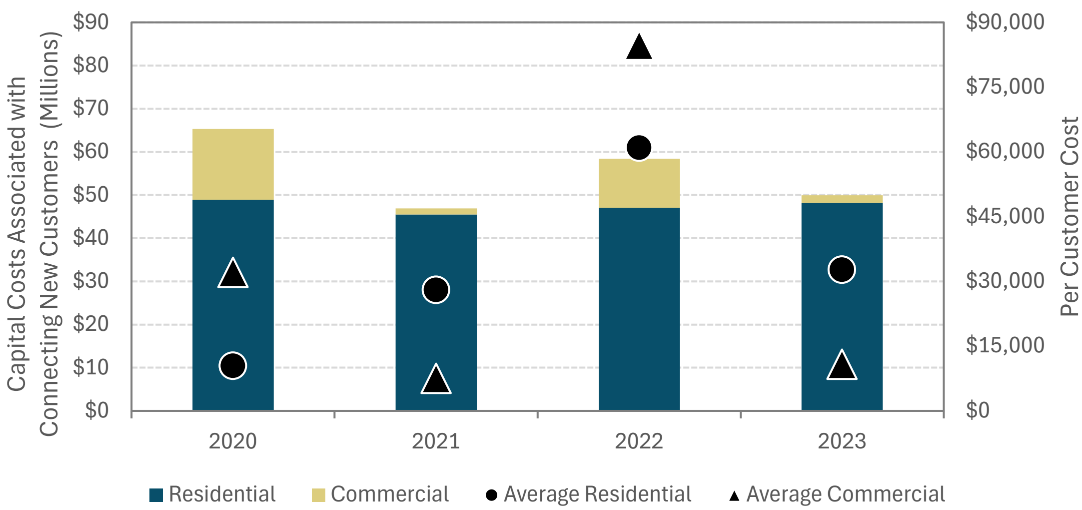

Figure 23. New customer costs for Boston Gas service territory. Source: Costs obtained from Schedule I of National Grid 2024 peak period RADF filing (24-108). New customer counts were obtained from this and prior year RDAF Schedule K filings (23-78, 22-101, 21-89). Average customer costs were calculated based on Schedule I rate class allocation factors.

Table 17. Average new customer capital costs for Colonial and Boston Gas for 2021-2023.

Residential		Commercial	
Colonial	***Boston***	***Colonial***	***Boston***
$10,577	$22,140	$ 9,574	$31,094

National Grid did not offer specific cost estimates in its response. Figure 22 and Figure 23 The graphs show capital costs associated with connecting new customers and per-customer costs based on RDAF filings. National Grid's investment declined 30% from 2020 to 2023, but average costs continued to increase.[108] Three-year average per-customer costs are shown in Table 15. The values for Colonial service territory (largely centered around Lowell and on the Cape) were similar to those reported in the 20-80 Pathways Report's methodology (Figure 9), while Boston gas territory experienced a significant increase in costs relative to the previous estimate.

For comparison, National Grid's 2023 GREC filing included a list of *service-only* replacement projects that averaged $3,337 in direct costs and $2,918 in indirect costs – totaling $6,255.[109]

Table 18. Customer charge rates for service projects.

Project Type	Customer Charge	Additional Context
Tear Down Rebuild	$3,600	Up to 4" plastic pipe
Relocation	$2,000 (<10ft) $3,100 (11-100ft) $4,500 (>100ft)	Up to 4" plastic pipe
New Residential Heating	$1,800	Up to 4" plastic pipe, service only
New Residential Non-Heating	$4,200	Up to 4" plastic pipe, service only
Commercial Service Minimum Charge	Up to 4" - $1,800 6" - $3,600 8" - $5,400 12" - $7,200	Service only

National Grid's did report customer charges for new or replacement services, summarized in Table 18. According to the National Grid Policy relocation and rebuild costs should be borne by the customers. It is notable that these projects are lower than average new customer and GSEP service costs.[110] Such projects also likely require less indirect or customer acquisition and support costs.

Additional cost data can be found in the static output of National Grid's line extension IRR Model (Exhibit NG-5).[111] Specifically, the exhibit included several unit pricing values representing new service costs for the Cape region of the Colonial Gas territory.[112] In its current selection of options, the model apparently provides a $6996.96 estimate for a new service (<100'ft without main work) in the Cape region of Colonial Gas territory. Additional minimum costs and additional per foot costs for main work, service with main work, and meters ($580 per customer residential) are also provided. Minimum main work requires $12,064 in base costs, plus $2,564 and $1,544 in paving and police adders.

[108] Lower customer additions in 2022 contributed to a spike in average in that year.
[109] *23-GREC-03: Ex. NG-AS-MT-3 (*Pipeline Replacement: Actual Costs), average of middle 80% of project values for non-cathodically protected steel replacements.
[110] Exhibit NG-2 Tariff MDPU No. 61.2.pdf
[111] Exhibit NG-5 MA-G IRR Model_Redacted.pdf
[112] Ibid. Page 24

The model further provides calculated CIAC costs[113] using standard rates and demand levels. For this region, the output implies a CIAC need of $9,835

Interestingly, an anonymous user on Reddit posted in 2022 that National Grid quoted $102,584 to extend a main gas line 19 feet and install 200 feet of service line in Arlington, MA.[114] While such anonymous postings should be viewed with skepticism,[115] there is certainly evidence of prohibitive costs. Based on factors provided in NG-5, the project cost would require a base cost for the main extension of $16,173.07 and $4,924.19 for the service, totaling $21,097.26. Our discounted cash flow model, built to emulate the LDCs' models (described below), estimated a CIAC of $28,691. On page 25 of the Exhibit, a CIAC of $29,439 is estimated for the representative area of Arlington. Applying a discounted cash flow model results in a CIAC of $28,690.57, greater than the project costs largely because of the tax on net revenues. Based on today's energy prices and gas rates, the payback of such a high-cost gas connection relative to propane service would take 15 years (at a customer discount rate of 4%)

The higher costs indicated by the calculator's CIAC tables in other regions indicate that a significantly higher CIAC is possible. The redacted estimates on page 29 of Exhibit 5 could be used to better validate the estimate.

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[113] Ibid. Page 25
[114] *$102,548 quoted by National Grid to have main gas line extended 19 ft from neighbor house.* https://www.reddit.com/r/massachusetts/comments/11kzequ/102548_quoted_by_national_grid_to_have_main_gas/#:~:text=I%20was%20recently%20quoted%20$102,548%20to%20have%20gas%20line%20in
[115] Such geometries are rare in Arlington