COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

CLIMATE COMPLIANCE PLANS

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

DIRECT TESTIMONY OF

Michael J. Walsh

On behalf of

THE MASSACHUSETTS OFFICE OF THE ATTORNEY GENERAL

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I. INTRODUCTION

Q. Dr. Walsh, please state your full name and email address.

A. My name is Michael J. Walsh. My email address is mjw@groundworkdata.org.

Q. By whom are you employed?

A. I am a managing partner at Groundwork Data. Groundwork Data is a Massachusetts-based firm that offers research, advisory, and technology services on issues related to the future of heat in buildings.

Q. Please summarize your professional and educational background.

A. I hold an A.B. in Chemistry (A.C.S. Certification) from Colby College, and a Ph.D. in Environmental Engineering from Cornell University. My doctoral research and education focused on marine biogeochemistry. I conducted postdoctoral research as a fellow at the Bentley University Center for Integration of Science and Industry on the topics of integrated macro-energy system modeling, lifecycle and technoeconomic assessment, and technology transitions in the bioenergy industry.

From 2017 to 2019, I served as the technical lead of the Carbon Free Boston Study at the Boston University Institute for Sustainable Energy, overseeing a comprehensive technical analysis and stakeholder engagement exercise. In 2019, I was hired by the Cadmus Group, where my primary responsibility was as project director for the Massachusetts 2050 Decarbonization Roadmap Study ("2050 Roadmap"), a comprehensive technical analysis and stakeholder engagement exercise that served as the foundational research for the

Executive Office of Energy and Environmental Affairs' ("EEA") decarbonization planning.

In 2021, I launched an independent practice that evolved into Groundwork Data focused primarily on the future of gas and future of heat. In this role, I have overseen several studies and projects on the "future of gas" and the "future of heat" (D.P.U. 20-80) in Massachusetts and other jurisdictions. To date, Groundwork Data has only worked with governmental or non-profit public interest organizations.

Q. Please summarize your experience testifying before public utility regulatory agencies.

A. My usual role in testifying before public utility regulatory agencies is in an advisory capacity as a decarbonization expert. In the Commonwealth, I have testified before the Massachusetts Department of Public Utilities ("Department") on behalf of the Conservation Law Foundation ("CLF") on Liberty Utility's petition for approval of an agreement to purchase renewable natural gas from Fall River RNG, LLC (D.P.U. 22-32). I have also acted as a non-testimonial expert in other dockets as a consulting expert and commenter, notably D.P.U. 20-80.

I have testified before the Rhode Island ("R.I.") Public Utilities Commission ("P.U.C.") on behalf of the CLF on the 2024 and 2025 infrastructure, safety and reliability proceedings (R.I. P.U.C. 23-49-NG and R.I. P.U.C. 24-55-NG). I have also participated as a technical expert in the R.I. "Future of Gas" investigation (R.I. P.U.C. 22-01-NG) on behalf of the CLF and Sierra Club. Recently, I have testified before the Colorado Public Utilities

Commission on Xcel Energy's 2025-2030 Gas Infrastructure Plan (CO. P.U.C. 25A-0220G) on behalf of Rewiring America.

Q. On whose behalf are you submitting testimony?

A. I am testifying as an independent expert on behalf of the Massachusetts Attorney General's Office ("AGO"), Energy and Ratepayer Advocacy Division.

Q. Please provide an overview of your testimony.

A. My testimony is organized as follows:

- Section II defines the "climate compliance" standard being evaluated in these proceedings as it applies to the local gas distribution companies[1] ("LDCs" or "Companies"). The section then demonstrates how the LDCs are not on a pathway towards climate compliance;
- Section III assesses the LDC's proposals for new connections in their Climate Compliance Plans ("CCPs") and filings related to the investigation into line extension allowances; and
- Section IV evaluates the low-carbon fuel ("LCF") proposals put forth by the LDCs in their respective CCPs.

II. CLIMATE COMPLIANCE: GREENHOUSE GAS ("GHG") EMISSIONS

A. Climate Compliance Requires the LDCs to Prudently Right-Size the Gas System.

Q. What does Order D.P.U. 20-80-B require of utilities to demonstrate through their CCPs?

[1] The Boston Gas Company d/b/a National Grid ("National Grid"), Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty"), Eversource Gas Company of Massachusetts d/b/a Eversource Energy ("Eversource"), and NSTAR Gas Company d/b/a Eversource Energy ("NSTAR") (collectively, the "LDCs" or "companies").

A. D.P.U. Order 20-80-B[2] directs the LDCs to file CCPs "demonstrating how each LDC proposes to: (1) contribute to the prescribed [GHG] emissions reduction sublimits set by EEA for both Scope 1 and Scope 3 emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably using known and market-ready technology available at the time of the filing; (3) use pilot or demonstration projects to assist in identifying investment alternatives; (4) incorporate the evaluation of previous metrics; and (5) implement recommendations for future plans."[3]

Q. What are Scope 1, Scope 2, and Scope 3 GHG Emissions?

A. The "Scope" framework is an accounting mechanism designed to differentiate emissions of a reporting entity and attribute them consistently and reliably to specific activities.[4] The U.S. Environmental Protection Agency ("EPA") defines each scope as:

- Scope 1 emissions are "direct" GHG emissions that occur from sources that are controlled or owned by an organization (e.g., emissions associated with fuel combustion in boilers, furnaces, vehicles).[5]
- Scope 2 emissions are "indirect" GHG emissions associated with the provision of purchased electricity, steam, heat, or cooling.
- Scope 3 emissions are the results of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly affects in its value chain. An organization's value chain consists of both its upstream and downstream activities.

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2 *Future of Gas*, D.P.U. 20-80-B, Order (Dec. 6, 2023).

3 *Id.* at 135.

4 Janet Ranganathan, et. al., *GHG Protocol Corporate Accounting and Reporting Standard*. WORLD RESOURCES INSTITUTE (Mar. 2004), https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf.

5 EPA, *Scope 1 and Scope 2 Inventory Guidance*, https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance.

> Scope 3 emissions include all sources not within an organization's scope 1 and 2 boundary. The scope 3 emissions for one organization are the scope 1 and 2 emissions of another organization. Scope 3 emissions, also referred to as value chain emissions, often represent the majority of an organization's total GHG emissions.[6]

In the context of the 20-80-B Order, Scope 1 largely refers to emissions from assets that an LDC owns, specifically fugitive methane emissions from gas infrastructure. Scope 1 also includes other operational emissions such as those from the energy needed to operate the pipe system, heat company buildings, and from the combustion of LDC vehicle fuels. Scope 3 refers to value chain emissions, specifically the consumption and combustion of utility gas by gas customers. The Scope framework is primarily used by corporate entities to help them manage GHG compliance risks and identify reduction opportunities.[7] Pursuant to G.L. c. 21N, §3A, the Commonwealth monitors and regulates emissions across several defined activity sectors.[8] The Commonwealth does not typically use the "scope" terminology in its monitoring and regulation. I understand the Department uses the "scope" terminology to highlight the LDC's responsibilities towards and influence of emissions generated from utility gas consumption in the residential, commercial, and industrial building sectors ("Scope 3"), while also recognizing the need to understand and

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[6] EPA, *Scope 3 Inventory Guidance*, https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance.

[7] EPA, *Scopes 1, 2 and 3 Emissions Inventorying and Guidance*, https://www.epa.gov/climateleadership/scopes-1-2-and-3-emissions-inventorying-and-guidance.

[8] These sectors include electric power, transportation, commercial and industrial heating and cooling, residential heating and cooling, industrial processes, and natural gas distribution and service.

prudently address emissions from LDC operations ("Scope 1"), particularly those related to fugitive methane released from distribution assets.

Q. What are the sublimits that the LDCs' Scope 1 and Scope 3 emissions are subject to?

A. LDCs' fugitive methane Scope 1 emissions are subject to the "Natural Gas Distribution & Service" sublimits, and Scope 3 emissions are predominantly subject to the "Residential Heating & Cooling" and "Commercial & Industrial Heating & Cooling" sublimits. Currently, sublimits for 2030 and 2050 have been established by EEA as described herein. Chapter 21N establishes the following statewide benchmark mandates:

- By 2030, achieve a 50 percent emissions reduction below the 1990 level;[9]
- By 2040, achieve a 75 percent emissions reduction below the 1990 level;[10]
- And by 2050, "achieve at least net zero statewide greenhouse gas emissions; provided, however, that in no event shall the level of emissions in 2050 be higher than a level 85 per cent below the 1990 level."[11]

Chapter 21N §3(b) also directs the EEA Secretary to adopt interim statewide emissions limits for 2025, 2030, 2035, 2040, and 2045, with the 2030 and 2040 limits achieving at least the threshold limit listed above. Section 3(d) requires each interim limit to be accompanied by a "roadmap plan to realize said limit." Chapter 21N §3A directs the

9 G.L. c. 21N, § 4(h).

10 *Id*.

11 G.L. c. 21N, § 3(b).

Secretary to establish sector-specific sublimits for 2050. The Secretary has adopted sublimits for 2030[12] and 2050,[13] which are listed in Table 1 below.

Table 1. Statewide emissions limits and sublimits (% reduction from 1990)

		2030		2050	
		Reduction	Limit ($MMTCO_2e$)	Reduction	Limit ($MMTCO_2e$)
Statewide Limit		50%	62.2	85%	9.4
Sectoral	*Residential Heating and Cooling*	49%	7.8	95%	0.8
	Comm. & Ind. Heating and Cooling	49%	7.2	92%	1.1
	Transportation	34%	19.8	86%	4.1
	Electric Power	70%	8.4	93%	2.0
	Natural Gas Distribution & Service	82%	0.4	72%	0.5
	Industrial Processes	-281%	2.5	-27%	0.8

In asking how the LDCs plan to "contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1 and Scope 3 emissions,"[14] the Department established that the LDCs must consider both the established interim limits, sector-specific sublimits, and 2050 emissions limits.

Q. What do the net zero statewide limit, interim limits, and sublimits seek to accomplish?

A. To halt human contributions to warming and limit the worst impacts of climate change, society must achieve a rapid decline in GHG emissions and ultimately achieve net-zero emissions. The Commonwealth's emissions limits aim to facilitate that rapid decline and

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12 EEA, *Determination of Statewide Greenhouse Gas Emissions Limits and Sector-Specific Sublimits for 2025 and 2030* (Jun. 30, 2022), https://www.mass.gov/doc/2025-and-2030-ghg-emissions-limit-letter-of-determination/download.

13 EEA, *Determination of Statewide Greenhouse Gas Emissions Limit and Sector-Specific Sublimits for 2050* (Dec. 22, 2022), https://www.mass.gov/doc/determination-letter-for-the-2050-cecp/download.

14 D.P.U. 20-80-B, Order, at 134.

ultimate outcome. The purpose of the sector-specific sublimits is to guide emissions reduction efforts across each sector, aiming to balance sectoral accountability, cost-effectiveness, and other factors based on the Commonwealth's energy transition research and stakeholder efforts.

Q. Please explain the Concept "Net-Zero Greenhouse Gas Emissions."

A. The Intergovernmental Panel on Climate Change ("IPCC"), in its 2021 Sixth Assessment Report, defined "net zero emissions as the condition in which metric-weighted anthropogenic GHG emissions are balanced by metric-weighted anthropogenic GHG removals over a specified period. The quantification of net-zero GHG emissions depends on the GHG emission metric chosen to compare emissions and removals of different gases, as well as the time horizon chosen for that metric."[15] The definition of "net zero" focuses on achieving a balance between the addition and removal of greenhouse gases, an approach intended to halt and prevent further increases in global warming.[16]

This definition also recognizes the need to reduce different types of GHGs. Carbon dioxide ("CO_2") and methane ("CH_4") are the two most impactful GHGs and have specific relevance to the regulation of the gas system. The term "metric-weighted" refers to the

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[15] IPCC, *Sixth Assessment Report, WGI, Climate Change 2022: The Physical Science Basis* Annex VII (Glossary), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_AnnexVII.pdf.

[16] This definition was officially published on Aug. 9, 2021, after the adoption of the Net Zero limit in G.L. c. 21N, § 3(b). However, this definition clarifies the language around emissions weighting from an earlier, and similar, IPCC definition published in the IPCC's *Special Report on the impacts of global warming of 1.5°C* (2018).

fact that different GHGs warm the atmosphere differently: An emission of CO_2 warms the atmosphere over a long time-horizon, while an emission of methane delivers an intense but temporary pulse of warming. The global warming potential ("GWP") is an example of a metric weight used to compare the impact of different gases, albeit imperfectly.

Q. What actions are needed to achieve net zero emissions while meeting the established interim limits and sublimits in Massachusetts? What is the basis for these actions?

A. In 2020, EEA published the 2050 Roadmap,[17] which evaluated various strategies to achieve net-zero greenhouse gas emissions. Generally, the 2050 Roadmap identified the following actions as necessary for decarbonization:

- Produce low-carbon electricity.[18]
- Improve energy and material use efficiency.[19]
- Electrify end uses.[20]
- Prioritize alternative fuels to hard-to-electrify sectors.[21]
- Limit the use of fossil fuel, while still allowing them for use in specific situations where they play a reliability and resiliency role and can leverage existing assets.[22]
- Expand the sharing of energy across time and space (e.g., transmission, storage, thermal networks).[23]

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17 EEA, *Massachusetts 2050 Decarbonization Roadmap* (Dec. 2020), https://www.mass.gov/info-details/ma-decarbonization-roadmap.

18 *Id.* at 55–59.

19 *Id.* at 37–37 (transportation); 48–49 (buildings).

20 *Id.* at 34–35, 38-42 (transportation); 44–47 (buildings).

21 *Id.* at 31–33; 50–53.

22 *Id.* at 60–61.

23 *Id.* at 55–66.

- Reduce non-CO_2 emissions (e.g., CH_4) in the context of the specific greenhouse gas and its source.[24]
- Promote responsible management of lands and ecosystems for the removal of carbon and limit emissions from land use change.[25]
- Balance residual fossil fuel use and other unavoidable emissions with carbon dioxide removal.[26]

These "pillars" of the 2050 Roadmap are consistent with work in other states, national-scale analyses such as Net Zero America,[27] the Fifth National Climate Assessment,[28] and the globally focused reviews conducted by the IPCC. Research indicates that achieving a net-zero emissions target requires significant, rapid decreases in fossil fuel consumption. However, the concept of net-zero emissions also acknowledges that certain, limited use of fossil fuels may persist, but would need to be offset by removals. Following the publication of the 2050 Roadmap and additional analyses and stakeholder engagement, EEA published the Clean Energy and Climate Plan for 2025 and 2030 ("2025/2030 CECP")[29,30] as well as

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[24] *Id.* at 68–71.

[25] *Id.* at 72–77.

[26] *Id.* at 78–80.

[27] Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final report*, PRINCETON UNIVERSITY (Oct. 29, 2021), https://netzeroamerica.princeton.edu/.

[28] Allison Crimmins, et al., *Fifth National Climate Assessment*, U.S. GLOBAL CHANGE RESEARCH PROGRAM (Nov. 14, 2023), https://toolkit.climate.gov/sites/default/files/2025-07/NCA5_2023_FullReport.pdf.

[29] EEA, *Clean Energy and Climate Plan for 2025 and 2030* (Jun. 2022), https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.

