Massachusetts D.P.U. 20-80

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The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals

Independent Consultant Report - DRAFT

Part II: Considerations and Alternatives for Regulatory Design to Support Transition Plans

Energy+Environmental Economics

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Contents

Glossary of Terms

ASHP: Air-Source Heat Pump.

BTU or Btu: British thermal unit. 1 BTU = 1,055 joules.

Biomethane: Methane produced from organic matter, through anaerobic digestion or gasification.

Bundled customers: Customers who receive both energy supply and delivery services from their local natural gas distribution utility.

CAGR: Compound Annual Growth Rate.

ccASHP: Cold-Climate Air-Source Heat Pump.

CCS: Carbon Capture and Storage. A process that captures carbon dioxide before it enters the atmosphere and stores it for long periods of time.

CDD: Cooling Degree Day(s). A measurement designed to quantify the demand for energy needed to cool buildings, based on the number of days and number of degrees where the temperature is above 65 degrees Fahrenheit.

CO_2: Carbon dioxide.

Consultants: E3 and ScottMadden.

COP: Coefficient of Performance. A measure of efficiency for a heating or cooling appliance.

CNG: Compressed Natural Gas.

Decarbonization Pathways: Economywide transformations that result in emissions reductions over time, involving replacing end-use appliances with high efficiency models, electrifying end uses, employing efficiency measures, and decarbonizing fuel and electric supplies. Eight such pathways were developed by the Consultants for Massachusetts, all of which achieve the same economy-wide climate goals, i.e., 90% gross GHG reductions and net-zero GHGs by 2050 compared to 1990 levels,[1] as well as interim statutory emissions reduction goals of 50% by 2030 and 75% by 2040.[2]

ERM: Environmental Resources Management. Consultants contracted by the LDCs to facilitate the stakeholder process.

Dunkelflaute: Multi-day periods with sustained low generation from weather-dependent renewables.

D.P.U. or Department: Massachusetts Department of Public Utilities.

D.P.U. 20-80: Docket Number referring to the investigation by the Department of Public Utilities on the role of local gas distribution companies as the Commonwealth achieves its 2050 climate goals.

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[1] Consistent with the 2050 Roadmap, remaining emissions in 2050 are assumed to be netted off by carbon sinks to achieve carbon neutrality by 2050.

[2] Chapter 8 of the Acts of 2021, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy"

E3: Energy and Environmental Economics, Inc. Consultants contracted by the LDCs to investigate decarbonization pathways and the role of gas LDCs.

EIA: The U.S. Energy Information Administration.

ELCC: Effective Load Carrying Capability. A metric used in electric system planning to assess the capacity value (reliability contribution) of a resource.

EJ: Environmental justice.

Embedded gas system costs: The original costs of installed utility plant (physical gas system assets) on the Massachusetts gas distribution system less accumulated depreciation. Embedded gas system costs illustrated in this report refer to the LDCs' aggregate value of rate base.

Energy efficiency: Energy saving measures. In this study, energy efficiency is a foundational component of all decarbonization pathways and include building shell efficiency improvements; electrification; in-kind, high-efficiency replacements; and industrial manufacturing efficiency.

EV: Electric Vehicle.

FERC: Federal Energy Regulatory Commission. An independent agency that regulates the interstate transmission of electricity, natural gas, and oil.

GHG: Greenhouse Gas.

GSEP: Gas System Enhancement Plans. The Gas Leaks Act passed in 2014 permitted gas distribution companies in Massachusetts to submit annual Gas System Enhancement Programs for replacement of aged infrastructure during the following calendar year.[3]

GSHP: Ground-Source Heat Pump.

GSP: Gross State Product. Gross domestic product of a state.

GW: Gigawatt. One gigawatt is equal to one billion (1×10^9) watts.

GWP: Global Warming Potential. Measures the amount of heat a gas absorbs over a given period of time, relative to the heat that would be absorbed by the same mass of carbon dioxide.

HDD: Heating degree day(s). A measurement designed to quantify the demand for energy needed to heat buildings, based on the number of days and number of degrees where the temperature is below 65 degrees Fahrenheit.

Hybrid heat pump: An air-source heat pump that is paired with a gas furnace or fuel oil back-up. The backup can be powered by renewable fuels.

Hybrid electrification: Electrification strategy that combines electric heat pumps with a gas back-up for space heating.

H_2: Hydrogen gas.

[3] See: https://www.mass.gov/lists/gseps-pursuant-to-2014-gas-leaks-act.

Interim 2030 CECP: *Interim Clean Energy and Climate Plan for 2030* developed by the Massachusetts Executive Office of Energy and Environmental Affairs, released in December 2020.[4]

ISO-NE: The Independent System Operator of New England. An independent organization that oversees the operation of New England's bulk electric power system, administers the region's competitive wholesale electricity markets, and manages the regional power system planning process.

Large energy user: Customers that purchase large volumes of natural gas, including large commercial and industrial customers. These customers are usually "delivery only" customers that utilize an LDCs delivery service but procure natural gas separately.

LDCs: The five Massachusetts gas local distribution companies: The Berkshire Gas Company ("Berkshire"), NSTAR Gas Company and Eversource Gas Company ("Eversource"), Liberty Utilities (New England Natural Gas Company) Corp. ("Liberty"), Boston Gas Company ("National Grid"), and Fitchburg Gas & Electric Light Company ("Unitil").

LNG: Liquefied Natural Gas.

Long-term capacity contracts: A pipeline or storage contract that provides firm capacity rights over a long period of time.

kWh: Kilowatt-hour. 1 kWh = 3.6×10^6 joules.

Mass Save: An initiative in Massachusetts designed to provide services, incentives, trainings, and information promoting energy efficiency that help residents and businesses manage energy use and related costs. The initiative is a partnership between the Massachusetts Department of Energy Resources and program sponsors, including Massachusetts' natural gas and electric utilities and energy efficiency providers.

Migrating or non-migrating customers: Gas customers that adopt ("migrating customers") or do not adopt ("non-migrating customers") a decarbonization technology. Migrating customers do not necessarily depart from the gas system under this definition.

Networked geothermal: A shared system of ground-source heat pumps that delivers heating and cooling through a network of pipes.

O&M: Operations and Maintenance.

PRM: Planning Reserve Margin. A metric used in electric system planning to ensure that there are adequate resources to meet forecasted load over time.

Retail choice: Customer choice program that gives customers the option to "unbundle" their natural gas service and purchase natural gas from a natural gas supplier/marketer that is different from the local natural gas utility.

Renewable fuels: Umbrella term referring to renewably produced alternatives to fossil fuels. This includes renewable gases in the distribution system, as well as renewable fuels in the transportation sector.

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[4] See: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.

Renewable gas: Umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system. Renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen and Synthetic Natural Gas (SNG) produced from renewable hydrogen and a climate-neutral source of carbon.

Renewable hydrogen: Hydrogen produced from electrolysis powered by renewable energy.

Roadmap: The Massachusetts 2050 Decarbonization Roadmap study developed by the Executive Office of Energy and Environmental Affairs to explore strategies to reduce emissions and achieve the Commonwealth's climate goals.[5]

ScottMadden: ScottMadden, Inc. Consultants contracted by the LDCs to investigate decarbonization pathways and the role of gas LDCs.

SEP: Stakeholder Engagement Plan developed by the LDCs and stakeholders in the D.P.U. 20-80 process.

SNG: Synthetic Natural Gas. In this study, synthetic natural gas refers to methane that is chemically synthesized from renewable hydrogen and a climate-neutral source of carbon dioxide from biomass or Direct Air Capture.

Therm: Unit of heat energy. 1 therm = 100,000 BTU.

T&D: Transmission and Distribution.

TBTU or TBtu: Trillion BTU.

TRL: Technology Readiness Level.

TWh: Terawatt-hour. 1 TWh = 1×10^9 kWh = 3.6×10^{15} joules.

Utility gas plant: Physical assets owned by LDCs, including mains, meters & services, and storage facilities.

[5] See: https://www.mass.gov/info-details/ma-decarbonization-roadmap.

Executive Summary

This report ("Consultant Report (Part II)") provides recommendations for Local Distribution Gas Companies ("LDC") regulatory designs that support the Commonwealth's achievement of its climate goals. Regulatory support is needed to enable the LDCs to implement strategies relating to transition of the gas system to net zero emissions as well as to mitigate cost and rate impacts on customers, especially low-income and those in environmental justice (EJ) communities.

This report is a companion study to the Consultant Report (Part I), which describes the results of the scenario analysis used to identify decarbonization pathways to achieve the Commonwealth's climate goals in 2050.[6] The regulatory designs in this report were informed by the results of the scenario analysis, including quantitative and qualitative analysis of the decarbonization pathways. Stakeholder feedback was incorporated into the pathways analysis and is reflected in the results. In addition, the regulatory designs were informed by the Department's guidance in D.P.U. 20-80, and the LDC requirements to support the Commonwealth's climate goals as well as their public service obligation to provide safe, reliable, and cost-effective service to customers.

The scenario analysis in Part I identified decarbonization pathways that may be adopted and combined to transition to the Commonwealth's goal of net zero emissions. The pathways share a set of commonalities that are likely part of any decarbonization strategy, while maintaining optionality for longer-term technology advancements. The commonalities include:

- **Energy efficiency** through building shell retrofits and energy efficient equipment, especially for all-electric buildings or buildings using large amounts of decarbonized fuels.
- **Building electrification,** where feasible, including strategies for all-electric residential new construction and hybrid electrification strategies in some existing buildings.
- **Biomethane** from wastes and residues, including from landfill gases. Most scenarios blend up to 5-10% of renewable fuels in the gas distribution pipeline without substantially increasing the cost of gas supply by 2030, to support achievement of the Commonwealth's GHG goals.

The Consultant Report (Part I) concluded: "Balancing across many considerations, decarbonization pathways that strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge. A coordinated gas and electric decarbonization strategy, utilizing a diverse set of technologies and strategies, is likely to be better able to manage the costs and feasibility risks of decarbonization than scenarios that rely more heavily on single technologies or strategies." The regulatory designs in this Report are meant to both support achievement of a coordinated decarbonization strategy as discussed in Part 1 and be applicable to a broader set of pathways, including those with substantial reductions in gas system utilization. This approach is in recognition that there are substantial uncertainties with respect to the course of decarbonization at this stage and that the Department and LDCs will need to maintain flexibility in the face of that uncertainty. Moreover, as stated in the Consultant Report (Part I) the decarbonization pathways are not forecasts, nor do they result in a single preferred solution.

[6] The decarbonization pathways are: High Electrification, Low Electrification, 2030 CECP, Hybrid Electrification, Targeted Electrification, Networked Geothermal, Efficiency Gas Equipment, and 100% Gas Decommissioning. There is a detailed description of the pathways in the Consultant Report (Part I).

Instead, by examining multiple pathways, the analysis is used to identify and compare key features of different plausible futures and their relative costs, feasibility, and risks.

Table 1 (below) summarizes the regulatory designs. The figure shows six regulatory designs, each with an objective and set of recommendations. The recommendations are in large part enhancements to current ratemaking mechanisms. This approach enables the LDCs and the Department to take early action on the strategies recommended in the Consultant Report (Part 1).

In general, regulatory designs 1-3 enable LDC strategies to support the Commonwealth's climate goals, such as increasing adoption levels of electrification and blending renewable gas in the gas system, while regulatory designs 4-6 generally support cost and rate mitigation efforts, such as accelerated depreciation.

Table 1. Proposed Regulatory Designs

Objectives	Recommendations
1. Support customer adoption and conversion to electrified/ decarbonized heating technologies	■ Increase funding of energy efficiency programs ■ Enhance energy efficiency measures ■ Evaluate alternative funding mechanisms ■ Examine electric and gas rate policies to reflect changing demand requirements and cost implications ■ Establish customer service standards and procedures
2. Blend renewable gas in gas-resource portfolios	■ Update Forecast and Supply Plan standards to add renewable gas ■ Provide customers with an option to purchase renewable gas from the LDC ■ Provide customers with an option to purchase renewable gas from third-party suppliers
3. Pilot and deploy innovative electrification and decarbonized technologies, such as renewable gas, to determine their role in the transition	■ Develop standards for review and approval of pilot and R&D programs ■ Design cost recovery mechanisms ■ Track and report on performance metrics
4. Manage embedded infrastructure costs	■ Establish process to review and pre-approve LDC plans for capital investments ■ Develop framework to better optimize infrastructure projects, while maintaining safety and reliability requirements ■ Revise standards for investments to serve new customers ■ Align gas infrastructure cost recovery and utilization
5. Evaluate and enable customer affordability	■ Develop framework to quantify transition costs, including (1) embedded gas infrastructure costs, (2) gas supply portfolio restructuring costs, and (3) other costs, such as workforce transition ■ Evaluate impacts of transition costs on customers, particularly low-income and those in EJ communities ■ Evaluate approaches to recover transition costs, including customers who leave the system and more broadly those who benefit from the transition
6. Develop LDC transition plans and chart future progress	■ Develop schedules for LDC review and approval of transition plans: (1) non-GSEP capital spending, (2) status and changes to transition plans, and (3) metrics to quantify progress ■ Establish planning, investment, and cost recovery framework to optimize gas & electric systems

The scale, timing and nature of the regulatory designs vary by pathway.