[30] EEA, *Appendices to the Clean Energy and Climate Plan for 2025 and 2030 ("Appendices to the 2025/2030 CECP")* (Jun. 2022), https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.

the Clean Energy and Climate Plan for 2050 ("2050 CECP")[31] to support the development of sector-specific sublimits for each target.

Q. What level of gas reduction is necessary to achieve the established limits?

A. Ultimately, to achieve the emissions goals, gas consumption needs to rapidly decline to a small fraction of what it is today. For example, electrification-oriented pathways in the Energy Pathways to Deep Decarbonization technical report ("Roadmap's Energy Pathways Report") and 2025/2030 CECP analysis consider compliant pathways that reduce gas use by 80 percent to 90 percent of current levels in the residential sector and 60 percent to 90 percent in the Commercial & Industrial ("C&I") sector.[32]

The sublimits for the residential and C&I sectors cover emissions from both pipeline utility gas and delivered fuels. While there is no specification of exactly how much gas needs to be reduced, achieving such reductions will necessitate a tremendous and focused effort to rapidly scale efficiency and electrification efforts that reduce gas consumption.

This reduction does not necessarily require the complete removal of pipeline or fossil gas from the state's energy portfolio. The 2050 Roadmap, along with other studies,[33] observe

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[31] EEA, *Clean Energy and Climate Plan for 2050* (Dec. 2022), https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050.

[32] Ryan Jones, et al., *Massachusetts 2050 Decarbonization Roadmap: Energy Pathways to Deep Decarbonization*, at 46 (2020) https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download; Appendices to the 2025/2030 CECP, at 13, 14.

[33] Energy and Environmental Economics and Energy Futures Initiative, *Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future* (Nov. 2020), https://energyfuturesinitiative.org/reports/net-zero-new-england/.

that gas-fired electricity generation can serve as a limited-use capacity resource that supports high levels of wind, solar, and other forms of renewable energy. Gas is still used for generation, but only during periods of limited clean energy supply, and at a level small enough to be offset by the removals allowed under the Commonwealth's net-zero target. The 2050 Roadmap further noted that there may be limited end uses in existing parts of the gas distribution system that may still align with net-zero emissions requirements.[34] The 2050 Roadmap's Energy Pathways Report also noted that future gas demand would be more optimally met using conventional natural gas, whose emissions can be offset by carbon removals, and not low-carbon gases that have exceptionally high costs.[35] This is discussed in detail in Section IV.

Q. What are the consequences of such reductions on the LDCs?

A. Appendix A to my testimony provides an in-depth review of climate-related disruptors to the investor-owned gas utility business model.[36] The LDCs' business model depends on economies of scale, as gas distribution systems are large, fixed costs that are: (1) spread

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[34] 2050 Roadmap, at 51 ("Indeed, even with the widespread deployment of heat pumps, gas-fired heat – whether blended with zero carbon gas or not – is expected to remain economically viable in certain locations and for a limited number of specific buildings or building types.").

[35] *Id*. at 86 ("[N]et-zero carbon fuels were used first for liquid fuels (versus gaseous fuels) because the avoided cost of refined fossil fuels is far higher than that of natural gas ($15-20/MMbtu vs. $3-5/MMbtu). For this reason, the Pipeline Gas pathway reached the 2050 emissions target by first decarbonizing all other liquid fuels before decarbonizing the pipeline, and then only to the degree required.").

[36] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. A. Appendix A discusses how the energy transition is disrupting the investor-owned gas utility business model and the consequences of this disruption.

over a large number of customers; (2) incurred to meet peak demand but have that cost spread across consumption throughout the year; (3) spread over the lifetime of the asset (50+ years).[37]

Three key climate-oriented disruptors challenge the ability for utilities to recover costs: (1) growing supply and distribution costs largely driven by the cost of repairing aging leak-prone pipe; (2) climate policy at all jurisdictional scales and voluntary action; and (3) competition from non-gas technologies.[38] The result of these disruptors is an increased likelihood of a policy- and market-driven reduction in gas use. Under current rate-making practices, utility costs would be concentrated on declining consumption and customers. Those who remain on the system will be those with the least ability to leave the system: specifically, renters and customers with limited access to capital needed to transition. These groups are likely to have lower incomes. While the current pace of building electrification is insufficient to meet the 2030 sectoral sublimits, between 2022 and 2024, nearly 30,000 heat pump installations were made in homes served by gas.[39]

Q. What is the role of the Department in enabling the achievement of the emissions limits and sublimits?

The 2021 *Act Creating A Next-Generation Roadmap For Massachusetts Climate Policy* ("Roadmap Act"),[40] which established the process for setting emissions sublimits, also

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37 *Id.* at 2.

38 *Id.* at 2.

39 *Id.* at 18–19.

40 St. 2021, c. 8.

established the following charge as a priority for the Department: "In discharging its responsibilities under this chapter and chapter 164, the 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 chapter 21N."[41,42] The Department's interpretation of its authority granted under G.L. c. 25 §1A was established in the D.P.U. 20-80-B order:

- Act "within our existing statutory authority, to discourage further expansion of the natural gas distribution system"[43]
- Apply "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,"[44]
- "[E]xplore opportunities for strategic and targeted decommissioning of portions of LDC service territories, through demonstration projects"[45]

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[41] G.L. c. 25, § 1A.

[42] While this authority is broad, it is bounded by statute and administrative exercise. For example, the MassDEP is granted statutory authority over emissions monitoring, tracking and regulation (G.L. c. 21N, §§ 2 and 3). The statutorily required climate planning process overseen by EEA has tasked MassDEP in the 2050 CECP with overseeing how emissions associated with the use and production of alternative fuels should be accounted for. Other agencies are given specific authority over enabling actions necessary to achieve the emissions limits. For example, DOER regulates the energy codes for new construction. (G.L. c. 143, § 94(o-r)). Several CCPs propose strategies that would engage the department in regulating alternative fuels and building energy codes. This would be unnecessarily redundant and inconsistent with current delegated authorities. This will be discussed later.

[43] D.P.U. 20-80-B, Order, at 14.

[44] *Id*. at 15.

[45] *Id*.

- Examine "innovative solutions to address the energy burden and affordability" in a separate proceeding.[46]

By emphasizing prudent oversight of future investments, the Department can help ensure that utility expenditures align with long-term decarbonization objectives and protect customers from unnecessary financial burdens.

B. <u>The Commonwealth is Unlikely to Meet the 2030 Sublimits, and at Risk of Missing the 2050 Sublimits, in Part Due to Gas Use.</u>

Q. Do the actions laid out in the CCPs meaningfully contribute to efforts to achieve the prescribed GHG emissions reductions sublimits set by EEA?

A. No. The plans convey the potential for modest *incremental* emissions reductions from several strategies that will be insufficient to meet the 2030 sublimit. The plans fail to outline a strategy for implementing the *systematic* changes required to align each LDC's business model with the 2030 and 2050 sublimits. While some elements of the plan exhibit alignment in direction, the pace of change is insufficient to achieve the limits and sublimits.

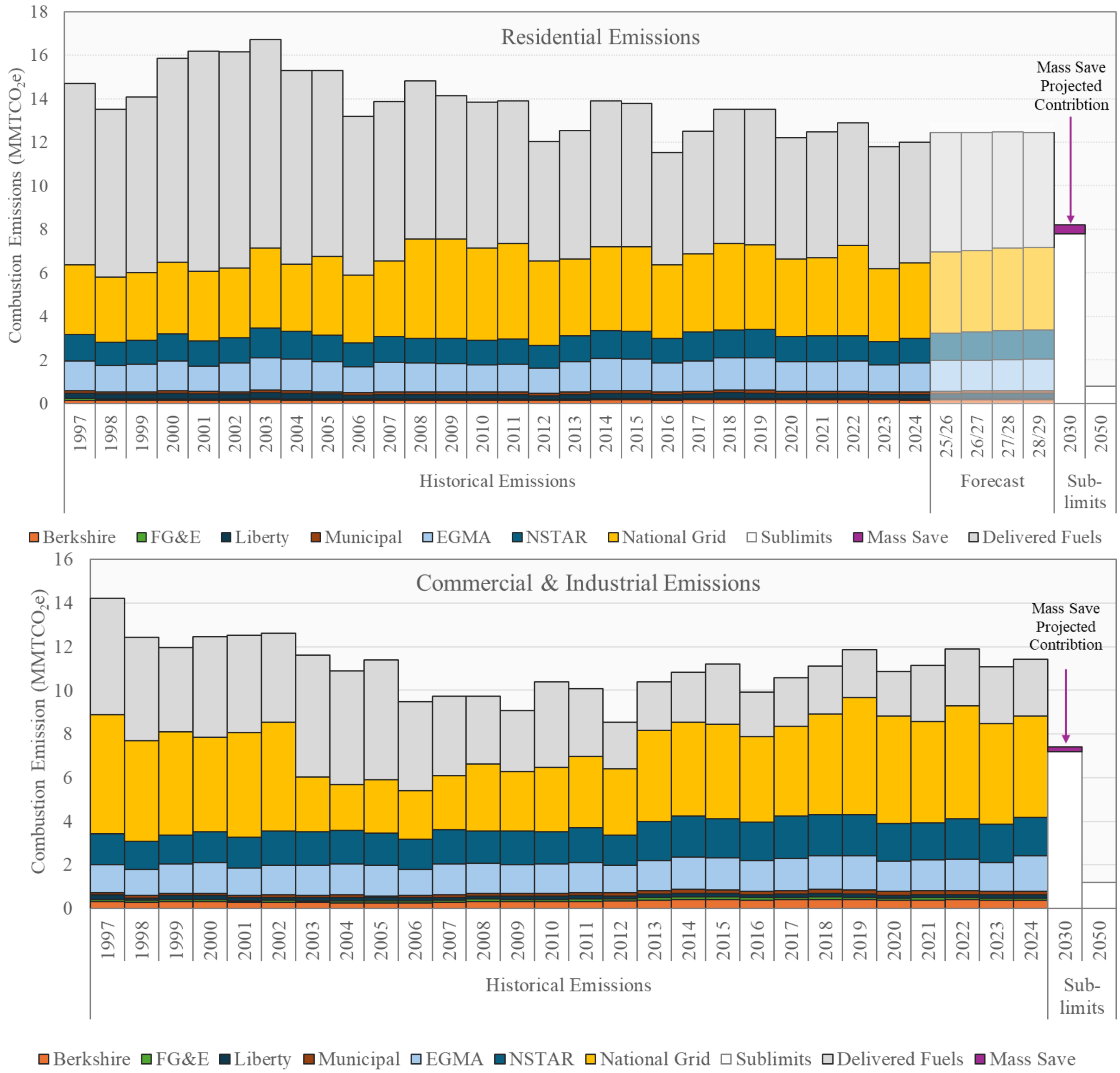
Q. How much does utility gas contribute to each sector's emissions, and are current sectors on track to achieve the emissions sector limits and sublimits?

A. Utility gas contributes significantly to emissions from both the residential and C&I sectors. As of 2023, gas combustion is responsible for approximately 51 percent of overall emissions in the residential sector and 76 percent of emissions in the C&I sector. Total emissions in both sectors currently exceed their 2030 sublimits by 50 percent (3.9 million metric tons of CO_2 ("$MMTCO_2$") and 47 percent (3.4 $MMTCO_2$), respectively. Figure 1

46 *Id*. at 16.

below shows historical and forecasted residential and building sector emissions by gas delivered for each LDC and from delivered fuels, along with the relevant sublimits. Although both sectors experienced declines in emissions from historical peaks, the trend has stagnated, with residential emissions forecasted by the gas LDCs to slightly rise over the remainder of this decade, making the 2030 sublimit even further out of reach:

Figure 1. Residential (top) and C&I (bottom) sector emissions for the Residential and Commercial Sectors.[47]



47 LDC data is extracted from EIA 176 fuel sales data due to incomplete responses to Exh. AG-Common-1-7 and inconsistent reporting. MassDEP inventory data for gas and other (oil, coal, LPG) are shown as grey bars. Differences between the Utility Gas MassDEP Inventory and aggregation of individual LDCs arise from variations in reporting across datasets. The forecast for Residential is derived from the most recent forecast and supply plans. Forecasts are excluded from the C&I figure as forecast and supply plans do not typically include non-firm sales forecasts.

The LDC forecast and supply plans consistently project steady increases in customer growth and demand that steadily increase consumption and emissions out to 2029—a period in which consumption needs to decline to meet the sublimits.

Q. Do the LDCs have responsibility for meeting the Commonwealth's GHG emissions sublimits?

A. Yes. Achieving the Commonwealth's emissions sublimits is a statutory obligation that is not discretionary. While emissions are ultimately induced by customer utilization of gas, the LDCs are: (1) exposed to growing energy transition risk associated with policy and market-driven changes in gas demand; (2) uniquely positioned to influence system-wide emissions through infrastructure decisions, changes in service practices, messaging to customers and strategic planning; and (3) ultimately subject to the legislatively-established priorities for the Department discussed above that requires balancing reductions in GHG emissions with other goals.

The CCPs do not reflect a sufficient effort to address energy transition risk and drive forward the necessary system changes in a manner that comports with the Department's priorities or the Commonwealth's emissions limits. Furthermore, the LDCs are directly responsible for shaping consumer perspectives on gas, which impacts customer participation in achieving the sublimits. Despite electrification emerging as the foundational strategy for building decarbonization by 2021, the LDCs continue to promote utility gas as a climate-aligned alternative in their efforts to continue customer growth and advocate for low-carbon fuels. However, the continued promotion of these strategies—

over the past several years and through these CCPs—has both increased the gap between projected 2030 emissions and the required sublimits, and has increased the risk that the 2050 limits will not be achieved.

Q. How should the Department weigh efforts to achieve building sector sublimits (Scope 3) against those needed to achieve the natural gas system sublimits (Scope 1)?

The Department should prioritize efforts to reduce building sector emissions (Scope 3) while pursuing methane mitigation (Scope 1) in a manner that is informed by improved measurement and integrated with broader system planning. Building sector emissions from gas combustion represent the overwhelming majority of gas system emissions and must be the primary focus of climate compliance efforts. Where large leaks can be confidently identified and cost-effectively addressed, such actions deliver meaningful near-term benefits for the climate. The Department should encourage the LDCs to develop improved leak detection and measurement capabilities to support strategic, cost-effective mitigation. Methane mitigation efforts must be pursued in the context of comprehensive system planning that acknowledges the need for significant reductions in gas consumption. Prioritizing pipe replacement investments in areas where the gas system will continue to operate while deferring such investments in areas more suitable for electrification and eventual decommissioning represents a more prudent approach than a blanket program of leak-prone pipe elimination. The goal should be to avoid stranded costs while achieving the Commonwealth's emissions limits across all sectors.

Q. Should the LDCs continue to prioritize leak-prone pipe replacement as a GHG emissions reduction strategy?

A. No. Remediating gas leaks without reducing gas usage is not an effective climate compliance strategy and will result in only nominal reductions in GHG emissions. In Appendix B, Section D of my testimony, I present a pipeline replacement scenario analysis to compare the climate impact of various scenarios for pipe replacement and building electrification.[48] This analysis shows that, while methane leaking from a pipe segment can have a significant climate impact, CO_2 emissions are a much greater concern. From the perspective of GHG mitigation, pipe replacement represents a costly strategy for nominal GHG emissions reductions. Targeted electrification, on the other hand, eliminates both methane emissions from the leaking pipe and CO_2 emissions from customer use.