The scale of regulatory designs varies by pathway. For example, the need for renewable gas is higher in those pathways that rely more heavily on the gas system. Consequently, regulatory designs related to renewable gas in those pathways that rely more heavily on the gas system, such as the Efficient Gas Equipment pathway, require more immediate attention and expansive action, such as updating forecast and supply plans to add significant blending of renewable gas and implementing tariff options for customers to purchase renewable gas from the LDCs and third-party suppliers.

The timing of the regulatory designs varies by pathway. For example, regulatory designs that address customer affordability concerns – particularly those related to LDC delivery rates – require more immediate action under some pathways than others. The magnitude of LDC delivery rate increases under the 100% Gas Decommissioning pathway, for example, are more significant than those under the Efficient Gas or Low Electrification pathways. Consequently, regulatory designs related to affordability in the 100% Gas Decommissioning pathway, for example, require more immediate attention and action, such as quantifying transition costs and evaluating approaches to recover transition costs more broadly than LDC customers, such as in a manner that reflects the benefits of achieving the Commonwealth's climate goals.

The nature of the regulatory designs varies by pathway. Regulatory designs likely require a combination of Department approval or directive and new legislation. Some regulatory designs, such as updates to the forecast and supply plan and approving a new tariff to offer customers the option to purchase renewable gas, likely fall within the Department's authority. By comparison, approval of other regulatory designs, such as a financial transfer between electric and gas systems, likely fall outside of the Department's authority. Similarly, broader fuels initiative such as incorporation of minimum levels of renewable fuels across the State including in heating oil and propane, would likely need to be done in the context of a broader legislative initiative.

The Consultant Reports (Part I and Part II) provide to the Department, the LDCs, and stakeholders a range of pathways, common strategies, and recommendations regarding regulatory design changes. The regulatory designs also include a process to review LDC progress toward the climate goals, while providing opportunities for modifications to LDC transition plans and regulatory solutions. Overall, the regulatory designs recommended in this report represent a meaningful step toward supporting the Commonwealth's achievement of its climate goals while mitigating cost and rate impact on customers and maintaining optionality for LDCs and customers.

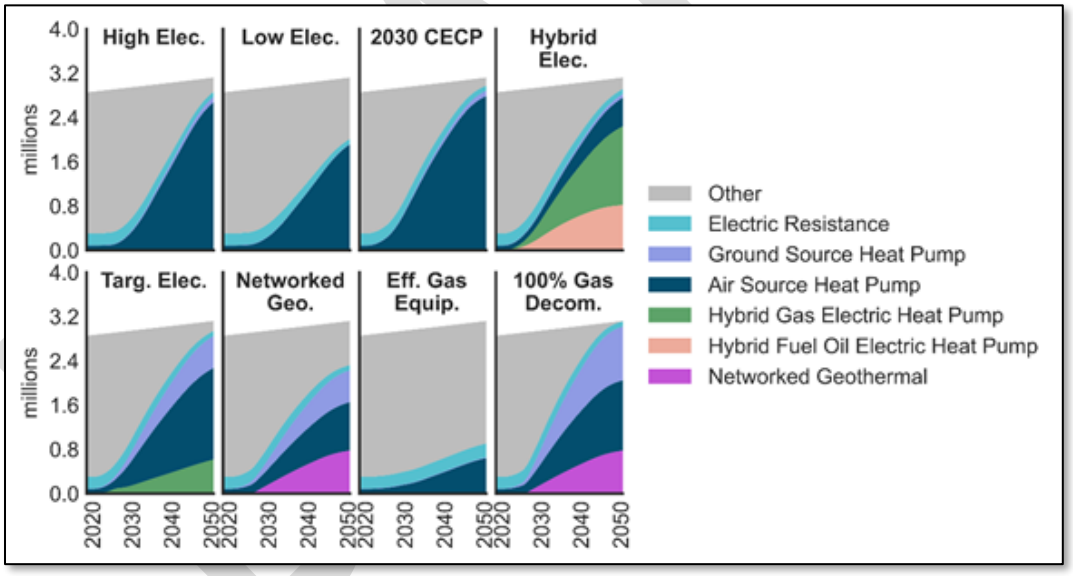
1. LDC Strategies Supporting the Commonwealth's Climate Goals

The Consultant Report (Part 1) describes eight pathways to support the Commonwealth's climate goals. The pathways share a set of commonalities that are likely part of any decarbonization strategy, while keeping optionality for longer-term technology advancements. These commonalities include (1) Increased adoption of electrification and decarbonization technologies, (2) blending of renewable gas in the gas system and (3) expansion of energy efficiency programs and funding – each of which is discussed in more detail below.

1. Increased Adoption of Electrification and Low-Carbon Technologies

The pathways analysis concludes that significant levels of customer adoption of electric and low-carbon heating technologies are needed to support the Commonwealth's climate goals, as shown in Figure 1 (below). The technologies include air- and ground-source heat pumps, hybrid gas-electric heat systems, network geothermal systems, and efficient gas equipment such as gas heat pumps.

Figure 1. (Recreated from the Consultant Report, Part I). Residential Space Heating Stocks by Pathway, Emphasis on Electrification. A full overview of space heating stock conversions is provided in Appendix 1.



Presently, there is limited adoption of these technologies, primarily due to the higher upfront equipment and installation costs and limited customer awareness, education, and incentives for the technologies. In addition, heating equipment is typically replaced only on an as-needed basis, generally every 16 to 30 years.[7]

The Consultants recommend the LDCs support increased adoption of electrification and low-carbon technologies by developing, deploying, and promoting programs that expand customer

[7] https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf

awareness, education, and incentives in the technologies. The Consultants recommend building on programs already included in the LDC's three-year Energy Efficiency Plan.[8]

The Consultants also recommend the LDCs pilot and deploy electrification and low-carbon technologies to evaluate from a research and development perspective what role the technologies might play in supporting the Commonwealth's climate goals. These technologies have the potential to avoid gas infrastructure investments through coordinated planning and optimization of the gas and electric systems.

One such pilot opportunity is networked geothermal systems. These systems can be utilized as an alternative to gas heating systems. Since the technology does not utilize the gas infrastructure, networked geothermal systems have the potential to be used as strategic replacements for gas infrastructure investments. As such, networked geothermal systems offer LDCs the potential to reduce greenhouse gas emissions, avoid gas infrastructure investments, and leverage LDC's expertise and workforce in designing, building, operating, and maintaining the networked geothermal systems.

Presently, there are many uncertainties regarding the role that networked geothermal systems can play in supporting the Commonwealth's climate goals, including overall feasibility of these systems and long-term costs. As a result, the Consultants recommend the LDCs develop pilot opportunities for networked geothermal systems to evaluate the technology as an alternative method to deliver heating service to customers while potentially minimizing or avoiding pipeline replacement projects. Pilot opportunities for networked geothermal systems, such as the projects approved for Eversource and National Grid, would better inform LDC decarbonization strategies and proposals as well as customer cost implications.

A second pilot opportunity is network optimization using hybrid heating systems. Hybrid heating systems are combination gas and electric heating systems that have the potential to support the Commonwealth's climate goals by utilizing electric heat while potentially avoiding or minimizing electric system investments. Specifically, hybrid heating systems utilize gas heat during extreme winter weather conditions and electric heat during all other times of the year. This approach leverages the existing gas system while potentially avoiding or minimizing electric system investments, consistent with the Consultant Report (Part 1) conclusions. The Consultants recommend LDCs develop pilot opportunities to better characterize the operations of hybrid heating systems as a potential strategy to support decarbonization while potentially avoiding or minimizing electric system investments.

The list of potential pilot programs is not limited to networked geothermal or hybrid heating systems but could include other low-carbon technologies, such as gas heat pumps and others that may arise over the coming decades.

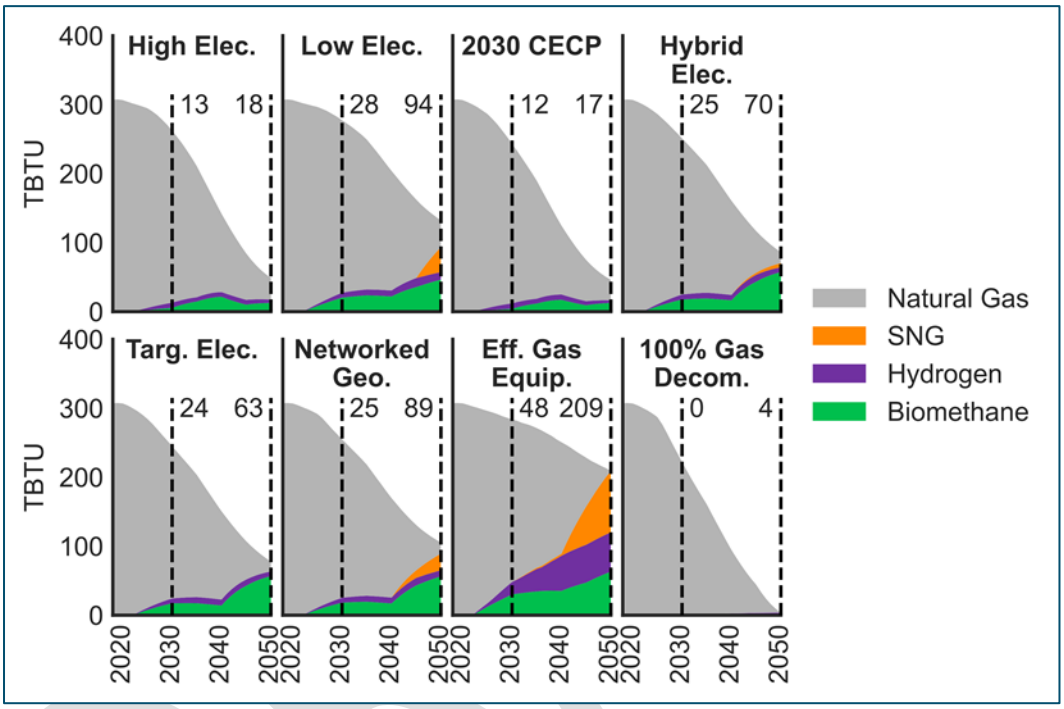
2. Supply and Procurement of Renewable Gas

As described in the Consultant Report (Part 1), to achieve the Commonwealth's climate goals, the pathways rely on various levels of renewable gas as shown in Figure 2 (below). Renewable gas includes biomethane (sometimes called Renewable Natural Gas (RNG)), green hydrogen and

[8] D.P.U. 21-120 – D.P.U. 21-129, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14461268

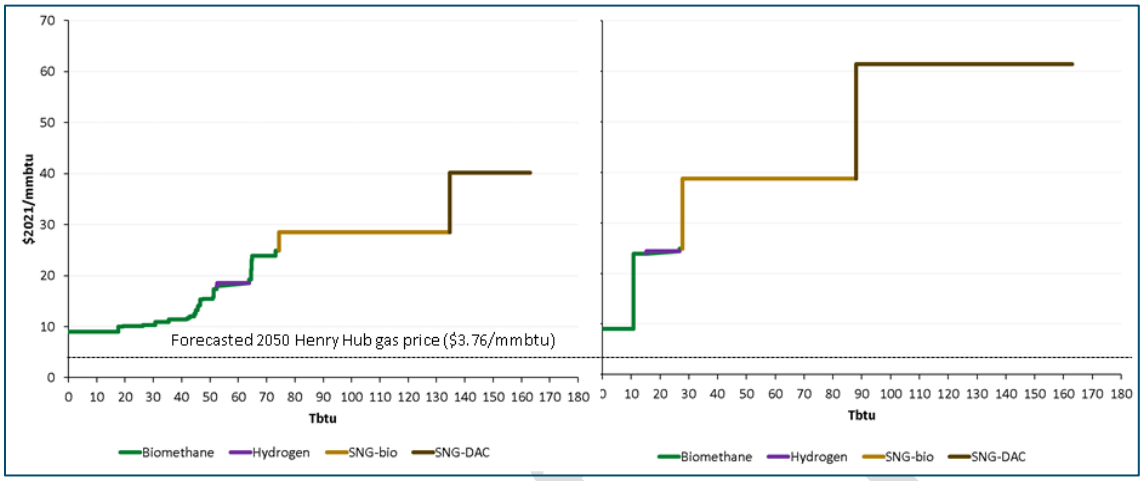
Synthetic Natural Gas (SNG) produced from the combination of green hydrogen and carbon sourced from biomass or direct air capture. The pathways analysis shows that renewable gas is likely needed to support the Commonwealth's climate goals, even in scenarios with high levels of building electrification. Most pathways assume a blending of renewable gas of 5% to 10% percent by 2030. Longer term, renewable gas is a larger portion of the gas supply by 2050 in many of the pathways evaluated.

Figure 2. (Recreated from the Consultant Report, Part I). Blending of Renewable Gases



Presently, there is limited utilization of renewable gas, primarily due to (i) current LDC planning standards that rely on a "least cost" planning criterion, and (ii) the higher cost of renewable gas relative to pipeline gas, as shown in Figure 3 (below).

Figure 3. (Recreated from the Consultant Report, Part I) Overview of Renewable Gas Supply Curve. 2050 costs for the Optimistic (left) and Conservative (Right) case for the Efficient Gas scenario.



The Consultant Report (Part 1) recommends LDCs develop a procurement strategy to add renewable gas supply to the resource portfolio, particularly related to biomethane or RNG. A near-term target could start with a 5% blend of RNG and then increase gradually based on bill impact and customer affordability considerations. The Consultants recommend a procurement strategy that includes customer education and marketing to facilitate customer understanding of the benefits and cost implications of the renewable gas and their options to incorporate it into their fuel mix.

In addition to early action regarding RNG blending, the LDCs should investigate other forms of renewable gas, including hydrogen and SNG produced from green hydrogen combined with carbon from biomass or direct air capture, and participate in R&D opportunities related to their development and commercialization.

3. Expansion of Energy Efficiency

The Consultant Report (Part 1) concludes that an expansion of energy efficiency programs, such as building retrofits, envelope efficiency, and energy efficient equipment, are needed to achieve the Commonwealth's climate goals, particularly in all-electric buildings or buildings using large amounts of decarbonized fuels. The expanded energy efficiency measures not only reduce demands on the electric system, but also reduce demands on the gas system and the need to purchase renewable gas for hard-to-electrify equipment.

Specifically, the pathways analysis in the Consultant Report (Part 1) suggests a reduction in final energy demand in the residential and commercial sector between 41% and 50%, primarily driven by fuel switching and building shell improvements. As such, expanded energy efficiency is a common strategy across the pathways in support of the Commonwealth achieving its climate goals.

2. Considerations in Developing the Regulatory Designs

The regulatory designs discussed here are informed by several considerations that include (1) the Consultant Report (Part 1) recommended strategies, (2) the Department's guidance in D.P.U. 20-80, (3) the LDC's continuing obligations to provide safe, reliable, and cost-effective service, and (4) the Consultants' recommendation for early action on decarbonization strategies. The Consultants believe early action is important to clarify the role that decarbonization strategies can play in supporting Commonwealth's climate goals and to help ensure the strategies can scale with the timelines defined by the pathways analysis (which in-turn are driven by the Commonwealth's goal).

1. Consultant Report (Part 1) Recommended Strategies

The Consultant Report (Part 1) recommended certain LDC strategies to support the Commonwealth's climate goals. Regulatory support is needed to enable these LDC strategies.

The strategies are summarized in table below.

Table 2. Recommended LDC strategies (Consultant Report, Part I)

Recommended strategies for LDCs
1. Develop procurement strategies for decarbonized gases.
2. Investigate opportunities for hydrogen blending and synthetic gas R&D.
3. Develop R&D and pilot opportunities for networked geothermal systems, including opportunities for strategic GSEP replacements.
4. Promote adoption of energy efficiency measures such as building shells and efficient equipment via funding and customer education.
5. Promote adoption of building electrification, including hybrid strategies, via funding and customer education.
6. Investigate opportunities for gas system cost savings through targeted electrification pilots.
7. As applicable, promote cross-company coordination to achieve an integrated gas & electric approach to decarbonization.
8. Protect customers, particularly low income and customers in EJ regions, from rate shocks by evaluating decarbonization-specific rate structures.
9. Work collaboratively with communities to develop decarbonization plans that support low-income communities and prioritize equity.
10. Develop decarbonization evaluation metrics, and actively monitor customer migrations and potential impacts to gas planning.

2. The Department's Guidance

The Department provided a set of objectives for regulatory support; namely, to support the Commonwealth's climate goals while maintaining the LDC's obligation to provide safe, reliable, and cost-effective service. The Department's guidance was provided in its order in D.P.U. 20-80. Specific guidance included:

- "Specifically, we will explore strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth."
- "For all identified pathways, the Department will endeavor to determine whether and how LDCs can implement each pathway in a cost-effective way with a continued focus on safe and reliable service to their ratepayers."
- "[w]e direct each LDC to submit a proposal to the Department that includes the LDC's recommendations and plans for helping the Commonwealth achieve its 2050 climate goals supported by the Report."

Guidance was also provided through specific directives in the order, including evaluation of costs, discussion of qualitative factors, and development of proposed recommendations to reduce GHG emissions. [9]

3. LDCs Continued Obligation to Provide Safe, Reliable, and Cost-Effective Service

The regulatory designs are also informed by the LDCs continuing obligation to provide safe, reliable, and cost-effective service. The LDCs have an obligation to serve existing customers. Accordingly, the LDC gas distribution system will need to be maintained to provide safe and reliable service to customers who choose to remain on the system. In addition, the LDCs will be required to procure gas supplies, including contracts on upstream pipelines, to reliably provide service to customers that remain on the system. Finally, LDCs continue to have obligations and requirements related to installation, maintenance, and operations of gas pipelines, including Department of Transportation requirements.

4. Early Action on Regulatory and Policy Changes to Support the Climate Goals

The regulatory designs discussed here are informed by the overall conclusion in the Consultant Report (Part 1) that the scale, timing, and nature of regulatory support will depend on the decarbonization strategies that are ultimately deployed in Massachusetts. However, regulatory support is needed for decarbonization strategies in all pathways, as summarized in the conclusion.

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[9] Specifically, the Department stated the following directives:

"(1) The evaluation of costs shall include the following (a) a discussion of possible mechanisms, methodologies, or policies to address the recovery of costs or responsibility for cost incurrence as well as mitigate of costs and impacts for customers, particularly low-income customers…"

"(2) Present a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing. "

"(3) Develop proposed recommendations to reduce GHG emissions from the sale and distribution of natural gas to meet applicable goals in relation to the Roadmaps, with specific initiatives, actions, and interim milestones."

The Consultant Report (Part 1) recommends that the LDCs, together with the Department, take early action on decarbonization strategies and start implementation of “no regrets” regulatory designs in support of the Commonwealth’s climate goals.

3. Regulatory Design Recommendations

Based on the LDC strategies discussed above, the Department's guidance in D.P.U. 20-80, the need for early action supporting the Commonwealth's climate goals, and the LDC's continuing obligation to provide safe, reliable, and cost-effective service, the Consultants recommend the following regulatory designs:

1. Support adoption and conversion to electrified / decarbonized heating technologies
2. Blend renewable gas in gas-resource portfolios
3. Pilot and deploy innovative electrification and decarbonized technology programs to help determine their role in the transition
4. Manage embedded infrastructure costs
5. Evaluate and enable customer affordability
6. Develop LDC transition plans and chart future progress

1. Support Customer Adoption and Conversion to Electrified / Decarbonized Technologies

As discussed earlier, the Consultant Report (Part I) concludes that significant levels of customer adoption of electrification and decarbonization technologies are needed to meet the Commonwealth's climate goals. To achieve these levels, the Consultants suggest that the Commonwealth needs to provide sufficient consumer education and incentives, particularly among low-income customers and those in EJ communities. In addition, customers will need support from qualified contractors to encourage and facilitate adoption of the technologies.

Certain pathways, such as High Electrification, require early action to increase customer adoption, while other pathways, such as Efficient Gas or Low Electrification, provide more lead time for program development, customer outreach, testing or piloting of technologies, and planned and structured regulatory engagement. Pathways that have a faster pace of adoption require early action by LDCs and regulators to develop, review, approve, and implement decarbonization programs. The early actions include programs that shift consumer economics in favor of electric technologies.

Presently, consumer education and incentives are available to Massachusetts gas and electric customers through the Mass Save program, including for gas and electric energy efficiency measures as well as electrification technologies such as heat pumps.[10] However, the scope and scale of adoption in the pathways are well beyond the levels envisioned in the current program.

Specifically, as discussed in Consultant Report (Part I), the demand-side capital investments required for building appliances and shell upgrades are substantial across all pathways, reaching between $73 and $97 billion cumulative between 2020-2050. It is unlikely that these costs can be carried solely by households, particularly low- and moderate-income ones. Therefore, achieving deep decarbonization, regardless of the pathway pursued, will likely require additional consumer

[10] https://www.masssave.com/

incentives similar to the incentives currently offered through Mass Save.[11] Regulatory designs are needed to expand the scope and scale of the current programs.

The number of heat pumps under the decarbonization pathways are shown in Figure 4 below.

Figure 4. (Recreated from the Consultant Report, Part I). Number of Residential homes with heat pumps or electric heating by pathway (includes hybrid heat pumps, networked geothermal systems, and gas heat pumps).

in millions	2020	2025	2030	2035	2040	2045	2050
High Electrification	0.3	0.3	0.6	1.2	1.8	2.5	2.9
Low Electrification	0.3	0.3	0.5	0.9	1.3	1.7	2.0
Interim 2030 CECP	0.3	0.5	1.0	1.7	2.3	2.7	3.0
Hybrid Electrification	0.3	0.5	1.0	1.7	2.2	2.6	2.9
Networked Geothermal	0.3	0.4	0.9	1.4	1.8	2.2	2.3
Targeted Electrification	0.3	0.5	1.1	1.7	2.2	2.7	2.9
Efficient Gas	0.3	0.3	0.4	0.6	1.0	1.4	1.8
100% Gas Decommissioning	0.3	0.4	1.1	1.9	2.5	2.9	3.1

Regulatory Designs

The Consultants recommend five regulatory designs to support the significant levels of customer adoption of electrification and decarbonized technologies.

1. **Increase funding of energy efficiency programs**

Increased funding of energy efficiency programs would help support the significant level of customer adoption of electrification and decarbonized technologies in the pathways.

The electric and gas LDCs' energy efficiency plans (Mass Save program) have already begun to increase the level of customer adoption of energy efficiency and decarbonized technologies. On November 1, 2021, the Mass Save Program Administrators (PA)[12] filed the 2022-2024 Energy Efficiency Plan which continues to prioritize electrification along with equity and workforce development.[13] On January 31, 2022, the Department approved the 2022-2024 plan, subject to Department approved modifications.[14] The approved energy efficiency programs are designed to contribute their share of GHG emissions reductions to achieve 2030 GHG emissions reduction targets and continue progress towards net-zero emissions by 2050.

Depending on the decarbonization pathway adopted by the Commonwealth, the funding for energy efficiency and electrification programs may need to be further expanded. The Interim 2030 CECP pathway, for example, requires an average of approximately 80,000 heat pump installations

[11] It is important to note that the cost figures shown here represent levelized costs, not upfront customer costs. As described in Text Box 2 in Part I of the Report, upfront costs for heat pumps alone up to 2030 are likely to involve upfront customer costs of >$0.5 billion per year. For comparison, the approved budget for the 2022-2024 statewide energy efficiency plan, which includes the Mass Save program, is approximately $4 total for three years, $1.8 bln of which reserved for participant incentives, an average of $0.6 billion per year.

[12] The Berkshire Gas Company, Fitchburg Gas & Electric Light Company d/b/a Unitil, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, Massachusetts Electric Company, Nantucket Electric Company, Boston Gas Company and former Colonial Gas Company, each d/b/a National Grid, NSTAR Electric Company, NSTAR Gas Company and Eversource Gas Company of Massachusetts, each d/b/a Eversource Energy, and Cape Light Compact JPE.

[13] D.P.U. 21-120 – D.P.U. 21-129, Three-Year Plan 2022-2024 (filed November 2021)

[14] D.P.U. 21-120 – D.P.U. 21-129, 'Order' (January 31, 2022)

per year between 2022-2030, combined with weatherization measures such as energy retrofits and building envelope efficiency. In 2019, less than 4,000 heat pumps were installed per year in the Commonwealth as recorded by the MassSave program. In addition, to ensure equitable access, heat pump and energy efficiency deployments for low-income customers would also need to be expanded. The scale of funding needed to support the magnitude of electrification, with equitable access, is significant and will need to be evaluated.

The expanded funding for the energy efficiency programs can be approved as part of gas and electric energy efficiency plans. Updates to, or augments of, the currently established energy efficiency planning process would facilitate early LDC actions on decarbonization initiatives, since program standards, funding mechanisms, and reporting structure are already in place.

2. Enhance energy efficiency programs to better support decarbonization

The pathways require deployment of new strategies and technologies. These include neighborhood-scale deployment of technologies, such as targeted electrification and networked geothermal. However, because these strategies require customer groups rather than individual customers to convert from natural gas to an alternative energy technology, energy efficiency programs may need to be enhanced to support the new strategies, such as a more targeted, higher incentive offered to a neighborhood group. The cost-effectiveness criteria for such programs would need to consider the benefits of potentially avoiding gas system infrastructure costs in geographically targeted areas.