Q. Do the LDCs propose adequate metrics to measure and report GHG emissions reductions in the CCPs?

A. No. The D.P.U. 20-80-B Order requires the LDCs to show how they "contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1 and Scope 3 emissions."[49] The LDCs' jointly proposed reporting metrics in the CCPs do not adequately measure Scope 3 or Scope 1 emissions reductions. First, the LDCs do not propose a reporting metric for Scope 3 emissions. Second, although the LDCs propose a reporting metric for Scope 1 emissions (i.e., Reporting Metric 3),[50] as discussed below, this proposal

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48 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B, at 30–35.

49 D.P.U. 20-80-B, Order, at 135.

50 *See Berkshire*, D.P.U. 25-40, Exh. BGC-CCP, at 50 ("Berkshire will report against the 2024 target until DEP updates targets for it in future years."); *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 104; *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 62; *Liberty*, D.P.U. 25-43, Exh. LU-CCP, at 48; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 199.

does not adequately measure methane emissions and is not representative of the LDCs' actual total contributions to GHG emissions sublimits. In the following sections, I recommend reporting metrics for both Scope 3 (residential and C&I) and Scope 1 (methane for gas distribution system) GHG emissions.[51]

1. Residential and C&I Emissions (Scope 3)

Q. What is your proposed Reporting Metric with respect to residential and C&I (Scope 3) emissions?

A. On an annual basis,[52] I recommend that the Department require LDCs to report fuel deliveries and subsequent combustion emissions in a manner that is consistent with the Massachusetts Department of Environmental Protection's ("MassDEP") GHG Emissions Inventory.[53] This inventory is constructed from consumption data reported by the LDCs through Form 176 to the U.S. Energy Information Agency ("EIA"). The EIA aggregates this information in its State Energy Data Systems ("SEDS"), which is then used by the

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51 In Exh. AG-RIF-PV-1, expert witnesses Reihaneh Irani-Famili and Pamela A. Viapiano review the LDCs' jointly proposed Reporting Metrics and propose enhancements and additional metrics. My testimony regarding metrics focuses exclusively on GHG emissions reporting metrics.

52 *See id.* The experts recommend annual reporting for all metrics. I agree annual reporting of metrics is key to ensuring climate compliance.

53 *See* MassDEP Emissions Inventories: Greenhouse Gas Baseline & Inventory, App. C, https://www.mass.gov/lists/massdep-emissions-inventories.

EPA's State Inventory and Projection Tool to generate gas use data for the MassDEP GHG Inventory.[54]

I recommend that the LDCs use the same data submitted on EIA 176. This will ensure consistency with the data underlying the State's GHG inventory and its breakdown by sectors. Table 2 below provides an example format with guidance on the reported data. For customer counts and volumes, the data for both direct sales and transportation customers should be summed.

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[54] The LDC's Annual Return filings also report annual consumption data. Some of these filings include informative breakdowns by rate class. However, the LDCs are inconsistent with their reporting of transportation customers across residential and commercial rate classes. Further, sales to electric generators are grouped with sales to C&I customers. Since electric sector customers are subject to separate emissions limits, this data set would require additional changes and retroactive reporting by the LDCs to be of use. *See, e.g.,* Boston Gas 2023 Annual Return, which reports direct but not transportation deliveries on page 43, yet provides detailed rate class deliveries to direct customers (on page 44) and transportation customers (on page 44a); EGMA 2023 Annual Return, which reports direct and transportation deliveries on page 43, detailed rate class deliveries for direct sales only on page 44; Liberty 2023 Annual Return, which only reports direct deliveries on page 43. Direct and transportation send-outs are reported on page 72, but without sector details. https://www.mass.gov/info-details/find-a-natural-gas-company-annual-return.

Table 2. Example reporting table for a Reporting Metric for Scope 3 Emissions. "Item" refers to EIA Form 176 response line item.

Sector	Report Period	Number of Customers	Volume (Mcf)	Heat content of gas delivered to consumers (Btu/cf)	Emissions	Average Gas Use per Customer
Residential	20 _ _	(Item 10.1, Customers)	(Item 10.1, Volume)	(Item 9)	See calculation	Volume / customers
Residential (Transport)	20 _ _	(Item 11.1, Customers)	(Item 11.1, Volume)	(Item 9)	See calculation	Volume / customers
Commercial	20 _ _	(Item 10.2, Customers)	(Items 1 10.2, Volume)	(Item 9)	See calculation	Volume / customers
Commercial (Transport)	20 _ _	(Item 11.2, Customers)	(Item 11.2, Volume)	(Item 9)	See calculation	Volume / customers
Industrial	20 _ _	(Item 10.3, Customers)	(Item 10.3, Volume)	(Item 9)	See calculation	Volume / customers
Industrial (Transport)	20 _ _	(Item 11.3, Customers)	(Item 11.3, Volume)	(Item 9)	See calculation	Volume / customers

The LDCs should calculate emissions using the following formula:

*Emissions by Sector (tCO2) = Volume (Mcf) * Heat Content Factor (Btu/cf) * 0.000001 (MMBtu/Btu) * 1,000 (cf/Mcf) * Natural Gas Emissions Factor (kg CO_2 / MMBtu) * 0.001 (tCO_2 / kg CO_2)*

For the Natural Gas Emissions Factor, the LDCs should use the most recent value used by the EPA for Natural Gas as posted on the EPA Emissions Factor Hub (currently 53.06 kg CO_2 per MMBtu).[55]

2. Methane Emissions from Gas Distribution System (Scope 1)

Q. How significant are methane emissions compared to economy-wide emissions and all gas-system emissions?

[55] EPA, *Emissions Factor Hub*, https://www.epa.gov/climateleadership/ghg-emission-factors-hub.

A. Estimated methane emissions from the gas system are a relatively small component of economy-wide emissions (1.1 percent) and of all gas system emissions (4.4 percent). Appendix B to my testimony provides background context on methane emissions and measurement.[56] First, it explains that methane is a short-lived but potent GHG. Where methane can be *confidently* mitigated, methane mitigation delivers a significant reduction in warming; however, prioritizing it relative to CO_2 incurs notable but overlooked tradeoffs between near-term and long-term warming.[57] Second, it discusses how methane escapes from the gas system.[58] Finally, it reviews the current practice for estimating these emissions in the State's GHG Inventory, and MassDEP's regulation of mains and services (310 CMR 7.73).[59]

Q. How do the CCPs propose to achieve climate compliance with respect to Natural Gas Distribution Services (or Scope 1) Emissions?

A. Generally, the CCPs make several references to their ongoing efforts to reduce methane emissions through the elimination of leak-prone pipes ("LPP"). The plans describe the ongoing gas system enhancement ("GSEP") program as the primary mechanism for

56 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B. Appendix B discusses methane emissions and the limitations of gas pipe replacement in achieving climate compliance.

57 *Id.* at 21–23.

58 *Id.* at 23.

59 *Id.* at 23–27. Promulgated in March 2021, 310 CMR 7.73, requires each LDC with a GSEP order from the Department to annually report emissions from the total miles of mains and service pipelines by material type, and to report the total miles of mains and service pipelines by material type and age.

eliminating leak-prone pipes, but some observe that adopting non-pipeline alternatives ("NPAs") and targeted electrification can also support this objective. The CCPs also describe how emissions are regulated via: (1) the GSEP statute,[60] which broadly directs the remediation of leak-prone pipe: and, (2) the regulation of emissions by DEP, which directly regulates emissions, but through pipe-length and pipe-material estimates for fugitive methane emissions that serve as a de facto regulation on pipe material. Notably, Unitil discusses efforts to implement Advanced Mobile Leak Detection ("AMLD") as an "industry-leading approach," while Berkshire expresses its interest in future AMLD assessments. As discussed below, the LDCs suggest using a metric, "Emissions from Mains and Services," based on their reporting requirements to DEP, to demonstrate progress on climate compliance.

Q. Do current methane accounting practices accurately estimate the amount of methane released from individual gas distribution assets?

No. The emission factors used by MassDEP (in both the inventory and 310 CMR 7.73) represent average emissions across distribution assets, not individual emissions from a component of the system.[61] This methodology differs from accounting emissions based on gas consumption, which relies on metered data and well-understood, well-quantified emissions associated with combustion. Leaks occur irregularly throughout the system and

[60] G.L. c. 164, §145.

[61] A detailed discussion of MassDEP's selection of emissions factors is available at 310 CMR 7.73: Technical Support Document (Dec. 2020), https://www.mass.gov/doc/310-cmr-773-technical-support-document-tsd/download.

can vary widely in size. Quantification of fugitive methane has far less confidence than that of CO_2 emissions from consumed gas, where the release of CO_2 is an accurately measurable property of metered gas combustion. Several studies have attempted to use various sampling methodologies to establish emissions factors that could be applied to inventories of pipe (in terms of miles of main or count of services). These studies consistently indicate that older pipes made from materials like cast iron exhibit higher average leak rates compared to newer plastic pipes. However, it is important to note that leak rates can vary widely within each category. While some cast iron pipes may emit relatively low amounts of methane, others can be significant sources of fugitive emissions.

To illustrate the point, a 2016 study of Boston-area methane leaks demonstrated significant variability in leak sizes.[62] Of the leaks identified in this study, the top 20 percent of leaks were responsible for 75 percent of the emissions, the top 6 percent of the leaks were responsible for 50 percent of the emissions, and the largest leak was responsible for 25 percent of the emissions. This diversity has consequences for mitigation. A leak-prone pipe can be leaky or not based on the conditions that led to its deterioration. Consider a cast iron pipe (classified as leak-prone) that has a large leak, and one that does not leak. Both have the same inventoried emissions based on the current factor approach. Because methane's impact is large but temporary compared to CO_2,[63] replacing the non-leaky pipe

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[62] Margaret F. Hendrick, et al., *Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments*, ENVIRONMENTAL POLLUTION (Jun. 2016), https://doi.org/10.1016/j.envpol.2016.01.094.

[63] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B, at 21–23.

has no material impact on actual emissions. Pipe replacements are simply a roll of the dice—albeit a dice weighted by material type—in terms of how much methane they mitigate.

The standard emissions factors also fail to capture the impact of efforts other than pipe replacement. These efforts include direct leak repair or patching, as well as advanced approaches such as relining or CISBOT[64] sealing practices, which can significantly reduce methane emissions while maintaining the pipe's material classification. While such actions reduce methane emissions, the Commonwealth’s inventory and 310 CMR 7.73 do not account for these reductions. Atmospheric methane measurements in the Boston urban region corroborate this. A 2021 study found that both total methane emissions were higher than those estimated by the Commonwealth’s inventories but also showed no observable reduction in methane during the first six years of GSEPs.[65]

Q. Do the Companies acknowledge inaccuracies in such emissions factors?

A. Generally, no. Exh. AG-Common-1-4 asked each LDC if the standard emissions factors were accurate.[66] Berkshire did not adequately respond. Liberty, Eversource, and National Grid referred to state and federal code for the setting of emissions factors but did not opine

64 CISBOT is a robotic system that enters live, large diameter cast iron gas main to internally remediate leaks and prevent new leaks from forming by injecting a sealant into the joint material.

65 M.R. Sargent, et. al, *Majority of US urban natural gas emissions unaccounted for in inventories*, PROC. NATL. ACAD. SCI. U.S.A., at 44 (2021), https://doi.org/10.1073/pnas.2105804118.

66 *See, e.g.*, *Eversource*, D.P.U. 25-44/45, Exh. AG-Common-1-4.

on the accuracy of such factors. Only Eversource noted that it considered alternative factors for estimating emissions. However, Eversource determined that standard emissions factors were "the best available option for estimating fugitive emissions from the distribution system."[67] Unitil referenced the fact that the advanced mobile leak detection survey observed fewer emissions than what the factors would estimate.[68]

Q. The LDCs propose a metric for demonstrating climate compliance—Emissions from Mains and Services based on their reporting requirement for 310 CMR 7.73. Is this an appropriate metric?

No, this proposed metric is not appropriate because it does not adequately measure methane emissions, and it is not representative of the LDCs' actual total contributions to GHG emissions. The 310 CMR 7.73 metric is based solely on the pipe's material, and not on other factors that may influence methane emissions from the pipe. Such factors include contextual drivers (age and soil conditions), as well as the application of non-replacement mitigation strategies like short-term patching or long-term pipeline relining. Because the 310 CMR 7.73 metric is solely based on pipe material, it biases long-term planning in favor of pipe replacement strategies. Policy and planning efforts should move away from such pipe (per-foot/mile)-based activity factors for designing leak reduction strategies and towards targeted identification of leaks.

Q. What is your proposed Reporting Metric with respect to methane emissions from the gas distribution system (Scope 1)?

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67 *Eversource*, D.P.U. 25-44/45, Exh. AG-Common-1-5.

68 *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 31–32.

A. To effectively measure methane emissions, I recommend that the Department require the LDCs to: (1) submit annual leak reports, and (2) conduct an AMLD study, like the one conducted by Unitil and being explored by Berkshire. Annual leak reports should include the following information:

- Annual reporting of miles of pipe and service counts by material, and associated emissions, as required by 310 CMR 7.73, and PHMSA reporting requirements
- An Excel spreadsheet or delimited text file of open leaks reported in each year's service quality report pursuant to 220 CMR 114.08 that includes latitude and longitude for each leak.[69]
- An Excel spreadsheet or delimited text file of repaired leaks reported in each year's service quality report pursuant to 220 CMR 114.08 that includes latitude and longitude for each leak.
- A summary table of leak repairs by material type.

The Department should also encourage the LDCs to conduct AMLD studies and novel methane measurement methods. Such methods, as well as probability distributions underlying emissions calculations, should be transparent and should generate a summary of emissions that corresponds with 310 CMR 7.73 reporting requirements. The result of these methods should demonstrate asset-level and zonal (or gridded) tracking of leaks, provide descriptive metrics on leak density and emissions density at those scales, and serve as a baseline for ongoing monitoring.

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69 Addresses are included in each company's service quality report. HEET has geocoded such data previously: https://www.heet.org/gas-leaks-map.

III. NEW CUSTOMER CONNECTIONS

A. <u>Massachusetts Policies and Regulations are Designed to Limit and Discourage New Customer Connections.</u>

Q. What are the key policies impacting new customer connections in Massachusetts?

A. Massachusetts has various policies affecting new gas customer connections:

- Municipal opt-in Stretch and Specialized building energy codes that are more stringent than the Base Code;
- A pilot fossil fuel-free code implemented in 10 municipalities;
- Mass Save incentives for high-performance and electric construction; and
- Customer education.

Q. What are the Base, Stretch, and Specialized codes?

A. Massachusetts enforces a three-tier building energy code—Base, Stretch, and Specialized Codes. These set performance standards for new construction and major renovations. The latest code took effect on October 11, 2024.

The Base Code largely follows the International Energy Conservation Code ("IECC") and applies to all communities. Notably, the 2024 update raised minimum gas furnace efficiency ratings from 80 percent to over 95 percent annual fuel utilization efficiency.