Enhancements are needed in all aspects of the programs, including customer education, awareness, and adoption of decarbonization strategies and technologies. The enhancements will also include other market transformation initiatives targeted at contractors, distributors, and manufacturers of electrification technologies (e.g., midstream incentives and training programs). Some of these activities are already underway as part of the approved 2019-2021 Three Year Plan.

3. Evaluate alternative funding mechanisms

The higher funding levels needed to support an expanded and enhanced energy efficiency program provide an opportunity to evaluate and update funding mechanisms. Presently, energy efficiency programs are funded through the energy efficiency surcharge (EES) included in the Local Distribution Adjustment Clause (LDAC). One approach is to continue to fund the programs through the EES. This approach facilitates early action of LDC strategies, as described earlier.

However, the current approach does not necessarily align the benefits and cost responsibility for certain programs. Hybrid heating systems, for example, provide benefits to the electric system by avoiding or mitigating increases in winter peak requirements. Under the current approach, however, the LDC customers pay for the cost of program. In addition, the scale of funding needed to support the decarbonization strategies may broader sources of funding than LDC customer bills. The Consultants recommend evaluation of the funding mechanism to review alignment of benefits and cost responsibility of the energy efficiency program as well as the likely need for broader sources of funding.

Presently, Hydro-Quebec (HQD) and Energir have an ongoing “dual energy” agreement in which gas customers in targeted market areas are converted to electricity to operate on electric heat during non-winter peak periods while operating on gas heat during winter peak periods. The agreement was driven by the Quebec government’s Green Economy 2030 Plan that calls for a 50%

percent reduction in the GHG emissions from building heating. The agreement also includes an innovative benefit-sharing mechanism which would allow for a semi-annual financial transfer from HQD to Energir as compensation for their role in electrification. [15]

Similar to the HQD-Energir example, a portion of the cost savings from hybrid electrification could be used to support the ongoing utilization of the gas system. In Part I, the Consultants identified that the Hybrid pathway reduces median peak demands by 15 GW relative to the High Electrification Pathway. On a per-customer basis, this is equal to approximately 6 KW of peak demand savings during a typical year, with higher savings achieved during extreme conditions. Assuming the same electric capacity costs used in Part I, the gas system therefore creates over $1,200 per hybrid customer in electric system value annually in the Hybrid and Targeted Electrification scenarios, or nearly 2/3 of the gas revenue requirement per customer in that scenario. Those benefits could be shared between electric and gas systems through regulatory changes that reflects the electric sector value created by utilization of the gas system.

4. **Evaluate restructuring electric and gas rates**

   a. **Restructure electric rates**

The significant levels of adoption of electrification and decarbonized technologies provides an opportunity to examine electric rate design policies. Specifically, the pathways analysis shows that adoption of electric heating systems shifts electric system peak demands from the summer to winter. The shift in peak demand provides an opportunity to evaluate price signals associated with the electric rates. The evaluation could, for example, examine time variant rates that reflect the cost of serving higher electric demands in the winter. In addition, the evaluation could examine the critical peak pricing rates that reflect the cost of serving higher electric demands under extreme winter weather conditions, similar to Oklahoma Gas & Electric's (OG&E's) critical peak pricing (CPP) program that sets prices for extreme summer conditions.[16] CPP rates reflect the substantially higher cost of generation, transmission, and distribution facilities to meet CPP conditions – providing customer with a significant incentive to reduce demand during such conditions.

In the context of the pathways analysis, particularly Hybrid Electrification, CPP rates could provide an economic incentive for customers to install hybrid heating (i.e., continue to leverage existing gas or oil heating) rather than all-electric heating systems, thus reducing the cost of meeting customer electric peak demands especially under extreme winter weather conditions.

   b. **Restructure gas rates**

The significant levels of adoption of electrification and decarbonized technologies provides an opportunity to examine gas rate design policies. Customers with hybrid gas-and-electric heating systems have substantially different demand characteristics than those with traditional gas heating systems. Hybrid gas-and-electric heating systems utilize electric heat on all but the coldest days of the year at which point they switch and utilize gas heat. By comparison, traditional gas heating

[15] Case No: D-2021-172 File R-4169-2021 Phase 1, "Demande Relative Aux Mesures De Soutien À La Décarbonation Du Chauffage Des Bâtiments," Regie De L'Energie (September 2021) http://publicsde.regie-energie.qc.ca/projets/597/DocPrj/R-4169-2021-B-0003-Demande-Dem-2021_09_16.pdf#page=5.

[16] For more details on OG&E's programs to reduce peak demands through time-variant rates, see: 'OG&E Uses Time-Based Rate Program to Reduce Peak Demand' U.S. Department of Energy (April 2013) https://www.smartgrid.gov/files/documents/OGE_CBS_case_study.pdf.

systems utilize gas heat throughout the year. The unique demand characteristics of hybrid heating systems drive unique cost characteristics since customers with hybrid heating systems utilize the gas system for only the coldest days of the year.

One possible approach to address the unique demand and cost characteristics of hybrid heating systems is to establish a separate "hybrid" rate class for those customers. The "hybrid" rate class would have a unique set of rates that reflected the cost associated with providing service only during winter peak periods. This approach would address the basic misalignment between "hybrid" customer rates and their cost of service.

Presently, LDC costs are largely fixed and do not change with changes in usage. LDC rates, by comparison, are largely variable and recovered through usage charges.[17] Thus, as customer usage declines, which would be the case for hybrid heating systems, LDCs would tend to under collect the cost of serving the hybrid heating customer. Costs not collected from hybrid heating customers are then collected from all other customers through the revenue decoupling charge.

There are a few rate structures that would improve alignment between the LDC rate and cost of service for each hybrid heating customer. One approach is to increase the customer charge. However, this approach would not differentiate between high-use and low-use customers, creating cross-subsidies. Another approach would be to implement a demand charge. This approach would differentiate between high-use and low-use customers but may create a barrier to customer adoption of the hybrid heating system. A third approach would be to recover the costs not collected from the hybrid heating customers from the electric utility. The rationale for this approach is the electric utility receives benefits from hybrid heating customers while avoiding or minimizing electric system investments to serve the customers. This approach is consistent with the approach adopted by Hydro-Quebec (HQD) and Energir.

c. Revenue decoupling

Presently, LDCs have a revenue decoupling mechanism that is designed to recover or refund differences between actual and Department-authorized revenues.[18] The revenue decoupling mechanism is currently designed on a "per customer" basis, enabling the LDCs to retain the incremental revenues associated with serving new customers to offset the incremental costs until rates are reset. The mechanism has worked well in the past since the LDCs historically experienced an increase in customers. However, the decarbonization pathways result in service to fewer customers over time; thus, a revenue decoupling mechanism designed on a "per customer" basis no longer ensures that the LDCs will recover the Department-authorized revenues.

An approach to address this is to revise the revenue decoupling mechanism from a "per customer" reconciliation of actual and authorized revenues to a reconciliation of total revenues. This approach is currently in place for Massachusetts electric utilities.[19] [20] Under this approach, the LDCs

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[17] LDC rates do have a fixed component through the customer charge; however, the variable component in most cases recovers most of the LDC revenue requirement.

[18] D.P.U. 07-50-A, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9299693

[19] https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/60-tariff-ma.pdf?sfvrsn=3e23c062_10

[20] We note that the Department has recently directed the electric distribution companies to file in their next base rate proceedings for discontinuance of full revenue decoupling to remove disincentive to pursue strategic electrification. (D.P.U. 21-120 – D.P.U. 21-129, 'Order' (January 31, 2022))

reconcile actual revenues and Department-authorized or target revenues rather than revenues per customer and reconciliation would include revenue from new customers. A second benefit is to support better financial alignment between LDC incentives and climate policy objectives.

5. **Establish customer service standards & procedures for decarbonization initiatives**

New strategies to increase adoption of electrification and decarbonization technologies provide an opportunity to examine customer service standards and procedures. There are certain strategies, such as geographically targeted electrification, that require updating of customer service standards and procedures. Geographically targeted electrification, for example, necessitates that all customers within a specific area to convert from gas heating to electric heating or another heating source, such as networked geothermal. The conversion requirements raise issues on how the changes would be implemented, particularly related to customer choice, cost incurrence, timing requirements and protections. Below are the types of issues that would need to be addressed.

- Customer education, communication, decision process and timeline
  - What is the process and timeline for customer communications, education, and decisions?
- Customer Options
  - What choices are available to customers?
  - Do the customers opt-in to electric service?
  - Do the customers opt-out of gas service?
  - What if not all customers agree to convert to electric?
  - Under what circumstance will gas service be terminated?
- Financial support
  - What customer incentives and rebates are available to facilitate the switch?
  - What low-interest loans are available to facilitate the switch?
  - How will customers with recently purchased equipment be compensated?
- Logistical support
  - What customer support is available to facilitate the switch?
  - How can customer education and communication address EJ populations (e.g., English Isolation)?
  - How can access to and engagement of contractors be improved?

2. Blend Renewable Gas Supply in Gas-resource Portfolios

As discussed earlier, the Consultant Report (Part 1) recommends LDCs develop a procurement strategy to add renewable gas supply to the resource portfolio. Blending limited amounts of renewable gases into the pipeline results in a reduction of GHG emissions without substantially increasing gas costs. The Consultants recommend the LDCs develop procurement strategies for renewable gases, starting with relatively low-cost resources. Early actions include investigating the deliverability of biomethane, hydrogen and synthetic gases from a broader range of sources and regions. Early actions on these fuels could help to further clarify their role in supporting the state's

decarbonization goals and to ensure these fuels can scale within the timelines (between 2030 and 2040) identified in the pathways.

Presently, renewable gas does not meet the Department's "least cost" supply planning standards. In addition, as outlined in the Consultant Report (Part 1), the higher cost of renewable gas raises customer affordability concerns as LDC rates will be higher than they otherwise would be utilizing pipeline gas.

As discussed in the Consultant Report (Part I), increasing the level of blending of renewable gases into the gas system is also consistent with policies currently proposed in Massachusetts. For example, an investigation of heating fuel emissions cap was established by the Interim 2030 Clean Energy and Climate Plan (CECP) released December 2020 through a special Commission on Clean Heat.

Regulatory Designs

The Consultants recommend four regulatory designs to enable LDCs to incorporate renewable gas supply into the gas system.

1. **Update the Forecast and Supply Planning standards to add renewable gas**

There are two potential approaches to update supply planning standards to add renewable gas to the gas system: (1) require a minimum level of renewable gas in the gas system, and (2) incorporate the cost of carbon in the supply planning economic analysis.

Set minimum level of renewable gas

The first approach sets a minimum level of renewable gas in the gas system. This can be accomplished through a Renewable Heating Fuel Standard (RHFS) or a Renewable Portfolio Standard (RPS), similar to what is used in the electric industry. The requirement could be extended to third-party suppliers who provide service through retail choice programs.

The minimum level of renewable gas could be set low initially to address potential supply availability, cost, and/or customer affordability considerations – and then increased gradually subject to these considerations. The requirement also could be subject to performance incentives that might include a credit for environmental attributes, such as a "Low Carbon" fuel credit.

The RHFS or RPS could be authorized by the Department through a generic proceeding on gas supply planning standards applicable to all LDCs or an LDC-specific gas forecast and supply planning proceeding. Alternatively, the RHFS or RPS could be authorized by the legislature as part of a collective process with other fossil fuel suppliers, such as heating oil and propane suppliers.

Presently, a variation of this approach is in place in Oregon[21] and Denmark.[22] In Oregon, the legislation sets voluntary RNG targets initially set at 5% of total portfolio in the first five years and increasing by 5% in five-year increments up to 30% by 2050. In Denmark, twenty-five percent of

[21] 'Senate Bill 98', State of Oregon, https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/SB98/A-Engrossed

[22] 'Accelerating Green Energy Towards 2020' Danish Ministry of Climate, https://ens.dk/sites/ens.dk/files/EnergiKlimapolitik/accelerating_green_energy_towards_2020.pdf

fuel in the gas system is renewable natural gas. The level was achieved over approximately 10 years.[23]

Add a cost of carbon to the supply planning economic analysis

The second approach adds a cost of carbon (or equivalent pricing mechanism) to the supply planning economic analysis. The approach would provide an economic advantage to low-carbon supplies. The cost of carbon could be set low initially to address potential supply availability, cost, or customer affordability considerations – and then increased gradually subject to these considerations.

Presently, the LDCs incorporate social cost of carbon in cost-effectiveness tests for the energy efficiency programs. The social cost of carbon for EE and DSM cost-effectiveness tests is also incorporated in other states such as Colorado and New York.

Under either approach, the cost of the renewable gas would be recovered through the Cost of Gas Adjustment Clause (CGAC), similar to costs for any other supply resource.

2. Provide customers with an option to purchase Renewable gas from the LDC

Some customers may prefer to have a higher proportion of renewable gas than incorporated into the gas system. The LDCs could provide customers with an option to purchase renewable gas at various blends, such as 10% or 100% renewable gas. This approach might be appealing to those customers who have strategic goals to reduce their carbon emissions.

The tariff service could be approved by the Department through a generic proceeding applicable to all LDCs and/ or through LDC-specific rate setting proceeding.

Presently, this service is offered by Vermont Gas, where customers can select a specific blend of renewable gas. [24]

3. Renewable gas from third-party suppliers

Provide customers with an option to purchase renewable gas from third-party suppliers via an LDC delivery service. This approach might be appealing to those customers, especially large commercial and industrial customers, who wish to purchase directly from a third-party renewable gas supplier. The LDC would provide delivery service from the third-party supplier to the customer.

The tariff service could be approved by the Department through a generic proceeding applicable to all LDCs and/ or through LDC-specific rate setting proceeding. The service may need to consider interconnection requirements, such as those described in the Northeast Gas Associations report on Interconnection Guide for Renewable Natural Gas in New York State.[25]

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[23] 'New Record for Biogas in the Gas System in 2021', Energinet (January 2022), https://en.energinet.dk/About-our-news/News/2022/01/07/New-record-biogas

[24] 'Renewable Natural Gas' Vermont Gas, https://www.vermontgas.com/renewablenaturalgas

[25] https://www.nationalgridus.com/media/pronet/nga-interconnect-guide-for-rng-in-nys.pdf

Presently, this service is offered by the California gas utilities, where customers can select from a list of suppliers.[26]

Applicable to all these designs, the Consultant recommends a procurement strategy that includes customer education, marketing, and incentives that promote integration of decarbonized fuels into the gas system. This approach will facilitate customer understanding of the benefits and cost implications of the renewable gas and their options to incorporate it into their fuel mix.

3. Pilot and Deploy Innovative Electrification and Decarbonized Technologies

The Consultant Report (Part 1) recommends the LDCs pilot and deploy certain technologies and strategies to evaluate from a research and development perspective what role they play in the transition. There are four technologies the Consultants recommend pursuing.

Networked Geothermal

The Consultants recommend LDCs develop pilot opportunities for networked geothermal systems as potentially strategic replacements of planned capital spending. The pathways analysis shows networked geothermal systems can provide benefits to customers, the energy system, and the LDC business model. However, many questions remain regarding technical implementation, financing, and role in avoiding gas infrastructure investments.

The design elements for pilot opportunities generally would be consistent with those in the Eversource and National Grid Networked Geothermal Pilot Programs. Eversource has a three-year Network Geothermal Pilot Program in Eastern Massachusetts that was approved by the Department in October 2020.[27] National Grid has a five-year Geothermal District Energy Demonstration Program that was approved by the Department in 2021.[28]

Targeted Electrification

The Consultants recommend LDCs develop pilot opportunities for gas system cost savings through strategic and targeted electrification. The pathways analysis shows targeted electrification could avoid certain gas infrastructure investments. However, substantial uncertainties remain regarding the technical implementation, customer implications and protections, and role in avoiding gas infrastructure investments.

Hybrid Heating Systems

The Consultants recommend LDCs promote adoption of building electrification, including hybrid strategies and all-electric new construction, where possible, and to investigate the most optimal operation of hybrid systems in support of the gas and electric systems. The pathways analysis illustrates that hybrid electrification strategies that leverage the gas system presents the lowest level of challenge.

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[26] Application 19-02-015, 'Decision Adopting Voluntary Pilot Renewable Natural Gas Tariff Program' California Public Utilities Commission (CPUC) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M349/K624/349624040.PDF. Also see https://www.socalgas.com/sustainability/renewable-gas/biogas-and-renewable-natural-gas

[27] D.P.U. 19-20, 'ORDER' (October 2020)

[28] D.P.U. 21-24 'ORDER' (December 2021)

The design elements for hybrid heating systems would include introduction of new technologies, such as installation of integrated controls with hybrid heating systems. During the 2019-2021 Energy Efficiency Plan term, the Mass Save PAs created the first integrated controls specifications and requirements to ensure that heat pumps installed to augment existing systems operate efficiently. In the 2022-2024 Energy Efficiency Plan,[29] the PAs proposed additional studies that would help in further understanding and optimizing the benefits of hybrid heating systems with integrated controls.[30]

In addition, there is an evaluation of hybrid heating systems sponsored by London Hydro and Enbridge Gas in Ontario, Canada. The 2-year pilot includes smart controls to create hybrid heating solutions. The smart controls can automatically switch between electricity and natural gas depending on electricity price signals and weather forecasts. Customers receive a $3,200 rebate once the hybrid heating system is installed.[31]

There are several industry studies describing the benefits of hybrid heating systems relative to all electric heating systems in cold climates, including in Colorado,[32] Ontario, Canada,[33] and United Kingdom[34]. The benefits include (1) potential for lower annual customer bills, (2) avoidance of electric infrastructure costs to meet heating demands, and (3) lower GHG emissions through lower reliance on dispatchable winter peak generation resources.[35] [36]

Hydrogen and Other Lower Emission Gases

The Consultants recommend the LDCs pursue pilots opportunities to investigate to what extent hydrogen can be added to the network without the need for customer equipment or pipeline upgrades. In addition, the Consultants recommend the LDCs engage in R&D opportunities related to the commercialization of synthetic gases. Finally, the Consultants recommend investigating Certified Natural Gas (Certified Gas), which reduces upstream emissions from the production of

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[29] Three-Year Plan 2022-2024, Docket Nos. D.P.U. 21-120 through D.P.U. 21-129, filed November 2021.

[30] Notably, the recently completed 'DMSHP Integrated Controls Market Effects Study' and proposed 'Heat Pump Crossover Temp Optimization', and 'Heat Pump Metering Impact' studies. Three-Year Energy Efficiency Plan 2022-2024, Appendix H, at 54-57, 68-69.

[31] See more details at: 'Ontario pilot program tests future of advanced hybrid heating' Enbridge, Inc. (September 2021) https://www.enbridge.com/stories/2021/september/enbridge-gas-london-hydro-pilot-project-tests-future-of-advanced-hybrid-heating.

[32] 'Assessment of Natural Gas and Electric Decarbonization in State of Colorado Residential Sector' Gas Technology Institute for Black Hills Energy (September 2020) https://www.gti.energy/wp-content/uploads/2021/03/27888-Final-Report-Black-Hills-Energy-CO-GHG-Analysis-w-Appx-A-09-2020_Rev1-03-2021_GTI.pdf.

[33] 'Future of Home Heating' Study by Advanced Energy Center in collaboration with Enbridge Gas Distribution Inc., (April 2018) https://taf.ca/publications/future-home-heating-report/.

[34] 'Benefits of Hybrid Heat Systems in a Low Carbon Energy System' Guidehouse Netherlands B.V. and Wales & West Utilities Ltd (July 2020) https://guidehouse.com/-/media/www/site/downloads/energy/2020/gh_-benefits-of-hybrid-heating-systems.pdf.

[35] The 'Future of Home Heating' report notes (p. 3): *"Ultimately, when balancing costs to ratepayers, demands on the grid, and the need for deep GHG reductions, beneficial electrification … of Ontario's space heating demands will more likely occur through adoption of hybrid heating, ventilation, and air conditioning (HVAC) systems rather than through full electrification of HVAC equipment."*

[36] The 'Assessment of Natural Gas and Electric Decarbonization in State of Colorado Residential Sector' report notes (p. iii): *"Using hybrid space heating systems whereby electric heat pumps operate at milder temperatures and natural gas heating systems operate at cold temperatures avoids a host of issues with cold climate electric heat pump operation (e.g., higher annual consumer electric bills, electric grid scale-up for peak winter days/months, higher GHG emission rates for dispatchable seasonal winter generation resources, high annual electric heat pump runtime hours)."*

natural gas.[37] Importantly, upstream natural gas emissions are not included in the Massachusetts GHG inventory, but Certified Gas measures can nonetheless reduce the overall environmental impact of natural gas use, even as its use declines.

Regulatory Design

The Consultants recommend the following regulatory designs to enable LDCs to develop pilot and R&D programs.

1. **Develop guidance for review and approval of pilot and R&D programs**

Establish a process for the Department to review and approve pilot opportunities and funding for decarbonized technologies. The current process includes project-by-project evaluation. For example, the Eversource geothermal pilot program was approved as part of general rate case proceeding (D.P.U. 19-120).

An updated process would streamline the current project-by-project approach to facilitate timely evaluation and deployment of technologies. The updated process would include guidance related to qualified projects, such as:

- Filing requirements
- Qualification criteria (e.g., types of technologies)
- Project goals (e.g., reduce gas emissions, optimize use of existing gas and electric systems)
- Pricing and rate design modifications
- Project schedules, milestones, and timeframes for completion
- Potential partnerships with communities and third-party service providers
- Stakeholder engagement with a particular focus on EJ communities
- Tracking and evaluation reports, including future applications
- Customer feedback on education, marketing, and incentives

The guidance should be established in the near-term, encouraging the LDCs to bring forward innovative technological solutions to achieve the Commonwealth's climate goals. Early development of these projects and LDC's experience with these technologies will inform future regulatory changes and rate designs, as well as provide LDCs with valuable learnings on how best to utilize these technologies in system development, planning, and operations.

The New York Public Service Commission (NYPSC) adopted, for example, a resolution that included guidance and principles on demonstration projects to support the New York's Reforming the Energy Vision (REV) policy initiative. NYPSC encouraged utilities and third parties to work with potential stakeholders in the affected communities and develop potential demonstration projects to inform the REV policy initiative. NYPSC allowed the utilities to defer the revenue requirement impacts of the incremental costs of demonstration projects until their next rate plans. The resolution included a better streamlined process that relies on NYPSC Staff's review of utility

[37] While a formal industry-wide definition has not yet been established, S&P Global Market Intelligence defines Certified Natural Gas as "[g]as that has been verified by an independent third party to have been produced in a manner consistent with certain environmental, social and governance standards." (https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/101421-certified-natural-gas-midstream-sector-begins-embracing-concept-standards.)

demonstration projects filings, including review of compliance with NYPSC guidance, cost-benefit analyses, and cost recovery mechanism.[38]

2. **Design cost recovery mechanisms**

Developing pilot opportunities would require funding of costs through a cost recovery mechanism. Potential options include:

> LDAC – current mechanism used to recover energy efficiency, environmental response, and gas system enhancement costs. The LDAC could be expanded to include costs related to pilot opportunities and initiatives.
>
> New mechanism – specifically designed to recover the cost of the pilot opportunities, such as the approach used in New York to recover demonstration project costs.

3. **Track and report on performance metrics**

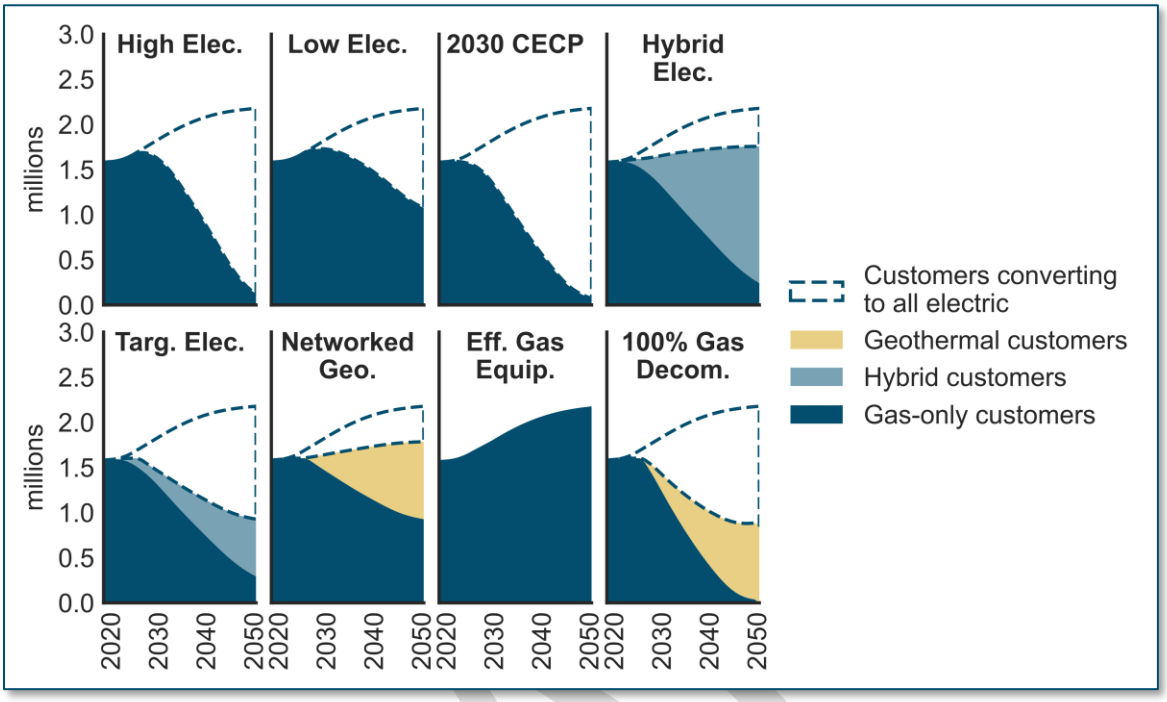
Critical to the pilot programs are a set of clearly defined objectives and results. The regulatory design should establish a process to track and report on performance metrics, including achievement of objectives, costs, installation and service provider participation, customer education, interest and adoption experience, and the role of the project in achieving the decarbonization goals. In addition, the process should include tracking and reporting of projects that have transitioned towards implementation at scale.