The Stretch Code and Specialized Code are increasingly stringent tiers of codes that municipalities can opt into. Participation in one of these code tiers is necessary for a municipality to receive a "Green Community" designation and to be eligible for grants and technical assistance from the state. The Stretch code was established in 2008 as part of the

Green Communities Act and was updated with the 2024 edition.[70] The Specialized Code was incorporated into the 2024 edition of the code due to the Climate Roadmap Act of 2021, which required the Department of Energy Resources ("DOER") to develop a tier aligned with the Commonwealth's emissions limits and sublimits.[71]

The code specifies different standards for different building classes (e.g., residential and commercial) and different projects (new construction, accessory dwelling units, major alterations or additions). Different building types have different code requirements. Generally, in the residential sector, buildings are required to achieve a specified Home Energy Rating Systems ("HERS") score. Lower HERS scores indicate higher performance—more efficient buildings. Buildings designed to be all-electric are allowed a higher HERS score, while those that still rely on fossil fuels require a lower, more stringent HERS score and take additional steps to make their buildings more efficient. This incentivizes projects to go fully electric. Measures that target embodied carbon in construction may earn additional points, permitting a higher HERS score. Table 3 below illustrates the differences in requirements between the Stretch and Specialized Codes for all-electric and fossil-fuel construction.

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[70] St. 2008, c. 298 (codified at G.L. c. 21N).

[71] St. 2021, c. 8 (codified at G.L. c. 21N, §§ 3, 3A, and 4).

Table 3. Summary of the Residential Stretch and Opt-in Codes.

<table>
<tr><th></th><th>All-Electric</th><th>Fossil Fuel</th></tr>
<tr><td rowspan="2">Stretch</td><td>Home Energy Rating Score (HERS) of 45 or Lower</td><td>Home Energy Rating Score (HERS) of 42 or Lower</td></tr>
<tr><td colspan="2">Prewired for EV Charging
Energy recovery ventilation</td></tr>
<tr><td>Specialized</td><td>• HERS rating of 45 or lower (same as above)</td><td>• HERS rating of 42 or lower (same as above)
• Prewiring in place for future electric heating and appliances
• On-site solar (when feasible)
• Net zero energy (HERS 0) or Passive house certification for new homes over 4,000 ft^2
• Passive house certification for multi-family buildings over 12,000 ft^2</td></tr>
</table>

All buildings in these opt-in tiers must be pre-wired for EV charging. Fossil-fuel buildings under the Specialized code also need to be prewired for electric heating and appliances and to have on-site solar when feasible. Similar requirements apply to commercial buildings. 247 municipalities (housing 60.9 percent of the state's population) have adopted the high-performance Stretch code, while 55 municipalities (housing 31.5 percent of the state's population) have adopted the new Specialized code.[72]

Q. What is the Fossil Fuel Free Demonstration Program?

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

A. The Municipal Fossil Fuel Free Building Demonstration Program is legislatively authorized,[73] and administered by DOER under 225 CMR 24.00.[74] It allows up to 10 municipalities to adopt requirements for new construction and major renovation projects to be fossil-fuel-free. Table 4 below lists the 10 communities participating in this program and their utility providers.

Table 4. Electric and Gas Providers for the DOER Municipal Fossil Fuel Free Building Demonstration Program

Town	Electric Provider	Gas Provider
Acton	Eversource	National Grid
Aquinnah	Eversource	None
Arlington	Eversource	National Grid
Brookline	Eversource	National Grid
Cambridge	Eversource	Eversource
Concord	Municipal	National Grid
Lexington	Eversource	National Grid
Lincoln	Eversource	National Grid
Newton	Eversource	National Grid
Northampton	National Grid	Berkshire

Q. How does the Three-Year Energy Efficiency Plan impact new customer connections?

A. The Massachusetts Three-Year Energy Efficiency Plan for 2025 through 2027 ("Three-Year Plan") offers specific incentives for new construction based on specific criteria.[75] For

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[73] *An Act Driving Clean Energy and Offshore Wind* (St. 2022, c. 179, § 84).

[74] 225 CMR 24.00 establishes the framework, requirements, and timeline for cities and towns to participate in the Department's Municipal Fossil Fuel Free Building Construction and Renovation Demonstration Project as authorized by St. 2022, c. 179, § 84.

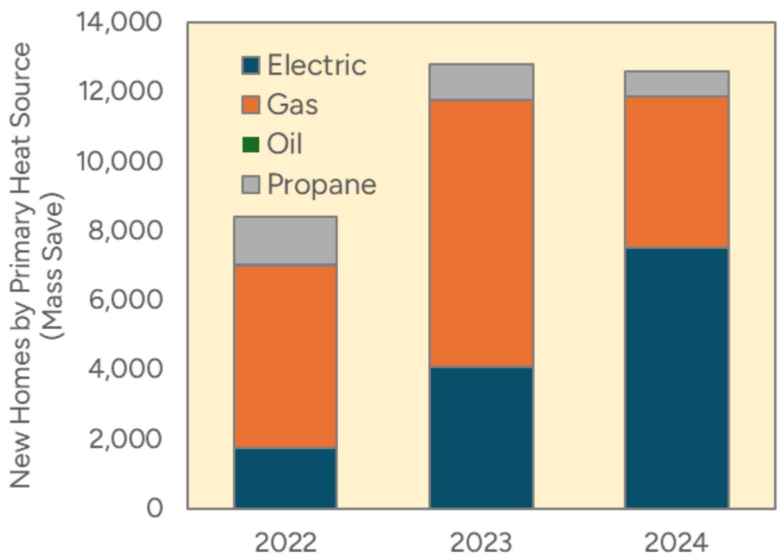
[75] *2025–2027 Three-Year Energy Efficiency Plans*, D.P.U. 24-140 through D.P.U. 24-149, (Oct. 31, 2024), https://www.masssave.com/-/media/Files/PDFs/Mass-2025-2027-Energy-Efficiency-Decarbonization-Plan.pdf.

example, single-family homes can receive a $7,500 credit for meeting the HERS 45 standard set by the Stretch code and adopting all-electric appliances. The home can receive additional incentives for induction cooktops ($250), ground-source heat pumps ($9,000 max), various levels of embodied carbon reductions, and other measures. There are substantial incentives for homes that meet Energy Star Next Gen or Passive House Standards ($25,000). Commercial incentives include technical assistance in design, electric equipment incentives based on system size, and performance incentives based on square footage. The 2025-2027 Three-Year Plan phases out incentives for fossil fuel equipment except for a limited number of low-income situations. The 2025-2027 Three-year Plan also phased out incentives for high-efficiency gas or fossil fuel equipment, except in a limited number of circumstances.

During the 2022-2024 Three-Year Plan, the share of new electric construction of homes receiving rebates steadily grew to be the majority of homes by 2024 (Figure 2 below). While this data does not track homes that did not receive Mass Save® data, 14,490 new private housing unit permits were issued in 2024.[76] Over this time, the number of gas homes receiving incentives has declined.

[76] U.S. Census Bureau, *New Private Housing Units Authorized by Building Permits for Massachusetts* (Sept. 24, 2024), https://fred.stlouisfed.org/series/MABPPRIV.

Figure 2. New residential homes that received Mass Save incentives during the 2022-2024 planning cycle.[77]



Q. What information are LDCs required to provide to prospective customers seeking to connect to the gas distribution system?

A. The Department, in Order 20-80-B, prohibited the inclusion of marketing costs in rates.[78] Before connecting a new customer, the LDCs now provide customers with information about alternatives to gas and require customers to sign an attestation form acknowledging that they have been made aware of such alternatives.

B. The Department Should Adopt the Proposed Line Extension Allowance Policy in Interlocutory Order D.P.U. 20-80-E.

Q. What is a line extension allowance?

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[77] Energy Efficiency Advisory Council, *2024 Fourth Quarter Program Administrators KPI*, https://ma-eeac.org/wp-content/uploads/2024-Q4-KPI-EWG-Reporting-3-13-255361632.xlsx.

[78] D.P.U. 20-80-B, Order, at 56–57.

A. A line extension allowance ("LEA" or "allowance") is a utility's financial contribution to cover some or all costs associated with extending gas service to new customers. The size of an allowance is informed by anticipated revenues based on customer usage. LEAs have been allowed and even encouraged under the prior assumption that expanding the gas system with more customers and utilization will lower average costs in the long run. This assumption, however, no longer holds true.

An LEA includes the capital invested by the LDC to connect the new customer to the system. The addition of this capital to the rate base increases the revenue requirement for all customers; however, a central principle in establishing LEAs is that existing customers should not subsidize new customers. The allowance is structured based on the expectation that the initial years of customer revenue will repay its value. Allowances are determined such that expected future revenues over a specific time horizon will result in a net present value of zero for existing customers. After that period, it is assumed that the new customer lowers the average cost of the system for existing customers. As discussed below, the uncertainty around expected future revenues challenges the premise that LEAs will be recovered from the customers that incur them.

Q. What is a contribution in aid of construction ("CIAC")?

A. A CIAC represents the remaining connection cost that must be paid upfront by the customer if allowances are insufficient to cover the full cost.

Q. Do line extension allowances promote the expansion of the gas distribution system?

A. Yes. Line extensions promote expansion of the gas system by lowering the upfront cost for new customers to connect to gas. For a typical residential home, this can be a few thousand dollars, which may amount to a small part (roughly less than or around one percent) of the total construction cost or a considerable amount of the cost of converting from delivered fuels to gas. This makes the life cycle cost of gas more appealing than delivered fuel or electric alternatives. The portion of the allowance covering the construction is capitalized by the utility, whereas the customer's CIAC is not. The utility's investors earn a rate of return on the capitalized allowance. The return is guaranteed as the allowance is rate-based. Even if the new customer does not use as much gas as expected, existing customers would ultimately be responsible for the costs. As such, LEAs incentivize the utility to expand the system.

A core principle of cost allocation is the use of accurate price signals to *incite* customers to select options that align with the objectives of cost allocation. The LDCs contend that eliminating LEAs will disincentivize customers from choosing gas, noting that "increasing CIAC costs were proving to be insurmountable barriers to customers."[79]

An allowance is no different than a Mass Save rebate, as they both are "incentives" that shape customer behavior. The latter, like the CIAC policy, is a cost-allocation mechanism determined by an analytical process that seeks to balance the Department's regulatory priorities. Both are informed by formal calculations that rely on assumptions. While not

[79] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 22.

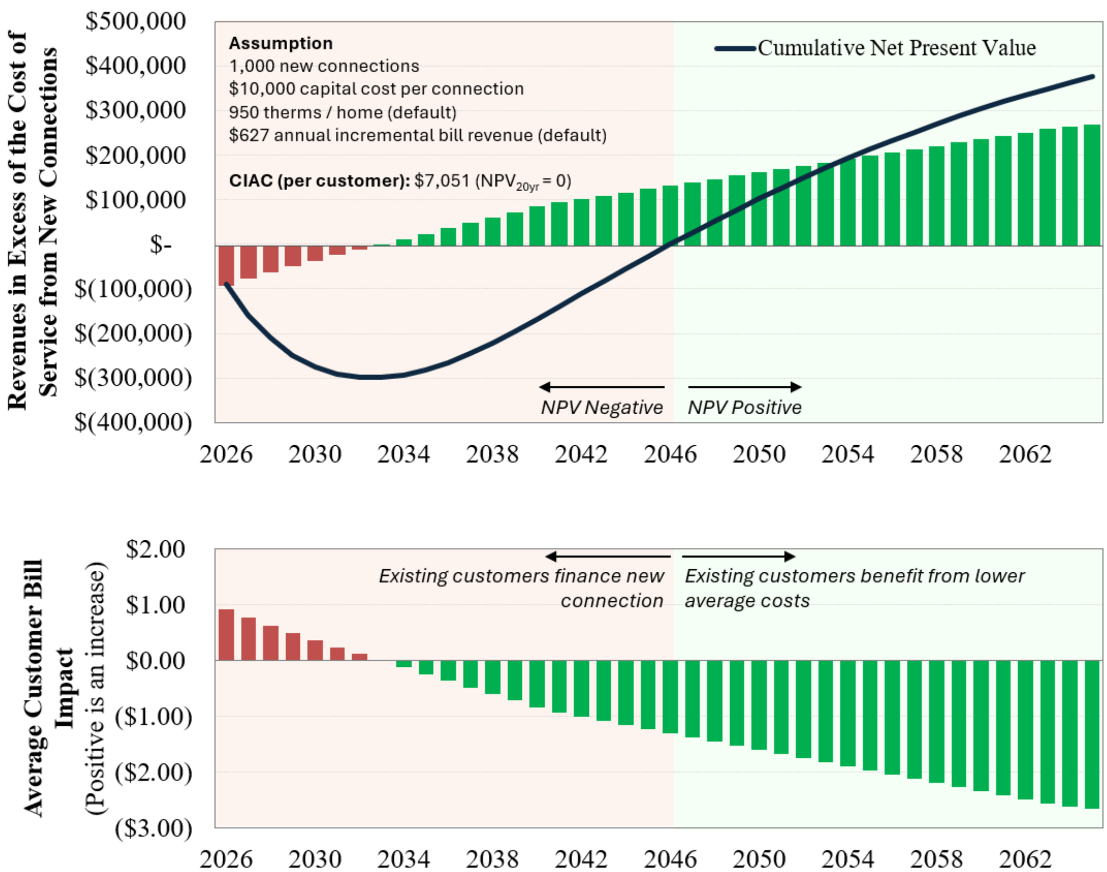
perfect, these methods should be just and reasonable in how they implement price signals, and they should also be adaptable to new information and the balancing of Department priorities.

The current allowance policy is not a neutral midpoint or null price signal, but rather a collection of practices that lower the barrier to entry, based on assumptions that are generous to new customers while reflecting reasonable and prudent principles of cost causation from an era with different energy priorities. The long payback periods used to calculate CIACs, for example, reflect the fact that there was once a broad consensus that the gas system was expected to grow in perpetuity. Now, it is reasonable to reconsider such assumptions to balance the risk of existing customers financing the addition of new customers to *incite* growth. These payback periods, which are exceptionally long in consumer energy services, include future years marked by increasing uncertainty about the competitive landscape for gas and increasing consumer alternatives.

Q. How are LEAs calculated, and what is the impact on customers?

A. Allowances are costs socialized across the rate base, under the assumption that, after an allowance is recovered through a new customer's contributions, that customer lowers the average cost of the system. Figure 3 below illustrates this.

Figure 3. Illustration of how an annual cohort of line extension allowances impact existing customers.[80]



The bars in the top figure show the revenue in excess of the cost of service associated with new connections. A positive value indicates the new customers are contributing more to the system than it costs, whereas a negative value indicates their incremental costs are

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[80] This data was produced using Liberty Utility's CIAC Calculator Model with modifications and using an illustrative scenario. *See Future of Gas*, D.P.U. 20-80, Exh. Liberty-2. Modifications removed mid-year adjustment for first and last year as well as extended the analytical window from 20 to 40 years. Average customer bill impacts are calculated from the cost-of-service impacts, assuming that the 1,000 customers are added to a utility with 100,000 customers (a historically typical 1 percent growth rate).

higher than their contributions. Revenues are calculated from the customer rate (fixed charge) and the distribution rate times gas usage. Cost of service is calculated from operations and maintenance, depreciation, taxes, and the return requirement (based on the LDC's weighted average cost of capital).

The bars in the bottom figure illustrate how this cost is allocated to existing ratepayers in their bills. A $10 million investment by a utility serving 101,000 customers and financed over 20 years, results in an average ~$1 increase in bills in the first year.

In this example, an average construction cost of $10,000 per customer requires a CIAC of $7,051. The LEA includes the difference between the CIAC and construction cost, as well as taxes and incremental operating expenses incurred as the allowance is "paid back," a total value that is greater than the total capital cost. Over the first seven years, the increased annual cost of service is greater than revenues and leads to net bill increases for existing customers. The allowance is recovered on a 20-year net present value basis. It thus requires 13 additional years of revenue from new customers to pay back the 7-year period of higher bills for existing customers. After this time, the contribution of new customers becomes net beneficial to existing customers by lowering average costs across the system.

This example shows the impact of a single year of allowances. Under a growing system, new customers are continuously being added. At the same time, earlier additions are being paid off and begin to be a net benefit to earlier customers. If future revenues are sufficiently robust and the calculation of allowances reflects that, growth should be mutually beneficial.

However, if future revenues are less than expected, this no longer holds, and existing customers bear the burden of new infrastructure.

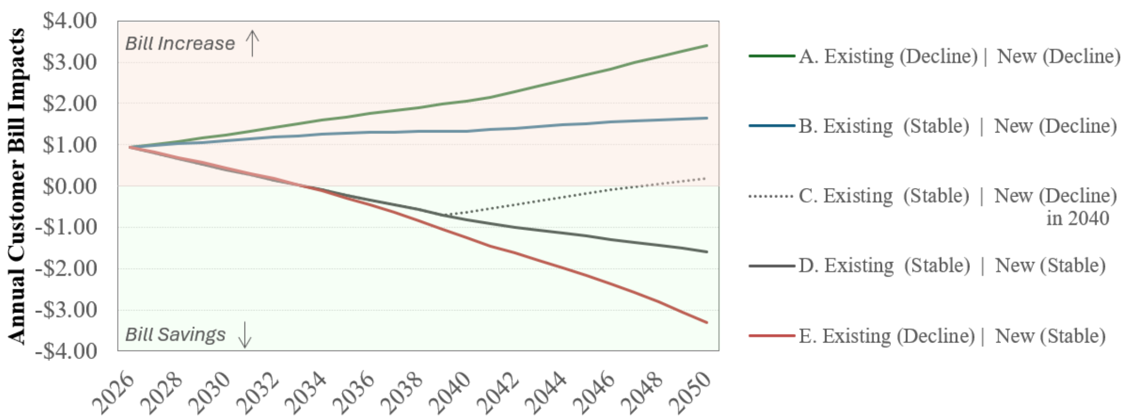
Q. Do existing customers subsidize the cost of line extension allowances for new customers?

Increasingly, yes, because of the risks associated with new customers. The industry often contends that allowances are not a subsidy from existing customers, as the allowance is calculated on the assumption that it has a net present value of zero to the gas system. This assumption holds if growth continues and demand does not decrease. It is also premised on the LDC's value-based assumption, on behalf of its customers, that this investment and payback are net beneficial to the customers (e.g., an existing customer may prefer not to finance growth of the gas system given their perception of present costs versus future benefits).

Customer revenue from the gas system has historically grown steadily, but emerging risks now threaten this trend. Technology substitution, such as electrification driven by market or policy shifts, poses a significant risk to future customer use of the gas system. This changes how the models underlying the LEA and CIAC calculations need to be understood.

Figure 4 below forecasts bill impacts from the addition of 1,000 new customers to a customer base of 100,000, with various scenarios for the decline of existing customer counts (3 percent of the previous year) and decline of new customers' revenue (3 percent of the previous year).

Figure 4. Forecasted bill impacts from the addition of 1,000 new customers to a customer base of 100,000, with various scenarios for the decline of existing customer counts (3 percent of the previous year) and decline of new customers' revenue (3 percent of previous year).



As illustrated in Figure 4:

- The solid black line (D) represents a trajectory where near-term existing customer bill increases are "paid back" by longer-term reductions in the average cost reaching a net present value of zero in 2046 based on the 20-year payback requirement.
- The red line (E) depicts what happens under a steady decline of existing customers.
- The green (A) and blue (B) scenarios depict declining and stable existing customers, respectively, under a decline in new customers. All non-migrating existing customers experience an ongoing bill increase in this scenario because the future revenues from the new customer cohort were never recovered.
- The dotted black line (C) represents the results of a steady decline in the cohort of added new customers, but starting after 15 years in 2040, rather than in Year 1.[81] While there was a period of positive contribution from this cohort, this later decline ultimately leads to bill increases in the long run. It never achieves full payback within the 20-year payback period.

Scenarios (A) through (C) depict a range of increasing risk that is inherent to new connections being implemented under increasing climate policy and competition from

[81] This provides an illustration of a scenario where customer departures do not begin until the initial equipment begins to age out.

alternatives.

In a system with departing existing customers, new growth modestly increases non-migrating customer costs in the near term, while providing a larger benefit in the long run, provided those new customers use the system at levels expected when determining the CIAC. This analysis assumes steady rates; if rates were to rise, new customers would contribute more to the system—but such rises are unlikely to be expected by new customers today and would entice many to reduce or eliminate gas use (see again scenario C above). Ultimately, the fact that new customers today are less tied to the gas system in the long run poses a significant risk to existing customers, which is exactly the subsidy the line extension allowance practice seeks to avoid.

Q. Please provide an overview of the investigation into line extension allowances in D.P.U. 20-80.

A. During the D.P.U. 20-80 investigation, the role of new customers emerged as a key area of focus. The LDCs' report on regulatory designs identified four potential reforms to current Department policy:

1. Reduce customer revenues supporting LEAs;
2. Shorten the payback period for calculating LEAs;
3. Raise the IRR required for the calculated LEA; and
4. Require new customers to guarantee revenues supporting LEAs.[82]

[82] *Future of Gas*, D.P.U. 20-80, Energy & Environmental Economics, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals*, at 36 (Mar. 18, 2022).

In its D.P.U. 20-80-B Order, the Department indicated its intent to review line extension allowances and related new customer connection policies and tasked the LDCs with reviewing such policies.[83] On June 14, 2024, the Department issued a hearing officer memorandum, which formalized several information requests related to the calculation and design of allowances, whether such allowances were inconsistent with Commonwealth policies regarding GHG emissions reductions, and provided data on the number of allowances.[84] The memorandum also requested comments from interested parties on the topics of: (1) whether the LDCs' models and policies accurately maintain the principle that existing customers should not subsidize new customers; (2) whether the policies are consistent with emissions reduction efforts; and (3) any other issues the department should consider when developing a common framework.

On October 7, 2024, in response to the Department's memorandum, I submitted an independent comment responding to this request based on a comprehensive analysis of the LDC's responses as well as other regulatory filings.[85] My analysis had three findings:

1. The LEA policies were significantly inconsistent across the LDCs, with the LDCs using very different assumptions in their determination of LEAs and CIACs.
2. The policies are inconsistent with the principle that existing customers should not be subsidizing new customers. The inconsistencies associated with calculation practices result in LEAs and CIACs varying across LDCs, implying that existing customers in some territories over-subsidize new customers relative to others.

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[83] D.P.U. 20-80-B, Order, at 98–101.

[84] D.P.U. 20-80, Hearing Officer Memorandum (Jun. 14, 2024).

[85] Michael J. Walsh, *Pipeline Extension Allowances and the Future of Gas in Massachusetts*, GROUNDWORK DATA (Oct. 7, 2024).

> Further, increasing uncertainties in gas demand from new customers, who tend to be more efficient and have easier pathways off gas, increase the risk of unrecovered costs from the new customer class.
>
> 3. The policies, specifically those that drive the indiscriminate expansion of the gas system, were inconsistent with the emissions limits and sublimits. Modern electric strategies have delivered greater emission reductions in new construction and conversions from delivered fuels or electric resistance heating. Both market and policy factors have shifted the Department's need for a regulatory approach from one that needed to encourage the gas system's growth, to one that needs to manage its decline.[86]

Other comments, as well as mine, noted that several states have eliminated or reformed line extension allowances, including California,[87] Colorado,[88] Oregon,[89] and Washington.[90]

On February 5, 2025, the Department issued an Initial Straw Proposal for the elimination of line extension allowances with some exceptions.[91] Following the consideration of feedback on the straw proposal, on August 8, 2025, the Department issued Interlocutory Order D.P.U. 20-80-E.[92] In the Interlocutory Order, the Department issued a Revised

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[86] *Id.*

[87] California Public Utilities Commission, Decision 22-09-026 (Sept. 20, 2022).

[88] Colorado General Assembly, Senate Bill 23-291: Utility Regulation (2023), https://leg.colorado.gov/bills/sb23-291.

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

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

[91] *Future of Gas*, D.P.U. 20-80, Hearing Officer Memorandum (Feb. 5, 2025).

[92] *Future of Gas*, D.P.U. 20-80-E, Order (Aug. 8, 2025).

Straw Proposal. It tasked the LDCs to file draft tariffs necessary to implement the Revised Straw Proposal for review in the Climate Compliance Plan Dockets. The Department also, in its response to the LDCs' Joint Motion for Clarification, provided the companies with an opportunity to submit additional evidence in response to Interlocutory Order D.P.U. 20-80-E.[93] On October 20, 2025, the LDCs responded to this with testimony and a revised tariff.[94]

Q. What are the LDCs' major criticisms of the Department's proposed line extension allowance policy?

The LDCs have raised several criticisms of the Department's straw proposals. The companies claim that, if adopted, the Revised Straw Proposal will:

- Unfairly limit customer choice;[95]
- Harm the financial integrity of the gas system;[96]
- Result in the subsidization of existing customers by new customers;[97]
- Excessively burden the electric grid;[98]

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93 *Future of Gas*, D.P.U. 20-80-F, Order, at 10 (Sept. 5, 2025).

94 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1.

95 *Id.* at 33; *Future of Gas*, D.P.U. 20-80, LDC Joint Motion for Clarification, at 28 (Aug. 28, 2025).

96 *Future of Gas*, D.P.U. 20-80, LDC Joint Motion for Clarification, at 15.

97 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 17–18; *Future of Gas*, D.P.U. 20-80, LDC Joint Motion for Clarification, at 44–46.

98 *Future of Gas*, D.P.U. 20-80, LDC Joint Motion for Clarification, at 27; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 65; *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 36; *Berkshire Gas*, D.P.U. 25-40, Exh. BGC-CCP, at 15.

- Encourage the adoption of more carbon-intensive fuels;[99]
- Contravene the role of the Municipal Fossil Fuel Free Demonstration Project;[100]
- Cost parity of gas and electric buildings has not yet been reached;[101] and
- Negatively impact housing production.[102]

Q. Does the Revised Straw Proposal unfairly limit customer choice?

A. No. The objective of the Revised Straw Proposal is to mitigate concentrated risks associated with stranded consumer and utility asset costs, with the broader aim of preserving affordability and maintaining optionality for current customers. The granting of an allowance reflects an investment decision by the utility, on behalf of its current customers, who will be responsible for paying the near-term revenue requirement. Current customers have no choice in making this investment but bear the risks of it.

Customers make better choices when they receive clear price signals. Customers' interest in gas reflects a decades-old understanding of the gas system that has been shaped by utility marketing and a perception that gas is the preferred fuel on climate, affordability, and consumer value fronts.[103] The rebalancing of connection costs and risk to new customers

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[99] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 27–29; D.P.U. 20-80, LDC Joint Motion for Clarification, at 7.

[100] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 37.

[101] *Id*. at 36–37.

[102] *Id.* 37.

[103] The D.P.U. 20-80 Independent Consultant Analysis and the LDCs' Assessment of Transition Costs clearly demonstrate that the gas system is transitioning to a new paradigm where its "most affordable fuel" value proposition no longer applies. It will take several years for consumers to incorporate this new understanding into their decision-making.

sends an important price signal that seeks to overcome the inertia of this outdated perception and better convey future risks associated with their individual gas investment.

Q. Does the proposal threaten the financial integrity of the gas system?

A. No. The LDCs make a circular argument by claiming the Companies need LEAs to support expansion to maintain financial health. This essentially argues that the LDCs need continuous growth to remain viable. A truly financially sound utility should be able to maintain operations in the absence of growth. However, the real issue here is that both increasing competition and climate action risk (not solely Massachusetts policy nor Department action) will fundamentally erode the financial viability of the gas system. Gas regulation has entered a new paradigm and needs to adjust. The risk of stranded assets is steadily increasing due to factors that are largely outside the Department's control. By disallowing the LDCs' inconsistent LEA policies for most connection cases, the Department is exercising prudent regulation via a price signal to preserve the financial viability of the gas companies as long as possible.

Q. Would the Revised Straw Proposal result in the discriminatory subsidization of existing customers by new customers?

A. No. The customer would not be "paying for the incremental infrastructure cost two times"[104] under the Revised Straw Proposal. The Revised Straw Proposal reallocates the risk burden of new investments from existing customers, who are closely integrated with the gas system, to new customers. These new customers have greater flexibility before

[104] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 32.

their connection and are more prepared to assume the risks associated with a transitioning gas system. CIAC calculations have always involved regulatory discretion about risk allocation. The Department is simply exercising that discretion differently in light of changed circumstances. The Revised Straw Proposal acknowledges that the disruption in the gas system warrants a reconsideration of how risk is assessed and managed.

A customer paying for the full cost of the interconnection means that the cost will no longer be rate-based. The Revised Straw Proposal intends to shield existing customers from the risk of rate-based new interconnection costs while sending clear price signals to potential new customers. The new customer is now paying the full cost of the interconnection, as well as the infrastructure covered by the revenue requirement to which that new connection was added.

The LDCs contend "that distribution rates are *perfectly* calibrated (*at that moment in time*)" to recover costs.[105] The usage of "perfectly" here implies a foresight that does not exist, not even at a specific moment in time with the determination of CIACs and allowances. The LDCs' methodologies for calculating CIACs and allowances are inconsistent and imperfect in terms of their assumptions, designs, and outputs, yielding differences in CIACs as much as $2,000 for a $5,500 residential connection, even with harmonization of

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[105] *Id*. at 31.

some underlying assumptions, such as rates and weighted average cost of capital.[106] If rates were "perfectly calibrated" these discrepancies would not exist. Furthermore, the LDCs' projections of future customer usage revenues varied widely across default CIAC calculator values and were much higher than the average utilization of new customers reported in revenue decoupling adjustment filings.[107] This evidence of significant disparate impacts in current LEA practice implies that, across LDCs, some new customers are over-subsidized relative to others. The Revised Straw Proposal ultimately reflects a rebalancing of social priorities. Such a rebalancing does not imply that the Revised Straw Proposal enables discriminatory rates, nor does it imply that new customers are subsidizing existing customers.

Q. Are line extension allowances needed due to a lack of sufficient electrical capacity?

A. No. Claims of inadequate electrical capacity are unsupported. Such arguments need to be backed up by more substantial data because they would reflect an area of urgent attention for the Department. The high performance of new construction is so efficient that these incremental winter heating loads are a fraction of existing loads. The electric distribution system in Massachusetts is currently designed to handle an annual summer peak and should thus have sufficient headroom for additional electrical loads. While there may be pockets where adding new electrical loads is challenging, it is essential to identify these areas

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106 *Id.* at 27–28. While only Liberty, Berkshire and Unitil's CIAC calculators were tested, there were significant differences observed in the design of National Grid's and Eversource's calculators.