4. Manage Embedded Infrastructure Costs

The pathways analysis shows throughput volumes delivered by the gas system decline over time, as shown in Figure 5 (below).

[38] NYPSC 'Order Adopting Regulatory Policy Framework and Implementation Plan', February 26, 2015

Figure 5. Change in Gas Utilization by Pathway (derived from Consultant Report, Part I)



The reduction in system utilization creates two issues.

First, the declines result in higher cost burdens for customers who remain on the gas system as the costs to operate and maintain the natural gas distribution system (i.e., the embedded gas infrastructure costs) are recovered from fewer customers and throughput volumes. Pathways with a faster transition (i.e., steeper declines in customers and system utilization) create higher customer cost burdens raising customer affordability and intergenerational equity concerns. These pathways may require more immediate regulatory support and actions.

Second, the declines create a mismatch between how LDC embedded gas infrastructure investments are recovered, which is based on useful life, and utilization of the gas system, which declines over time based on the pathways analysis. For example, distribution mains are typically recovered over 50-to-70 years on a uniform, straight-line basis. The mismatch is illustrated for the 100% Decommissioning pathway in Figure 6 (below).

Figure 6 (illustrative): Annual Revenue Requirements and number of customers under 100% Gas Decommissioning Pathway

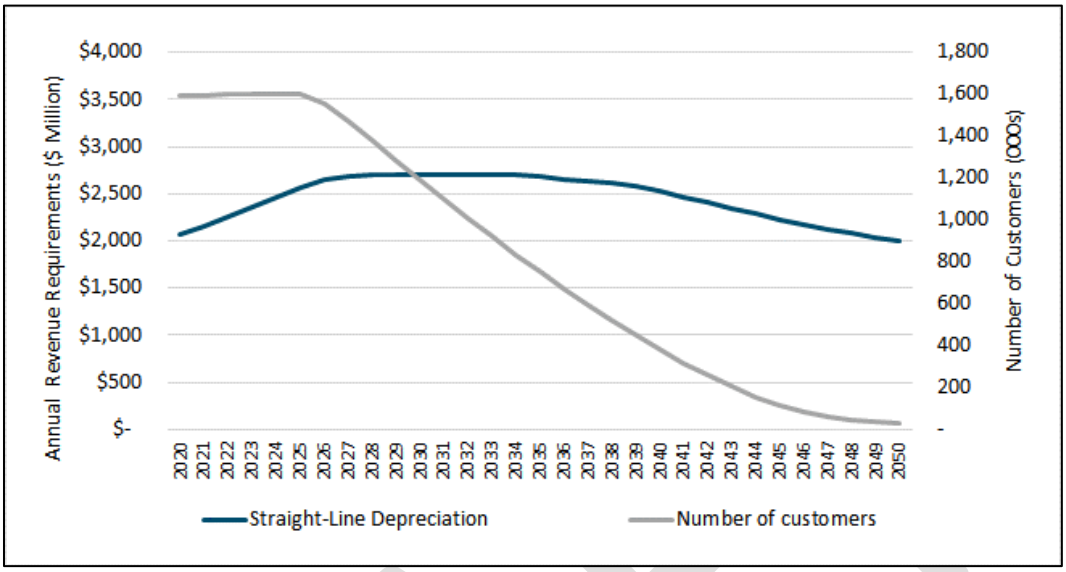


Figure 6 shows the annual revenue requirements associated with the recovery of LDC embedded investments remains relatively consistent (approximately $2.0-$3.0 billion) through 2050. This is primarily driven by the cost of the embedded gas infrastructure. By comparison, the number of customers decline over time in the 100% Decommissioning pathway from 1.6 million customers in 2020 to none by 2050. As a result, there are no customers or throughput volumes in 2050 from which to recover the embedded gas infrastructure costs.

There are two potential strategies to address the mismatch: (1) identify opportunities to limit gas infrastructure investments, subject to maintaining safety and reliability standards, through strategic and targeted electrification and decarbonization solutions; and (2) align cost recovery of the embedded gas infrastructure with utilization through accelerated depreciation.

These strategies, however, are subject to the LDCs continuing obligations to operate the gas system in a safe, reliable, and cost-effective manner.

Regulatory Designs

The Consultants recommend four regulatory designs to support recovery of embedded infrastructure costs.

(1) Establish process to review and pre-approve LDC plans for capital investments

(2) Develop framework for examination of opportunities to avoid gas infrastructure projects

(3) Revise standards for investments to serve new customers

(4) Align gas infrastructure cost recovery and utilization

1. Establish process to review and pre-approve LDC plans for capital investments

The regulatory designs include establishing a process to review and approve LDC plans for capital investments, including thresholds for review and approval. These would include non-GSEP investments, such as those related to safety, reliability, and system reinforcements. GSEP-related capital investments would not be included as there is already a process mandated by legislation that requires the Department to review and approve LDC plans for GSEP capital investments.[39]

The regulatory design would include holistic and transparent long-term capital planning that considers alignment with the decarbonization goals and continuous evaluation of possible solutions and strategies to achieve these goals. The process would include evaluation of current policies, requirements, and obligations for qualified capital investments to support the decarbonization pathways while maintaining safety, reliability, and cost-effective service. The process may include review of LDC capital plans every three years similar to the Department's review of LDC energy efficiency plans.

The process would also evaluate changes in forecasted demands driven by the decarbonization initiatives. Potential changes in future demands would inform decisions on capital projects that are necessary for safe and reliable service, and projects that can be avoided, for example, through non-pipeline alternatives.

2. **Develop a framework to examine opportunities to minimize or avoid gas infrastructure projects, while maintaining safety and reliability of service to customers and compliance with pipeline safety requirements**

The regulatory designs include developing a framework for examination of opportunities to avoid gas infrastructure projects, while maintaining safety and reliability of service to customers. The framework may be part of the review process for LDC capital plans described above. The framework would include a standard for review and approval of capital projects, such as (a) geographically targeted electrification, (b) non-pipeline alternatives (NPAs), and (c) networked geothermal systems.

a. Geographically Targeted Electrification

One approach to address recovery of embedded infrastructure costs is to encourage geographically targeted electrification as an alternative to replacing non-cathodically protected steel, cast-iron, and wrought-iron and aged pipe and/ or installing new pipe to upgrade pipeline capacity. Targeted electrification consists of replacing all gas heating systems with electric heating systems in certain targeted geographical areas. This option may require legislative changes to address the LDC's obligation to serve customers who wish to retain their gas heating system and outline consumer protections (see detailed discussion in Section 4).

Presently, Pacific Gas & Electric (PG&E) has a program to avoid infrastructure replacements by converting customers to electric equipment. The program has faced several barriers, including: (1) all customers in a specific area must agree to terminate gas service and switch to electric service at that same time; (2) the conversions need to make sense financially, i.e., the cost of electrification

[39] *"On or before October 31st of each year, the gas distribution companies are permitted to submit annual Gas System Enhancement Programs (GSEPs) for replacement of aged (non-cathodically protected steel, cast-iron, and wrought-iron infrastructure during the following calendar year."* 'GSEPs Pursuant to 2014 Gas Leaks Act' Commonwealth of Massachusetts https://www.mass.gov/lists/gseps-pursuant-to-2014-gas-leaks-act.

needs to be lower than the cost of gas capital projects; and (3) the utilities need to have access to funds that can be used to incentivize the customers to electrify.[40] To date, PG&E has identified two dozen miles of successful gas decommissioning opportunities out of a total system with over 50,000 miles of gas transmission and distribution pipelines, illustrating the nascent stages of this initiative.[41]

b. Non-Pipeline Alternatives (NPAs)

A second approach is to encourage Non-Pipeline Alternatives (NPAs) as an alternative to replacing non-cathodically protected steel, cast-iron, and wrought-iron and aged pipe and/ or installing new pipe to upgrade pipeline capacity.[42] NPAs include installation of energy efficiency measures, decarbonized heating technologies, and demand response solutions.

Presently, Con Edison has a Non-Pipeline Solutions (NPS) portfolio that was approved by the New York Public Service Commission (NYPSC) in 2019.[43] The NPS addressed two issues: (1) the significant growth in natural gas demand due to various factors, including local governments' phase-out of high-emitting fuel oil, economic growth, and the relatively low natural gas prices, and (2) New York's energy policy that calls for reduced reliance on fossil fuels. Con Edison's NPS portfolio included demand-side solutions, such as energy efficiency and heating electrification, and supply-side solutions, such as RNG, CNG, and LNG projects to provide peak day supply capability.

In addition, National Grid, in New York, has made commitments to evaluate, where possible, non-pipeline alternatives (such as geothermal heat pumps) before proceeding with the construction of new or replacement gas transmission and distribution infrastructure.[44]

c. Networked Geothermal Systems

A third approach is to install networked geothermal systems. As discussed in Chapter 4 of this Report, networked geothermal systems allow LDCs to leverage their current business models and workforce to operate the systems. As discussed earlier, Eversource has an ongoing three-year Network Geothermal Pilot Program in Eastern Massachusetts that was approved by the Department in October 2020;[45] and National Grid has a five-year Geothermal Energy Demonstration Pilot Project that was approved by the Department in 2021.[46]

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[40] 'PG&E's Alternative Energy Program: PG&E Strategy to Retire Gas Infrastructure via Electrification' (September 15, 2021 Presentation)

[41] See, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/presentation-for-r2001007-track-2-workshop-1_2022-01-07.pdf

[42] Also called Non-Infrastructure Solutions or Non-Pipeline Solutions. These are analogous to the Non-Wires Alternatives in the electric sector where lower cost EE and DSM measures are installed to potentially defer or avoid transmission and distribution system upgrades.

[43] Case 17-G-0606, 'Order Approving with Modification the Non-Pipeline Solutions Portfolio' (February 2019) New York Public Service Commission (NYPSC)

[44] Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements (NYPSC Cases 20-E-0380 and 20-E-0381), and Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements (NYPSC Cases 19-G-0309, and 19-G-0310)

[45] D.P.U. 19-20, 'ORDER' (October 2020)

[46] D.P.U. 21-24 'ORDER' (December 2021)

3. Revise standards for review and approval of investments to serve new customers

There are two potential approaches to revising the standards for review and approval of investments to serve new customers. The approaches are: (a) develop a framework to coordinate gas and electric utility system planning and investments, and (b) review changes to line extension policies and practices.

a. Framework to coordinate gas and electric utility system planning and investments

This approach requires the Department to consider how to improve coordination between gas and electric utilities, recognizing the complexities of coordinating processes, analytical tools, and people that historically have been separate and distinct. Such coordination could result in addressing recovery of embedded infrastructure costs, especially through strategic deployment of all-electric systems and hybrid heating systems that continue to utilize the gas system. The process would include gas and electric utilities incorporating coordinated assumptions in planning processes on anticipated electrification and changes in gas demands. The integrated planning process would also include alignment between the gas and electric utilities on decarbonization goals and initiatives.

A coordinated gas and electric planning approach is particularly important to support reliability and resilience of the electric grid. Decarbonization pathways that rely on significant electrification, particularly all-electric heating systems, lead to substantial increases in winter peak demand for electricity and associated investments in electric generation, transmission, and distribution facilities. Particularly, the electric system would require significant peaking resources to ramp-up generation during winter peak demands.

In addition, these decarbonization pathways lead to significant customer migration from the gas system, leaving behind uncollected the costs that were originally incurred to serve the departing customers. Under the current ratemaking practices there is misalignment between those responsible for paying the costs (i.e., remaining customers) and those responsible for the incurred costs (remaining customers and those that have transitioned to electricity).

These concerns can be resolved through hybrid heating systems that optimize customer utilization of both gas and electric systems. Hybrid heating systems reduce or mitigate the level of investment in the electric system since winter peak demands are met through the gas system and improve utilization of the gas system as compared to all-electric heating systems. As discussed earlier in the report, the gas and electric utilities may establish a benefit-sharing mechanism, similar to the "dual energy" agreement between HQD and Energir.

A coordinated gas and electric planning approach is also important for strategic deployment of all-electric heating systems i.e., targeted electrification. A coordinated gas and electric planning process could identify capacity constraints (or capacity availability) across both systems and optimize the set of capital investments that best meet the demand requirements.[47] In addition,

[47] This has been recognized in industry publications. For example, RAP notes: *"As the trends affecting the gas industry are not limited to gas utility proceedings, regulators may want to consider coordinating or at least cross-referencing other planning processes that may affect gas utility decision-making. Consideration of electric utility plans, for example, may be important to determine whether gas and electric utilities are making similar assumptions about electrification and anticipating that as electrification proceeds, demand for gas will decrease and demand for electricity will increase."* Anderson, Megan., LeBel, Mark., & Dupuy, Max, Under

the integrated planning process would identify opportunities for avoiding gas infrastructure replacement projects through strategic electrification in areas where a large percentage of customers have already migrated towards electrification.