107 *Id.* at 24.

transparently.[108] Further, there may be supply chain constraints on distribution or customer equipment. While those constraints will need to be overcome to meet the long-term needs of electrification, setting appropriate price signals that facilitate a market shift towards electrification can help attract the investment needed to overcome those barriers.

Q. Would eliminating line extension allowances lead to continued or increased reliance on higher carbon-intensity fuels?

No. The argument that the abolition of line extension allowances will lead to an increase in fuel oil or propane use is inconsistent with policy and market trends. The Survey of Construction indicates negligible (1 percent or less) installations of heating oil in new multifamily or single-family homes in 2024.[109] Oil-to-gas conversions are no longer a distinctive strategy for reducing emissions from homes. The heat pump market and retrofit practice have matured sufficiently to provide multiple strategies that can benefit customers and achieve greater emissions reductions. There are substantial State policies, incentives, and market conditions favoring electrification over the use of distributed fuels. Customers who chose delivered fuels would forgo lucrative credits, pay the additional costs for tank infrastructure, and introduce themselves to the risk of future emissions regulation. Even in situations where customers may choose to use such fuels, it is increasingly likely that they would be used in a dual-fuel capacity. The low utilization rate of fuels in dual-fuel

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108 National Grid's New York affiliate publishes an electrification capacity map: https://systemdataportal.nationalgrid.com/NY/.

109 U.S. Census Bureau, *Characteristics of New Housing, Annual Characteristics, Heating Fuel,* https://www.census.gov/construction/chars/current.html.

scenarios economically preferences distributed tank infrastructure rather than expensive pipeline infrastructure.

Q. Does the Revised Straw Proposal contravene the role of the Municipal Fossil Fuel Free Demonstration Project?

A. No. Section 83(d) of *An Act Driving Clean Energy and Offshore Wind*[110] establishes the role of the municipal pilot to study the implementation of more advanced codes. The pilot will track and analyze relevant data such as construction costs, overall housing production, housing affordability, utility usage, customer costs, permitting, and energy ratings of constructed buildings. A control group will be used for comparison. The primary purpose of this study is to facilitate continuous improvement of the Commonwealth's building code, municipal code adoption and permitting, and contractor practice. It does not preclude the Department from taking action that reduces risk to existing customers or even fulfill its mandate to balance progress towards the emissions limits and sublimits.

Q. How do the costs of all-electric new construction compare with gas?

A. In most building classes, all-electric construction has reached effective cost parity with gas, meaning that the premium of all-electric construction relative to a comparable gas-served building is less than 1 percent of total building costs. The LDCs acknowledge such closeness with respect to single-family homes but contend "there is not the same level of parity for multi-family buildings, including low-income multi-family. Further, no study

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[110] St. 2022, c. 179 §83(d).

supports uniform parity for C&I."[111]

This claim stands in contrast to available data. The green building industry group, Built Environment Plus, has tracked Net Zero Ready[112] construction from 2022 to 2024.[113] The most recent inventory found:

- Nearly 50 million gross square feet ("MGSF") of Net Zero Ready buildings have been built.[114]
- Of the 13.1 MGSF that reported cost data, 80 percent reported <1 percent cost premium.
- Multi-family (19 percent of total floor space) and affordable housing (13 percent of total floor space) units were the most common typology tracked in this data. The multifamily and affordable housing cohort included buildings that also exhibited the greatest savings (< negative3 percent) and highest cost premiums (>5 percent).
- Many buildings of varying types (education, mixed use, office) exhibited no significant difference in costs.

This is a limited data set. However, it does demonstrate that: (1) all electric buildings, including multifamily and affordable housing, are not cost-prohibitive and can be cheaper; and (2) the concerns raised by the LDCs can be best addressed through other policy mechanisms rather than by existing gas customers bearing risks associated with new

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111 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 32.

112 Built Environment Plus defines Net Zero Ready as: (1) buildings in Massachusetts; (2) that achieve one of several high-performing standards (e.g., Stretch Code); and, (3) are all electric for normal building heating operations and ambient temperature is above 99 percent of the ambient design condition, except for health care and laboratory buildings which must rely primarily on heat pumps but are given more leeway in fuel use.

113 *The Road to Net Zero (Spring 2022, 2023, and 2024 Updates),* BUILT ENVIRONMENT PLUS, https://builtenvironmentplus.org/road-to-net-zero/.

114 For comparison, Boston has approximately 650 MGSF.

connections. The fact that there are examples of significant cost savings for all-electric multifamily shows that there are pathways to cost savings that could inform future projects. Furthermore, both industry[115] and independent[116] studies in Massachusetts have shown that the cost of building homes with gas is higher than with electricity under the current code structure, because electrification can avoid the costs of gas pipes and ductwork. Any affordability concerns for specific LMI customers that would arise because of the Revised Straw Proposal are likely influenced by other factors that are best addressed through alternative means, as the proposal's intent is to ensure broad benefits for LMI customers through lower rates.

Q. Will the elimination of allowances impact housing production?

A. Early evidence from Massachusetts suggests that polices that avoid gas use will not impact housing. A profile of Lexington's adoption of the Specialized Code and participation in the municipal pilot highlights a surge in housing production that will increase available housing in the town by 9 percent.[117] The profile emphasizes that the core driver of this surge is a 2023 change in the town's zoning rules and highlights a developer who noted

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115 P. Bakhshi, et al., *Public Policy for Net Zero Homes and Affordability*, Wentworth Institute of Technology (WIT), Massachusetts Institute of Technology (MIT), and Home Builders & Remodelers Association of Massachusetts (HBRAMA) (Jun. 2023), https://hbrama.com/wpcontent/uploads/2023/05/Public-Policy-for-Net-Zero-Homes-and-Affordability-Final-6-14-23.pdf.

116 Michael J. Walsh, *Pipeline Extension Allowances and the Future of Gas in Massachusetts*.

117 Sarah Shemkus, *This Massachusetts town banned gas — and housing boomed anyway*, CANARY MEDIA (Aug. 6, 2025), https://www.canarymedia.com/articles/electrification/massachusetts-gas-ban-housing-impact.

bill savings for residents and increasing contractor capabilities with higher-performing and all-electric buildings.

The housing affordability crisis is a concern, largely driven by macroeconomic factors and various zoning and development regulations. In our example, shown in Figure 3 above, a $10,000 connection cost would require a CIAC of $7,051. This implies a potential new cost to the customer of at least $3,000, depending on tax accounting. These values are reasonable based on my previous exhaustive review of allowance and CIAC policy. This is approximately 0.5 percent of per-unit construction costs in the Boston area.[118] Further, housing costs are best addressed through other policy reforms rather than spreading the costs of infrastructure at risk of underutilization to existing ratepayers, many of whom have also absorbed the high cost of housing to varying degrees.

Q. Should the Department revise its Revised Straw Proposal?

A. The Department should adopt the Revised Straw Proposal as written. The proposed policy largely aligns with those enacted in California,[119] Maryland,[120] New York,[121] and

[118] Tim Logan et al., *The $600,000 Problem*, THE BOSTON GLOBE (Dec. 22, 2023), https://apps.bostonglobe.com/2023/10/special-projects/spotlight-boston-housing/construction-costs/.

[119] California Public Utilities Commission, Decision 22-09-026 (Sept. 20, 2022).

[120] Public Service Commission of Maryland, Order No. 91683: Order on Stakeholder Proposals for Revision of Gas Policy (Case No. 9707).

[121] Pending approval by Governor: Senate Bill S8417 relates to the provision of gas service to new customers (2025), https://www.nysenate.gov/legislation/bills/2025/S8417.

Colorado.[122] This is a straightforward approach to implementing effective price signaling to align the management of the gas system with the clean energy transition. The policy's only exception would allow for projects that can demonstrate no technically feasible alternative to the use of natural gas resources to qualify for an LEA. To be eligible for such an allowance, the LDC would have the burden of demonstrating that the customer has no technically feasible alternative and that the incremental costs to connect the customer do not exceed the incremental revenues from the customer's connection.

The Revised Straw Proposal aligns with guidance developed by National Regulatory Research Institute that observed that "[t]he basic elements of a good line-extension policy should balance the criteria of fairness, reasonableness, economic efficiency, and predictability."[123] The proposal is represents a reasonable and prudent rebalancing for the future of gas service in Massachusetts.

Q. Do the LDCs raise any concerns about the language of the straw proposal in D.P.U. 20-80-E?

A. Yes, the LDCs criticize the exception to the straw proposal, which "preserves the ability for a potential customer to demonstrate that *technically* feasible alternatives to the use of natural gas for a particular application do not exist, and thus, a line extension allowance

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[122] Colorado General Assembly, Senate Bill 23-291: Utility Regulation (2023), https://leg.colorado.gov/bills/sb23-291.

[123] Ken Costello, *Line Extensions for Natural Gas: Regulatory Considerations* (Report No. 13-01), National Regulatory Research Institute (2013), https://pubs.naruc.org/pub/FA86B6C6-E91D-FF76-882F-04081293B088.

may be appropriate."[124] The LDCs argue that "technically feasible" is impermissibly vague to the point it "subverts the prudence standard."[125] The Companies further argue that the straw proposal could result in unlawful discrimination among customers.

Q. Do you agree with the LDCs' concerns regarding "technical feasibility"?

A. No, the LDCs' criticisms are unfounded. Clearly, the project applicant, in conjunction with the LDC, must demonstrate that it is not technically possible to electrify the building or install an alternative decarbonized energy solution sufficient to meet the customer's demand.[126] The word "technically" clarifies that the "feasibility" consideration is not an economic consideration because such a threshold would be overly subjective—how much more costly would the alternative need to be to satisfy this condition?[127] The AGO previously recommended "technical feasibility" because the LEA itself biases economic comparison in favor of gas, making non-gas alternatives appear less economically feasible.[128]

Furthermore, the fact that "technically feasible" is not strictly defined does not then "subvert[] the prudence standard." If adopted, the Revised Straw Proposal would allow the Department appropriate discretion to consider all factors that may influence technical

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[124] D.P.U. 20-80-E, Order, at 16.

[125] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. LDCs-1, at 42–43.

[126] *Future of Gas*, D.P.U. 20-80, AGO Comments, at 11 (Apr. 2, 2025).

[127] *Id*.

[128] *Id*.

feasibility, such as accessibility of alternatives, whether the alternatives can meet the specific needs of the prospective customer, and electric load capacity. This broad discretion is akin to the Department's broad authority to "consider the totality of the circumstances" when reviewing a petition for gas service from a new or existing customer under G.L. c. 164, § 92 (amended by St. 2024, c. 239 § 77).

Q. Please provide hypothetical examples of "technical feasibility" analysis.

Consider, for example, a partnership between an EDC and an LDC to provide baseload power via a methane fuel cell and a carbon capture system. The system is efficient at generating electricity needed to meet load growth, does not emit criteria pollutants, and produces CO_2 that could be used to make beer at a local brewery—all ideal outcomes. Further, the arrangement has a clear lifetime and high utilization of the gas system. While the products might be substituted via other means, feasibility ultimately rests on whether this specific production service can be accomplished without pipeline gas. Right now, likely not. There is no feasible or "capable" alternative.

In another example, a hospital in a dense location might demonstrate that there is no feasible or capable alternative to gas that meets the hospital's design needs, including: (1) the need for a dedicated combustible fuel source, and (2) constraints on using a tank fuel.

In both examples, customers are likely to be tied to the gas system for a long time and have throughput that justifies with certainty, through a robust CIAC calculation, and appropriate payment that mitigates risk for existing customers. The standard is open to interpretation and provides appropriate flexibility.

Q. How would the proposed line extension allowance policy in Interlocutory Order D.P.U. 20-80-E impact ratepayers?

A. If adopted, the straw proposal would benefit existing gas ratepayers. First, it would put immediate downward pressure on near-term gas rates due to lower capital expenditures that are rate-based. Second, in the long run, it would eliminate risks associated with underutilized or stranded infrastructure. Third, it would provide clarity about the long-term risks of the gas system to new customers. Finally, it would help the Commonwealth achieve its climate goals by avoiding gas at the point of significant infrastructure investment, generally the most cost-effective opportunity to reduce emissions in the sector.

C. <u>New Customer Connections Should Be Disallowed in Areas Designated for Electrification Via an NPA Assessment or Integrated Energy Planning ("IEP").</u>

Q. How would the proposed NPA framework impact new customer connections?

A. As part of the CCPs, the LDCs submitted a common draft NPA framework for Department review and approval, in accordance with the requirements of D.P.U. 20-80-B. The draft NPA framework lays out an alternatives evaluation process for several program areas associated with LDC investment. The framework seeks to identify opportunities to avoid conventional gas system investments in favor of lower-cost alternatives that may align with efforts to reduce emissions.

New customer connections are handled under a separate section from the main framework. The LDCs propose that the company provide information on alternatives to gas, and new customers must sign a customer acknowledgment indicating they have been informed of such alternatives before being connected.[129] The LDCs contend that, in their franchise areas, they are obligated to serve new customer requests.[130] In legal comments filed with the Department on October 3, 2025, the AGO argued that the LDCs do not have an obligation to serve new customers.[131] An effective NPA framework would identify opportunities where targeted electrification could avoid conventional gas system investment.

Q. How should new customer connections be considered in areas that have been identified as areas designated for targeted electrification, either via an NPA assessment IEP?

A. New customer connections should be constrained in areas identified for electrification via an NPA assessment or IEP. New gas customers present a specific problem for IEP and NPA efforts. They are likely to represent higher-performing customers due to building code requirements or efficiency measures associated with oil-to-gas conversions. These customers lock in new gas infrastructure and use the system less than existing customers. They will be easier to convert (e.g., the prewiring requirements of new building codes), but may still require outreach and incentives to transition away from gas after being connected. This increases the challenge of implementing an NPA. The cheapest way to reduce gas use is to avoid a new connection.

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[129] *See, e.g., Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, Att. 3, at 5 (The jointly-proposed NPA framework is listed as Attachment 3 for all LDCs).

[130] *Id*. at 4.

[131] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, AGO Obligation to Serve Comments, at 12–13 (Oct. 3, 2025).

Q. Please describe National Grid's "zero-carbon" new customer connection policy.

National Grid proposes that it will explore "options for 'Low-Carbon' new connections" through 2030 as a precursor to "design and implement a low-carbon new connection requirement" effort between 2031 and 2035.[132] National Grid describes a program operated by Énergir in Quebec that requires new gas customers to rely exclusively on "renewable" natural gas ("RNG") for gas service—presumably through the procurement of RNG attributes. National Grid describes the requirements of such a policy—"customer[s] will need to meet certain energy efficiency standards, deploy hybrid gas/electric heating, and/or use low-carbon fuel."[133]

Q. Is this a sound strategy?

A. No. Requiring new gas connections to meet certain energy efficiency standards is unnecessary and redundant for new construction. Massachusetts already has some of the most robust building energy codes in the country, and they will likely remain ambitious into the 2030s. As described above, the Stretch and Specialized codes already impose more stringent requirements on fossil fuel customers. DOER has acknowledged that its multi-tier code poses challenges for developers and has invested significant effort to ensure that requirements for each tier are clearly communicated.[134] The proposal is thus unnecessarily

[132] *National Grid*, D.P.U. 25-41, Exh. NG-CCP at 57, 61.

[133] *Id*. at 61.

[134] *See* Table 3 above summarizing DOER's Residential Stretch and Opt-In Codes.

burdensome, as it would likely require additional compliance reviews for developers and National Grid.

IV. LOW CARBON FUELS

A. <u>“Low-carbon” Fuels (“LCFs”) are Not an Appropriate or Cost-Effective Investment for Climate Compliance.</u>

Q. What are LCFs?

A. LCFs[135] are energy carriers that, when burned, do not emit fossil carbon directly into the atmosphere, in contrast to fossil fuels. The term encompasses non-fossil forms of gaseous, liquid fuels,[136] and solid fuels.[137] Typically, LCFs are produced from biomass synthesized from captured CO_2, or, in the case of hydrogen, produced and consumed in a manner that does not involve the capture or release of carbon. Figure 5 below shows that many pathways exist for creating LCFs alongside conventional fossil fuel pathways. LCFs simply substitute for fossil petroleum and fossil natural gas in these pathways.

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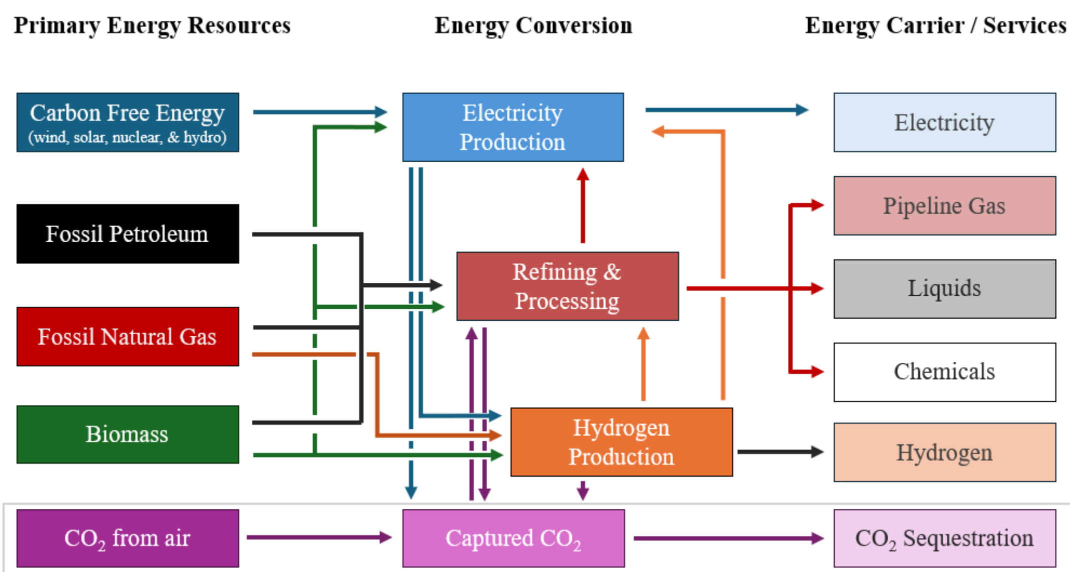
[135] Analogous terms for LCFs can include “renewable fuels,” “decarbonized fuels,” or “alternative fuels.” These terms, including “LCFs,” are generalizing descriptors, and the impact of such fuels relative to fossil fuels depends on several factors. For example, corn-derived ethanol fuels are classified by the Federal Renewable Fuel Standard as a “renewable fuel,” however, comprehensive life cycle assessments have shown that it is potentially more carbon-intensive than fossil gasoline due to process energy requirements and land use impacts (*See* T. J. Lark, et al., Environmental outcomes of the US Renewable Fuel Standard. *Proc. Natl. Acad. Sci. U.S.A.* (2022), https://doi.org/10.1073/pnas.2101084119).

[136] Examples of liquid LCFs include methanol, dimethyl ether (used as a propane substitute), ethanol, renewable gasoline, biodiesel, renewable diesel, and sustainable aviation fuel.

[137] Examples of solid LCFs include cordwood, pelletized biomass, and biochar (charcoal).

Figure 5. Overview of energy production.



Q. Please summarize the Department's directives concerning LCFs in Order 20-80-B.

A. In Department Order 20-80-B, the Department expressed concerns about the high cost, uncertain carbon intensity, and potential limited availability of LCFs.[138] While the Department supported the option for customers to voluntarily purchase RNG from their LDC or a supplier, the Department required any costs associated with RNG to be fully borne by participants or shareholders.[139] The Department, however, did not issue a finding on how LCFs would contribute to emissions reductions, specifically noting the uncertain carbon intensity of LCFs, but did note that it would entertain proposals for targeted end

138 D.P.U. 20-80-B, Order, at 68–69.

139 *Id.* at 71.

uses such as "high-temperature industrial processes," while requiring a cost-effectiveness screen or demonstration of net benefits.[140]

Q. Please summarize the LDCs' positions on LCF expressed in their CCPs.

A. The LDCs argue that incorporation of LCFs is necessary to achieve emissions limits and provide customers with choice.[141] While all the LDCs acknowledge some degree of limitation in LCF supply in Massachusetts, as well as at the national level, and some further acknowledge that the incorporation of LCFs is secondary to electrification, the LDCs nonetheless propose to monitor developments in both RNG and hydrogen markets as a strategy to meet the Commonwealth's decarbonization goals.[142] The LDCs make several arguments in favor of these strategies and recommend policy changes that would enable the LDCs to integrate LCFs into their product portfolios. Specifically, the LDCs recommend that the Department develop a regulatory standard for life cycle assessment for RNG and hydrogen.[143]

Q. Do LCFs reduce emissions and support net-zero targets?

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140 *Id.* at 84.

141 *Berkshire Gas*, D.P.U. 25-40, Exh. BGC-CCP, at 47; *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 69; *Liberty*, D.P.U. 25-43, Exh. LU-CCP, at 40; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 101.

142 *Berkshire Gas*, D.P.U. 25-40, Exh. BGC-CCP, at 37; *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 76–77; *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 52; *Liberty*, D.P.U. 25-43, Exh. LU-CCP, at 41–42; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 63.

143 *Berkshire Gas*, D.P.U. 25-40, Exh. BGC-CCP, at 37; *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 93; *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 52; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 180.

A. Simplistically, LCFs may, depending on the circumstances, contribute to *incremental* emissions reduction by substituting for fossil-based fuels. The role of LCFs in meeting *systemic* net zero targets, however, is much more complex. For one, LCFs vary in their life cycle carbon emissions, particularly where the cultivation and production of LCFs require significant energy demand from fossil-based resources, in addition to generating powerful GHGs, like methane and nitrous oxide (N_2O) through processing or agricultural cultivation. Furthermore, LCFs that are produced from agricultural or forestry products can lead to changes in cultivation practices and land use that can significantly increase GHG emissions. Ideally, LCFs produced from waste-based feedstocks can be targeted for high-value end uses such as higher value energy-dense liquid fuel products (e.g., aviation fuel), distinct energy system services (e.g., load-following biogas generator serving rural electric needs), or decarbonized industrial applications such as ammonia (fertilizer) production.

Notably, the LCFs that the LDCs primarily focus on in their CCPs are RNG and hydrogen, which the LDCs propose to utilize to achieve incremental emissions reductions in heating. Such an application, however, is well understood to be an inadvisable use of LCFs.

Q. How should the Department respond to the LDCs' proposals regarding LCFs?

A. I recommend that the Department reject the LDCs' proposals regarding LCFs. The LDCs have failed to produce a sufficient understanding of the complexities of LCFs in the five years since the Department opened its investigation in D.P.U. 20-80. While broader state-level heating-sectors and economy-wide emissions policies have yet to be solidified, the

Commonwealth, particularly MassDEP, appears to be continuing its practice of allowing alternative compliance mechanisms or payments that give "hard-to-electrify" customers sufficient, low-cost flexibility. Accordingly, the Department need not duplicate MassDEP's efforts by, as the LDCs suggest, carving out and favoring specific RNG and hydrogen pathways, two fuels that are demonstrably inferior decarbonization technologies for the heating sectors. Moreover, the Department and the LDCs must focus on the adaptation of an LDC business model for a future in which gas consumption is much lower than it is today, and the LDC's climate compliance efforts should predominantly focus on reducing gas consumption, not adjusting the carbon intensity of fuels which has economy-wide implications.

Q. What is RNG and how is it incorporated into the gas system?

A. RNG, or methane from biological sources, is mainly produced today by purifying biogas from landfills or anaerobic digestors[144] that process wastewater sludge, animal waste, and food scraps. Biogas,[145] however, must be upgraded to pipeline-quality methane before injection into gas systems. Moreover, crop residues, forest scraps, energy crops, and municipal solid waste can be gasified[146] directly into RNG. While traditionally raw biogas

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[144] Anaerobic digestors is biological process in which methanogenic bacteria break down organic matter in the absence of oxygen ("an-": without; "aerobic": oxygen).

[145] Raw biogas is approximately 40-50 percent CO2, and 40-50 percent methane, with residual water and trace gases.

[146] Reacting organic material at high temperatures with varying levels of steam and oxygen without combusting it.

has been combusted for heat or electricity, all the feedstocks above can serve other purposes, such as power generation, liquid fuels, fertilizers, chemicals, or carbon sequestration.

Q. What is hydrogen and how is it incorporated into the gas system?

A. Hydrogen is a gas that is widely used in the chemicals industry; it is also the simplest molecular energy carrier and can be produced through several pathways. Steam reforming, the main method for producing hydrogen, reacts methane from natural gas with steam to create hydrogen, but this process is energy-intensive, relies on natural gas, and emits significant CO_2. Achieving low-carbon hydrogen requires alternatives like water electrolysis powered by clean electricity. Once produced, hydrogen can be combusted directly to produce heat, used to power a fuel cell to generate electricity for grid and transportation applications, and serve as a chemical feedstock in the production of fertilizer, hydrocarbon fuels, and other chemicals.

Hydrogen, however, presents major challenges for existing gas systems due to its unique properties.[147] In fact, hydrogen can cause steel embrittlement, easily leaks, and has only a third of the energy per volume compared to natural gas, meaning that supplying equivalent energy requires tripling the flow rate. These factors lead to significant integrity and leakage concerns for natural gas networks and require significant investment even if hydrogen is blended at low levels. Indeed, dedicated hydrogen networks would require novel network

[147] *See CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. C, at 52–59. Appendix C provides a comprehensive technical and policy review of low-carbon fuels.

and consumer equipment. While some LDCs consider "H_2 clusters" in their long-term plan, they do not provide a specific use case other than customers potentially requiring options other than electrification. National Grid also cites an example of a behind-the-meter customer pilot,[148] but even when asked about more practical planning aspects, it did not provide sufficient details to meaningfully consider strategy in a planning context.[149]

Q. How do the LDCs propose to utilize RNG and hydrogen to meet the Commonwealth's decarbonization goals?

A. In the CCPs, the LDCs propose that RNG and hydrogen can serve as alternatives to fossil methane. Specifically, to incorporate RNG into gas policy, the LDCs propose adopting procurement, accounting, and attribution frameworks. Under such a system, RNG could be produced anywhere in the country, injected into a gas pipeline network, and the environmental attribute[150] of the RNG would be sold to a consumer in Massachusetts.[151] These attribute arrangements present important tradeoff considerations. For example, one objective of the Commonwealth's Renewable Energy Portfolio Standard is encouraging the development of local energy resources, and heat pumps utilize locally sourced heat.

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148 *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 74.

149 *National Grid*, D.P.U. 25-41, Exh. AG-1-15.

150 An environmental attribute refers to the distinct environmental benefit or characteristic associated with a unit of energy or fuel, such as reduced greenhouse gas emissions, renewable origin, or other sustainability features. These attributes are often tracked and traded separately from the physical energy product, allowing entities to claim credit for the environmental benefits—such as through renewable energy certificates (RECs) or carbon offsets—even if the physical energy is delivered elsewhere.

151 Unitil provides the most detailed description of the separation of RNG physical molecules and environmental production attributes. *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 53.

The LDCs' proposals, however, have a limited impact on the composition of materials transported through pipelines in Massachusetts, and may affect national bioenergy markets that operate across different sectors and require consistent alignment with out-of-state emissions accounting. Further, with respect to hydrogen, the CCPs consider local strategies that include hydrogen blending, dedicated hydrogen networks, and post-consumer reforming of gas into hydrogen. The LDCs claim that these pathways would displace demand for natural gas.

Q. Both National Grid and Eversource recommend that the Department develop an accounting or lifecycle standard for RNG and hydrogen to monitor out-of-state lifecycle emissions. Should the Department pursue such a program?

A. No. G.L. c. 21N, §2, tasks MassDEP with monitoring emissions and establishing the Commonwealth's greenhouse gas inventory. Further, EEA is currently exploring modifications to the Commonwealth GHG inventory and developing a multi-state common accounting framework for carbon sequestration as it pertains to natural working lands.[152] Accordingly, any system that needs to account for life cycle and out-of-state impacts should be under the auspices of MassDEP to ensure consistency of accounting.

Q. Are the LDCs' LCF proposals consistent with research on the role of LCFs in Massachusetts?

A. No, the LDCs' proposals run counter to established research. The 2050 Roadmap demonstrated that RNG is an inferior decarbonization strategy,[153] illustrating in an energy

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152 *2025/2030 CECP*, at 101.

153 *See CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. C, at 47.

market simulation that, rather than decarbonizing RNG, it is more cost-effective to continue residual fossil gas use under the gross emissions allowance of Massachusetts' 2050 net-zero limit.[154]

Moreover, industry-sponsored research corroborates the 2050 Roadmap's findings in a national context. For example, a study conducted by the Low Carbon Resources Initiative, a joint effort by the Electric Power Research Institute and the Gas Technology Institute, showed negligible LCF use in the building sector under most scenarios evaluated.[155] In nearly all "net zero" scenarios, fossil gas in the building sector is preferred over RNG to manage residual emissions. In fact, only in scenarios where carbon markets are constrained, or there is limited potential for negative emissions, do RNG and hydrogen become significant.

Q. The LDCs argue that LCFs are specifically needed to achieve emissions sublimits, and that the CECPs justify the inclusion of LCFs in the CCPs. Is this a reasonable interpretation of the 2025/2030 CECP?

A. No, the LDCs selectively pull statements from the 2025/2030 CECP while glossing over other important findings. The 2025/2030 CECP is clear that the key metric is a "5 percent

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154 2050 Roadmap, at 50–52; Energy Pathways to Deep Decarbonization, *A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study*, at 81–84. It is worth noting that the Pathways analysis included some illustrative uses of hydrogen for the transportation sector and utilizing 5 percent hydrogen blending with pipeline gas, but this analysis was not meaningfully comprehensive enough to draw conclusions for the entire gas distribution system.

155 G. Blandford, Net-Zero Scenarios 2.0: Sensitivity Analysis and Updated Scenarios for LCRI Net-Zero 2050, EPRI (Dec. 2024), https://www.epri.com/research/products/000000003002031777.

reduction in the *carbon intensity of pipeline gas* and a *20 percent reduction for fuel oils by 2030*,"[156] which was included to achieve the 2030 limit and sectoral sublimits, and the pathways modeled assume "a blend of bioenergy from certain feedstocks and that these fuels contribute to meeting the Commonwealth's gross emissions limits and sublimits."[157] This metric, however, does not prescribe *how* the reduction in carbon intensity is met.