One challenge of a coordinated gas and electric planning process is that most customers do not share the same gas and electric utilities (see discussion in Consultant Report (Part I).

Table 3. Electric and gas service providers in Massachusetts (derived from Consultant Report, Part I)

Gas Provider	Electricity Provider			
2020 Gas Customers	National Grid	Eversource	Unitil	Municipal
National Grid	378,500 39%	469,800 49%	800 0%	110,400 12%
Eversource	272,500 42%	311,900 48%	NA	61,400 10%
Unitil	2,100 13%	NA	14,100 87%	NA
Liberty	51,000 85%	4,400 7%	NA	4,400 7%
Berkshire	12,300 30%	28,400 70%	NA	NA

Percentages may not add to 100% due to rounding

The Figure shows, for example, that 60% of National Grid gas customers have an electric utility other than National Grid and over 50% of the Eversource gas customers have an electric utility other than Eversource. Consequently, such coordinated gas and electric planning and investment process in most cases requires coordination across different companies.

b. Changes to line extension policies and practices

This approach requires the Department to revise LDC line extension policies and practices. Presently, the standard for review and approval of LDC investments to serve new customers is based on a condition that existing customers do not subsidize the cost to serve new customers. To meet this condition, incremental revenues associated with investments to serve new customers must be at least equal to the incremental costs.[48] To the extent that such revenues are insufficient, the new customer would be required to pay a contribution-in-aid-of-construction (CIAC) to recover the expected shortfall.

The current payback period to evaluate investments to serve new customers is generally 10-to-20-years. However, if new customers leave the gas system before completion of the payback period, then incremental revenues could be less than incremental costs.

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pressure: Gas utility regulation for a time of transition, Regulatory Assistance Project (May 2021) https://www.raponline.org/knowledge-center/under-pressure-gas-utility-regulation-for-a-time-of-transition/

[48] See for example, Boston Gas Terms and Conditions that state: *"The Company reserves the right to reject any application for service if…the estimated income from the service applied for is insufficient to yield a reasonable return to the Company, unless such application is accompanied by a cash payment…or guaranteeing a stipulated revenue for a definite period of time, or both."* 'M.D.P.U. No. 4.3. Boston Gas Company d/b/a National Grid. Distribution Terms and Conditions Clause' http://www2.nationalgridus.com/docs/partners/marketers/Boston_Tariffs.pdf.

There are four potential changes that would address the misalignment between incremental revenues and costs associated with new customer additions:

- Shorten the payback period
- Reduce customer revenues supporting the investment
- Increase the target rate of return on the investments
- Require customers to guarantee the revenues supporting the incremental costs, particularly in the case of large or high volume commercial and industrial customers requiring large investments

4. Align gas infrastructure cost recovery and utilization

The regulatory designs include evaluating changes to the current depreciation method from one that reflects the useful life of the investments on a straight-line basis to one that reflects utilization life of the investments.

For example, The Units of Production (UOP) depreciation method aligns cost recovery of the gas system investments to the expected utilization of the gas system. The UOP method is recognized by NARUC as, *"Unit of production methods estimate depreciation costs on the basis of units of production (e.g., energy transmitted) rather than as a function of time."*[49]

An illustrative example of cost recovery on a $ per MMbtu basis under straight-line depreciation and UOP method is presented in Figure 7 below.[50]

[49] 'Depreciation Expense: A Primer for Utility Regulators' National Association of Regulatory Utility Commissioners (NARUC) (May 2021)

[50] The illustrative scenario in the figure assumes a $10.0 million investment with asset life of 30 years. The investment is recovered annually through volumetric charges applied on a total throughput of 1.0 million MMBtu that decreases annually by 0.25 percent.

Figure 7 (illustrative): Annual Depreciation Expense $ per MMBtu Under Straight-Line vs. UOP Depreciation

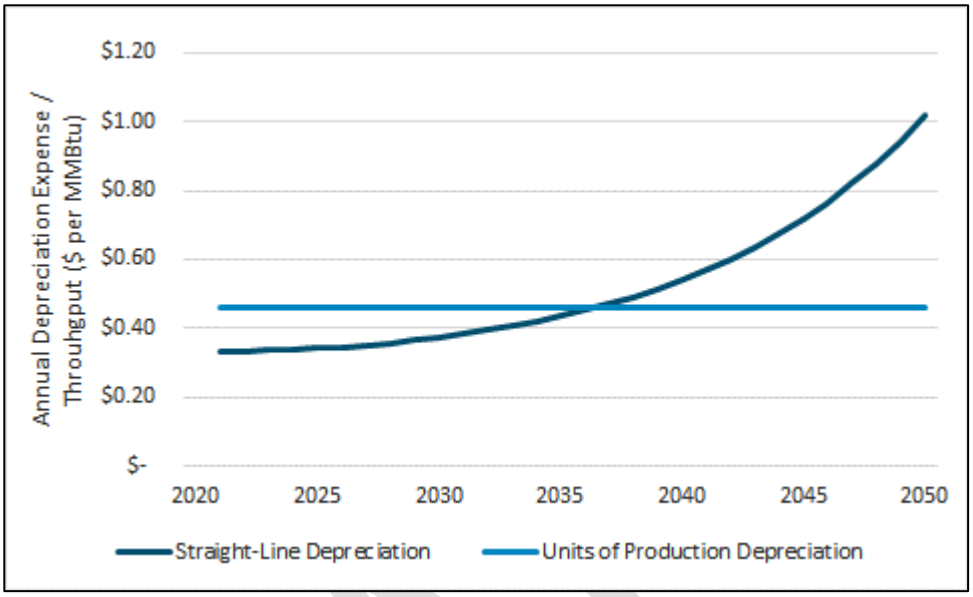

Figure 7 shows that annual depreciation expense expressed on a $ per MMBtu basis increases under the straight-line depreciation method, reflecting a decline in throughput. By comparison, the annual depreciation expense remains constant under the UOP method. an alternative method i.e., the Units of Production (UOP) method.

While the depreciation expense remains constant on a $ per MMBtu basis, the UOP method may result in lower financing costs in the long-term as net assets are lower due to the accelerated depreciation in the near-term. An illustrative example is shown in Figure 8 below.[51]

[51] The illustrative scenario in the figure considers same assumptions as illustrative scenario presented in Figure 7. In addition, the scenario assumes that the utilities finance the assets at 12.50 percent pre-tax weighted cost of capital.

Figure 8 (illustrative): Annual Depreciation + Financing Costs $ per MMBtu Under Straight-Line vs. UOP Depreciation

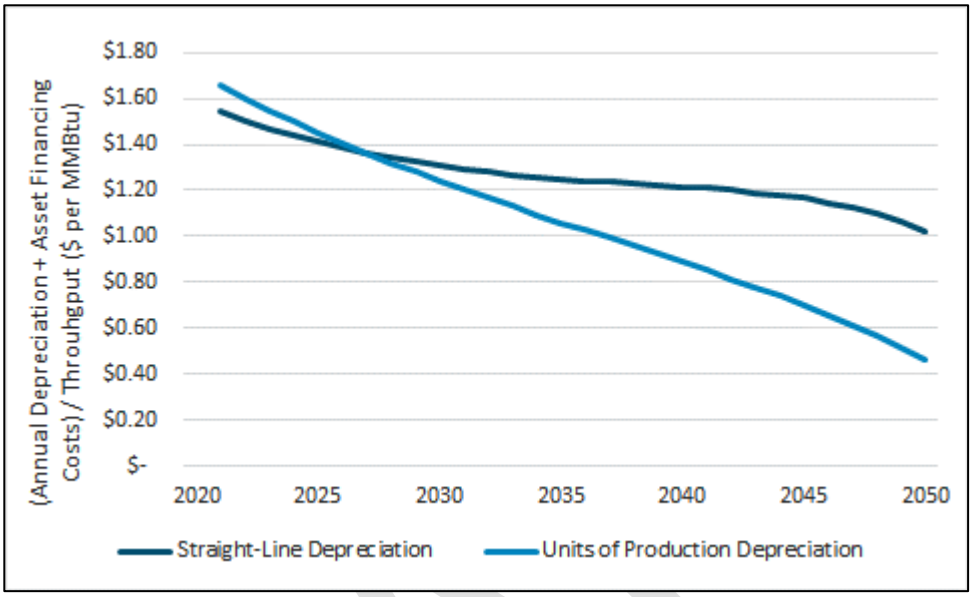

Figure 8 shows that costs are higher on a per MMBtu basis under the UOP method in the initial years, and lower in the later years.

Another alternative depreciation method, similar to UOP, is implementing shorter asset service lives. National Grid, for example, in its recent general rate proceeding (D.P.U. 20-120), proposed shorter service lives in calculating depreciation for certain assets, effectively increasing the cost recovery of depreciation expenses in the near-term. National Grid's proposed shorter service lives reflected the potential impact of decarbonization, specifically in terms of future declines in consumption and customer migration. The Department did not approve National Grid's proposal citing the current uncertainty surrounding the future of LDCs' operations, planning, and cost implications as well as the on-going investigation in this proceeding (D.P.U. 20-80) on these issues.[52]

An important consideration in changing depreciation method would be the expected future system utilization. For example, the UOP method requires establishing a relatively accurate forecast of expected utilization of the gas system. Similarly, establishing shortened asset service life requires an accurate assessment of the usefulness of assets.

The pathways analysis shows varying levels of gas system utilization under decarbonization pathways. Pathways with lower future utilization of gas system, such as High Electrification and 100% Gas Decommissioning, require higher increases in depreciation rates in the near term to align with expected utilization of the system. Pathways with continued future utilization of gas system, such as Efficiency Gas, Low Electrification and Hybrid Electrification, require lower increases in

[52] Specifically, the Department stated: "While the Department recognizes the use of informed judgment in depreciation analysis, the current uncertainty surrounding the future of LDCs' operations and planning and associated cost implications, in addition to recognizing the Department's on-going investigation into issues related to these matters in D.P.U. 20-80, lead us to conclude that it is not appropriate to approve the Company's proposed changes to depreciation at this time." (D.P.U. 20-120, 'Order' September 30, 2021, at p. 244)

depreciation to align with expected utilization of the system. The varying system utilization under the decarbonization pathways has been discussed through Consultant Report (Part I).

Figure 9 below illustrates the LDC revenue requirements under 100% Gas Decommissioning pathway with the UOP method and straight-line depreciation. The figure also shows the impact on delivery rates with the two methods.

Figure 9 (illustrative): Annual Revenue Requirements and number of customers under 100% Gas Decommissioning Pathway, with UOP method

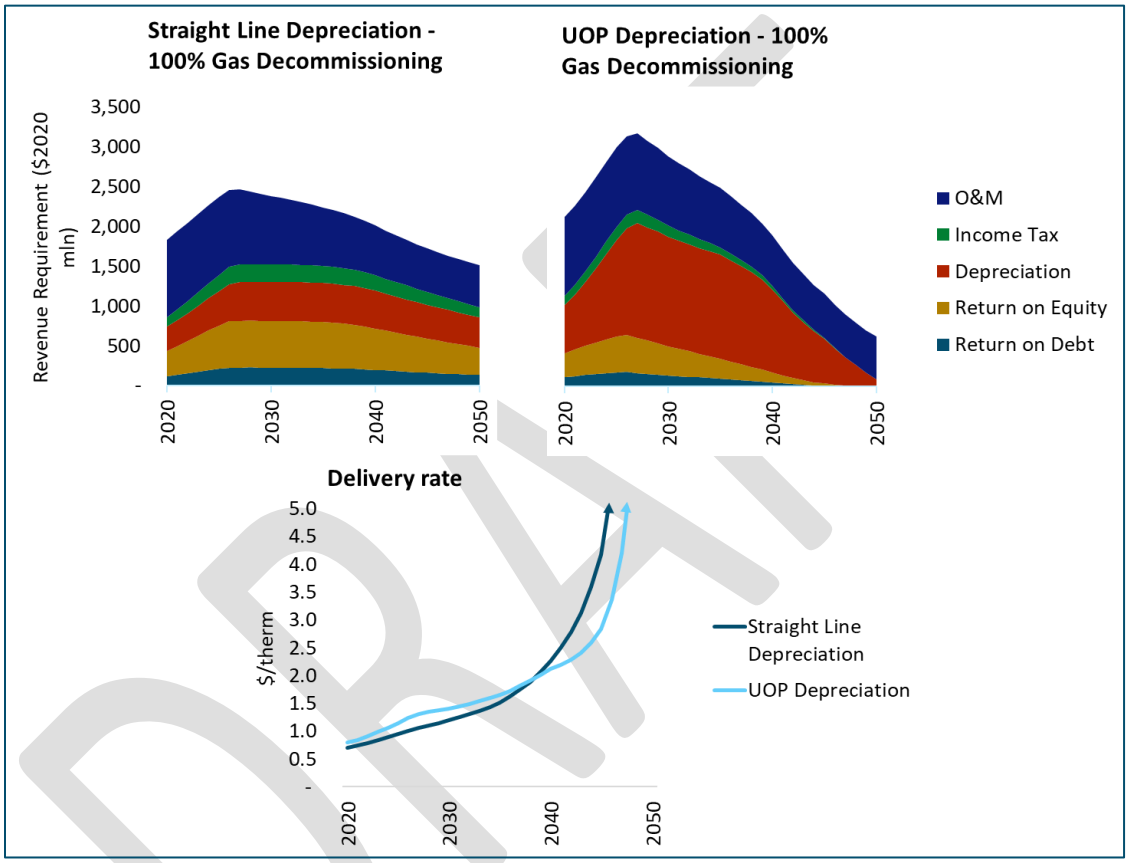

Figure 9 shows that the UOP method results in increased cost recovery in the near-term (2020-2030), which is expected to be the period prior to customer departures from the gas system. As customers start departing the system under the 100% Decommissioning pathway, the cost recovery also decreases, addressing customer affordability and intergenerational equity concerns.