Significantly, the 2025/2030 CECP was clear that the contribution of LCFs to the 2030 target was predicated on the need for additional "research and deliberation…to determine how to integrate these fuels into the Commonwealth's policy portfolio and emissions inventory accounting methodology."[158] Further, the 2025/2030 CECP called for the development of a net-zero, multi-state accounting framework and the design of a viable carbon sequestration market.[159] The 2050 CECP reiterated these points, emphasizing "Review Emissions Accounting for Alternative Fuels" on an economy-wide basis and "Accelerate Innovation" as future implementation actions.[160] The development of both is necessary for the incorporation of LCFs into existing fuel markets.

Q. How do the economics of RNG and hydrogen impact the viability of pursuing strategies for the decarbonization of utility gas?

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156 *2025/2030 CECP*, at 29 (emphasis added).

157 *Id.*

158 *Id.*

159 *Id.* at 101–02.

160 *Id.* at 141.

A. The high costs of RNG and hydrogen, compared to fossil gas, electric strategies, and other alternative fuels, highlight that both are inferior LCF strategies. Renewable fuels are generally more expensive than fossil fuels, due to the higher costs of sourcing feedstocks and the infrastructure and energy inputs required to process those feedstocks into fuel. For example, the cost of biomass feedstock for RNG—manure management, biomass, etc.—exceeds the cost of fossil gas. The capital needs of a digestion-purification or gasification facility are also considerable due to the complex equipment and interconnection costs, and energy inputs alone to produce RNG are equivalent to the cost of a conventional fossil gas supply. Moreover, RNG faces a high "decarbonization premium" due to low fossil gas prices: RNG production costs are typically estimated to exceed $20 per MMBtu, while fossil gas production costs range from $2 to $5 per MMBtu.[161]

Q. The LDCs claim that RNG use is growing, is this true?

A. The RNG market has grown recently, but this growth is largely driven by the RNG attribute market. The price of an RNG attribute has, at times, exceeded $80 per MMBtu, while the commodity cost of natural gas is below $5 per MMBtu. These subsidies are widely recognized as an unfortunate outcome of poor policy design.[162]

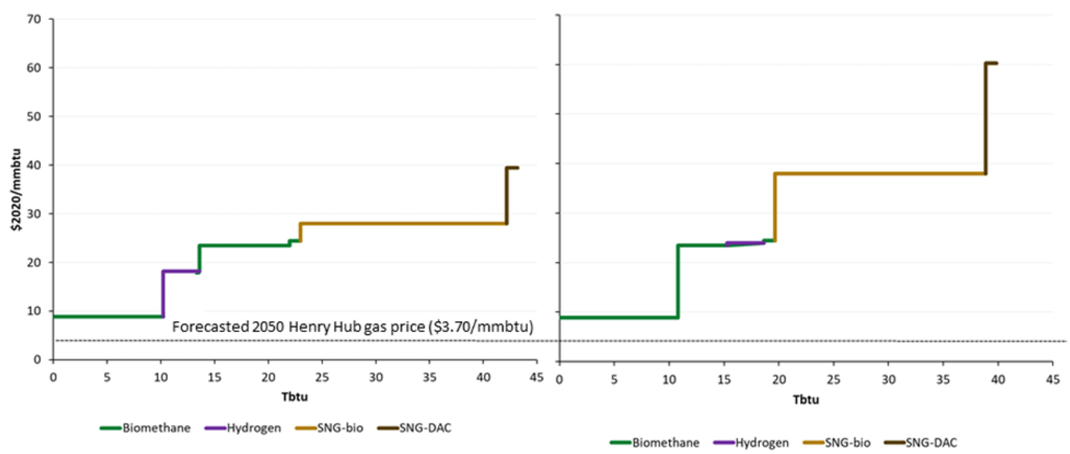
Q. The LDCs claim that as the market further expands, economies of scale will lower costs, making this solution more accessible to customers and increasing demand. Is this assessment accurate?

161 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. C, at 40–41.

162 *Id.*

A. No, in fact, the opposite is true. Figure 6 below shows RNG supply curves from the D.P.U. 20-80 Independent Consultant Report—these charts demonstrate increasing cost with growing consumption, with supply prices reaching approximately $40/MMBtu when at ~40-45 TBtu of usage by gas customers in the state, which is equivalent to approximately 10 percent of statewide gas consumption in 2024.[163]

Figure 6. Renewable gas supply curves used in the 20-80 independent consultant pathways study.[164]



RNG, and bioenergy production in general, rely on limited feedstocks that become steadily more expensive as they are consumed. The current RNG market represents the low-hanging fruit, and growth will require tapping higher-cost resources. Further, there is

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[163] This amounts to 380 TBtu. *See* U.S. EIA, *Natural Gas Consumption by End Use Massachusetts*, https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMA_A.htm.

[164] *Future of Gas*, D.P.U. 20-80, Independent Consultant Report Appendix I: Modeling Framework and Assumptions, at 20 (Mar. 2022).

limited potential for pathways that "avoid methane emissions," and ultimately, the bulk of claimed RNG potential stems from sources such as crop residues and energy crops.[165]

Processing biomass feedstocks scales differently from manufacturing solar panels or batteries. In fact, biorefineries gain some economies of scale, but such scale is limited by feedstock availability and transportation distances. These large, complex facilities also experience slower process improvement than manufacturing. While advances in collection and processing may reduce costs, these improvements also benefit superior low-carbon fuel pathways such as sustainable aviation fuel. RNG is already highly subsidized and does not require further piloting or support, especially since additional subsidies may not lower its costs.

Q. Some LDCs claim RNG provides unique, "carbon-negative" life cycle emissions reductions. Is this correct?

No. The characterization of RNG as "carbon-negative" is incorrect and misleading, as it reflects an erroneous understanding of life cycle analysis—one that is being corrected by the California policy that first popularized this misconception.[166] The California Air Resources Board arbitrarily utilized its transportation emissions policy to drive reductions in agricultural emissions—primarily via avoided methane emissions from manure management. The LDCs argue for this expansive approach to life cycle analysis for a

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165 *See Renewable Natural Gas Supply Assessment*, AMERICAN GAS FOUNDATION, at 12, Figs. 4, 13, Table 3 (Jul. 2024), https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf.

166 *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. C, at 42–46.

single fuel pathway—RNG—as it involves crediting of upstream impacts in other emissions sectors.[167] This argument for an expansive use of life cycle analysis opens the door for numerous crediting pathways beyond RNG, including the crediting of upstream (e.g., well-head) emission reductions from electrification's displacement of gas, or the avoided methane associated with an NPA. Such accounting would be administratively challenging and a potentially inconsistent life cycle assessment practice.

Q. Please describe your knowledge of any RNG projects the LDCs have undertaken.

A. Collectively, the LDCs have limited experience with RNG projects. National Grid's New York Affiliate (KEDNY), however, developed an RNG purification system at the Newtown Creek Wastewater Treatment Plant in Brooklyn, which previously flared biogas. National Grid notes that from April 2024 to March 2025, Newtown Creek generated over 271,000 dekatherms ("Dth"), which was corroborated in a recent New York Department of Public Service filing.[168] In response to a question about challenges, National Grid acknowledged "complexities associated with moving mechanical equipment" and "fluctuating RNG prices and RNG market dynamics."[169] These points raise two issues that the LDCs do not articulate in their proposed LCF strategies and are relevant to the

[167] *Berkshire Gas*, D.P.U. 25-40, Exh. BGC-CCP, at 37; *National Grid*, D.P.U. 25-41, Exh. NG-CCP, at 93; *Unitil*, D.P.U. 25-42, Exh. UN-CCP, at 52; *Eversource*, D.P.U. 25-44/45, Exh. ES-CCP, at 180.

[168] *National Grid*, D.P.U. 25-41, Exh. AG-1-11; *see also* NY D.P.S. 23-G-0225, Item No. 182, at 1.

[169] *National Grid*, D.P.U. 25-41, Exh. AG-1-11.

Department's evaluation of the LDCs' proposals: (1) the capital and energy process requirements of RNG and (2) the dynamics of the RNG attribute market.

The process complexities National Grid refers to involve operational challenges with the purification system, resulting in 4,065 hours of downtime (46 percent) and 4,719 hours of uptime (54 percent) during its first year (April 2023–March 2024); only 116,717 Dth was produced, which is less than half of the annual capacity.[170] The project's construction timeline further reflects these difficulties: proposed in 2013 for a 2015 start,[171] the project was not reliably operational until 2024. Between July 2024 and June 2025, uptime improved to 87 percent.[172]

The construction cost of the facility was $56,567,940.[173] Based on 2023-2024 operational data, electricity inputs are 20.4 kWh per Dth or (7 percent energy inputs on a site basis), which is the equivalent of $2.04 per Dth of RNG produced, assuming a $0.1 per kWh industrial electricity cost. This project highlights that RNG requires substantial processing equipment and energy inputs, making it a high-cost energy source. Indeed, the availability

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170 NY D.P.S. 23-G-0225, Item 95 Exhibit H, *National Grid's Purification System Annual Report to NYC DEP* (2024), at 5.

171 Press Release, N.Y.C. Dep't of Env't Prot., *City Announces Innovative New Partnerships that Will Reduce the Amount of Organic Waste Sent to Landfills, Produce a Reliable Source of Clean Energy and Improve Air Quality* (Dec. 19, 2013), https://www.nyc.gov/html/dep/html/press_releases/13-121pr.shtml#.Yk28FxDMJmA.

172 New York City Department of Environmental Protection Biogas to Grid Reporting, https://a826-web01.nyc.gov/BiogasReport/.

173 NY D.P.S. 23-G-0225, Item 95, Exh. H, *National Grid's Purification System Annual Report to NYC DEP*, at 4 (2024).

of RNG-specific environmental attributes makes production possible at these costs. In a revenue forecast, National Grid-KEDNY projected that revenue in 2025 from the sale of 196,165 Dth of gas would generate $637,502 ($3.25 per Dth) in commodity revenue and an additional $5,962,001 in the sales of transportation-sector environmental attributes ($27.14 per Dth).[174]

Q. Is this project contributing to the decarbonization of heat for National Grid's customers?

A. No. At this project, RNG molecules are injected into the local distribution system, which displaces the need for fossil gas to be supplied to the local distribution system. The attributes from this project, however, are sold to an outside party, in compliance with federal and California transportation fuel policy. Indeed, National Grid acknowledges that it sells the attributes and does not claim emissions reductions. This lucrative attribute market poses a significant cost hurdle for incorporating RNG as a heating decarbonization strategy. In fact, this issue arose in Liberty's petition to procure RNG from a Fall River landfill and sell it to its customers on a voluntary tariff, while the RNG producer would generate a Renewable Fuel Standard credit.[175]

Q. Please describe your knowledge of any hydrogen projects the LDCs have undertaken.

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[174] NY D.P.S. 23-G-0225, Item 12, *Newtown Creek Revenue Forecast*, at 711.

[175] *Liberty*, D.P.U. 22-32-C, Order, at 10–11, 17 (Dec. 9, 2022). The Department notes the lack of a Massachusetts structure of attributes, and potential for "deceptive marketing" of claims due to conveyance of multiple attributes.

A. Collectively, the LDCs have limited experience with hydrogen projects, but National Grid notes that the company is participating in a consortium of hydrogen research.[176] In 2021, National Grid's New York Affiliate, unveiled a plan to expand hydrogen production and inject gas into the National Grid gas distribution system to serve approximately 800 homes in New York State.[177] The company subsequently included the project in its initial 2023 rate case proposal, but notes that the project is on hold, and it was not included in the company's final proposal.[178]

Q. Are pipeline LCFs exclusively needed to support customers' decarbonization?

A. No. The Commonwealth offers various avenues for customers to achieve flexibility in their decarbonization efforts. For example, carbon pricing, and alternative compliance mechanisms can, in the near term, provide customers with options that are lower-cost than pipeline LCFs. Policies such as Boston's Building Energy Disclosure Ordinance[179] and MassDEP's Draft Clean Heat Standard Framework[180] focus on mechanisms that eliminate

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

177 National Grid and Town of Hempstead to Develop One of the First Green Hydrogen Blending Projects in the Country, (Dec. 15, 2021), https://www.nationalgridus.com/News/2021/12/National-Grid-and-Town-of-Hempstead-to-Develop-One-of-the-First-Green-Hydrogen-Blending-Projects-in-the-Country/.

178 *National Grid*, D.P.U. 25-41, Exh. AG-1-16.

179 *Ordinance Amending City of Boston Code, Ordinances, Chapter VII, Sections 7-2.1 and 7-2.2 Building Energy and Disclosure (BERDO)* (Dec. 2023), https://www.boston.gov/sites/default/files/file/2023/12/BERDO%202.0%20Final%20Amended%20Docket%200775_1.pdf.

180 *Clean Heat Standard Draft Framework* (Nov. 2023), https://www.mass.gov/doc/chs-draft-program-framework/download.

fuel use and do not include explicit LCF compliance pathways. In lieu of such pathways, an alternative compliance mechanism or payment is levied on residual emissions that are above each policy's specified emission limits, which has the dual benefit of maintaining regulatory simplicity while providing energy customers with a more cost-effective compliance option.

Q. In summary, should the LDCs continue pursuing LCFs, such as RNG or hydrogen, as part of their CCPs?

A. No. Incorporation of RNG and hydrogen is the fastest way to raise customer rates and encourage defections from the gas system, and allowing the LDCs broad recovery for LCFs does not comply with the Department's emissions reductions or affordability priorities.[181] The Department disallowed broad cost recovery of RNG because substantive analysis consistently shows utilization of LCFs to be an inferior decarbonization strategy. The Massachusetts 2050 Roadmap Pathways analysis employed a market-based simulation to demonstrate that it would be preferable to use fossil gas to meet remaining utility gas needs rather than with RNG, and the State's policy development reflects this understanding.

Further, there are considerable economic consequences of utilizing LCFs as opposed to electrification. A $25 supply premium for RNG effectively doubles the cost of gas to residential consumers when factoring in delivery costs, resulting in heat pumps becoming more operationally favorable than utility gas. If RNG were to substitute for fossil gas completely, Massachusetts gas customers would be paying $6.3 billion more in energy

181 G.L. c 25, §1A.

costs based on 2024 consumption levels,[182] or one percent of Massachusetts' GDP. The LDCs have noted that the 2025/2030 CECP evaluates a five percent reduction in the emissions intensity of pipeline gas that would be equivalent to about eight TBtu of RNG demand,[183] which would result in a cost premium of nearly $200 million annually paid to out-of-state suppliers of RNG. The Department should reject the LDCs' LCF proposals.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, but I reserve the right to supplement this testimony should new information become available.

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182 U.S. EIA, *2024 Natural Gas Consumption for Residential, Commercial and Industrial Sectors, 252 BCF*.

183 *2025/2030 CECP*, Appendices, at 159.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

The Berkshire Gas Company	**D.P.U. 25-40**
Boston Gas Company, d/b/a National Grid	**D.P.U. 25-41**
Fitchburg Gas and Electric Light Company d/b/a Unitil	**D.P.U. 25-42**
Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty	**D.P.U. 25-43**
Eversource Gas Company of Massachusetts d/b/a Eversource Energy; and NSTAR Gas Company d/b/a Eversource Energy	**D.P.U. 25-44/45**

AFFIDAVIT OF MICHAEL J. WALSH

Michael J. Walsh does hereby depose and say as follows:

I, Michael J. Walsh, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 17th day of November, 2025.

Michael J. Walsh