Accelerated depreciation helps address concerns related to unrecovered rate base as customers leave the system. In doing so, it helps mitigate affordability and equity concerns. For example, accelerated depreciation results in a reduction in potential LDC unrecovered rate base, as shown in Figure 10 (below).

Figure 10 (illustrative): 2050 Unrecovered Rate Base Under Straight Line Depreciation vs. Units of Production Depreciation[53]

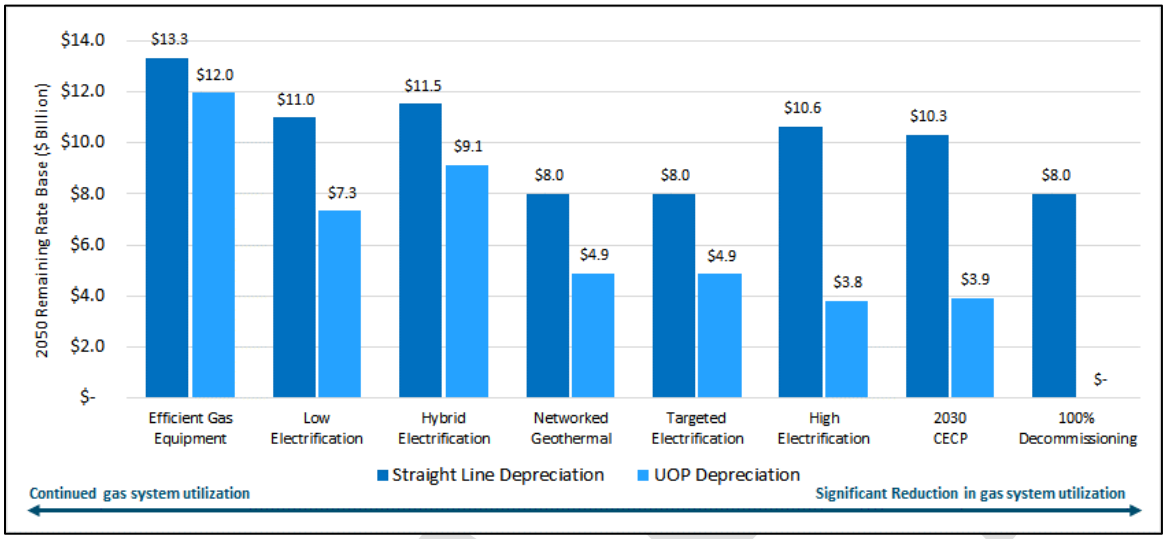

Figure 10 shows that lower unrecovered rate base in 2050 under the UOP depreciation method, particularly in those pathways with substantial declines in gas system utilization.

A final consideration in evaluating changes in deprecation method is the impact of near-term rate increase on the overall decarbonization transition. In the near-term, the UOP depreciation method raises rates, which improves the economics for customers considering electrification. The increased electrification may create additional burdens for those customers who remain on the gas system. One option to address the rate impact concerns is to phase-in over time the higher depreciation rates.

5. Evaluate and Enable Customer Affordability

Decarbonization pathways result in customer affordability and equity concerns for LDC customers who remain on the gas system. Unit costs for LDC customers who remain on the gas system increase substantially under the decarbonization pathways albeit at different trajectories, as shown in Figure ***11*** (below). Customer affordability and equity impacts have also been discussed throughout the Consultant Report (Part I).

[53] Excluding rate base related to networked geothermal projects

Figure 11. (Derived from Consultant Report, Part I). Residential Gas Unit Costs by Pathway

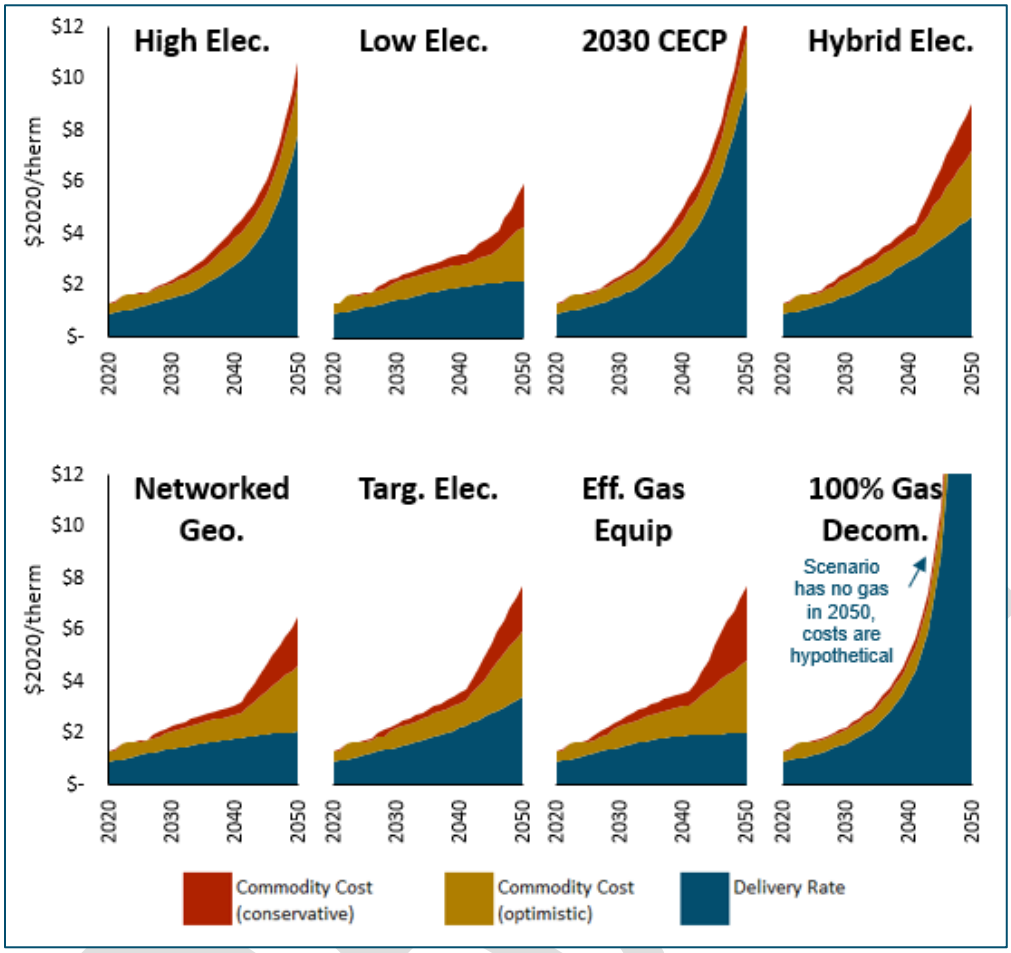

Figure *11* shows that residential unit cost increases are attributable to two sets of costs. Under certain pathways, the higher rates are largely attributable to higher delivery costs. Under High Electrification, for example, the higher rates are largely attributable to customers departing from the gas system, leaving behind uncollected embedded gas infrastructure costs. Under current ratemaking practices, those costs are recovered from customers remaining on the system. In other pathways, such as Low Electrification, the higher rates are largely attributable to the higher cost of renewable gas in the gas system.

There are three considerations that drive the need for expanding the scope of cost recovery:

- **Magnitude of cost impacts.** In certain scenarios, the magnitude of customer cost impacts is extraordinary and well beyond the scale and scope of traditional LDC cost recovery mechanisms (see Figure 11 above).
- **Alignment of transition cost recovery with beneficiaries.** The benefits of the decarbonization pathways extend beyond gas customers, who make up only 50% of the state's home heating market. The higher delivery and fuel costs represent implications of achieving the decarbonization pathways; thus, expanding the scope of cost recovery to

include those that benefit from the pathways improves alignment between those that benefit from the pathways and those that are responsible for its transition costs.

- **Mitigation of rate and equity implications.** Importantly, the expanded scope of cost recovery helps mitigate the cost and equity implications of the pathways on LDC customers.

Regulatory Designs

The regulatory designs to address customer affordability concerns include:

(1) Develop framework to identify and quantify transition costs

(2) Evaluate impact of transition costs on customers

(3) Evaluate alternative approaches to finance and/or recover transition costs

1) Develop framework to identify and quantify transition costs

The regulatory designs include developing a framework to identify and quantify transition costs, which include: (1) uncollected costs from customers who have departed the gas system, (2) costs associated with restructuring or realignment of gas supply portfolios, including cost of restructuring supply, storage and pipeline agreements, and (3) other costs, such as workforce transition costs and costs associated with design and implementation of the regulatory reforms, including geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation.

2) Evaluate impact of transition costs on customers

The regulatory designs include evaluating impact of transition costs on customers. While certain options discussed earlier, such as hybrid electrification, help reduce the amount of transition costs, the pathways continue to result in substantial transition costs that require a cost recovery mechanism consistent with the scope and scale of the transition costs.

Under some pathways, such as 100% Gas Decommissioning, the transition costs grow quickly and have a substantial impact on customer rates much earlier in the decarbonization pathway. Under other pathways, such as hybrid electrification, the transition costs grow more slowly and have a substantial impact on rates later in the decarbonization pathway. Under all pathways, however, there is a substantial impact on rates by the end of the pathway.

3) Evaluate alternative approaches to recover transition costs

There are two approaches that can be evaluated to mitigate cost recovery to remaining LDC customers: (1) cost recovery from customers leaving the gas system (migration charge), and more broadly (2) Massachusetts-wide cost recovery (transition charge).

<u>Evaluate Cost recovery from customers leaving the gas system (migration charge or other cost recovery mechanism)</u>

Under this regulatory design, customers leaving the gas system would be charged for costs that were incurred to serve them but not collected. For example, the customers leaving the gas system would be charged a 'migration charge'. This option would likely require legislative approval since the charge would be based on LDC costs charged to non-LDC customers.

This option better aligns cost recovery with cost incurrence. This approach also minimizes the cost shift to customer remaining on the system as well as minimizes the potential for non-recovery of embedded costs. A variation of this option was considered in Netherlands such that households pay a flat fee to disconnect from the gas system.[54]

Another variation of this option has been implemented in California for electric customers who choose to obtain service from non-utility providers, such as through direct access or community choice aggregation (CCA). According to the California Public Utilities Commission (CPUC), the purpose of the Power Charge Indifference Adjustment (PCIA) is *"to make sure that customers leaving the utility do not burden remaining utility customers with costs which were incurred to serve them… Without the PCIA, the remaining utility customers would need to assume costs that the [investor-owned utilities] incurred in anticipation of serving the customers that now receive electric service from a CCA or Direct Access."*[55]

There are several challenges to implementing a 'migration charge'. First, the charge would likely require legislative approval, making the authorization process complex. Second, the charge would likely reflect the timing of when customers leave the gas system and the amount of costs that are uncollected. The charge calculations could therefore be complicated and contentious. Finally, the charge may lead to customer confusion with other potential reforms, for example, having a migration charge when customers leave the gas system while other customers having a migration "incentive" if they are part of a targeted electrification program.

<u>Evaluate sharing "Transition" costs with non-LDC customers (electricity surcharges or other funding mechanisms)</u>

Under this regulatory design, the "Transition" costs associated with the decarbonization pathways would be shared more broadly with non-LDC customers to address customer affordability and equity concerns discussed throughout this report. The primary benefit of this option is to better align the benefits of decarbonization with the transition costs associated with decarbonization.

The timing of when to implement this option depends in large part on the decarbonization pathway. For those pathways that have a substantial impact on rates earlier in time, this option should be considered earlier in the process. For those pathways that have a substantial impact on rates later in time, this option could be considered later in the process. In all cases, however, this option should be considered to address customer affordability and equity concerns.

One of the primary concerns with this option is that non-LDC customers would be responsible for LDC costs. There are two overarching implications from the Commonwealth's climate goals: (1) the decarbonization pathways show that it is impractical to expect LDC customers to pay for the transition costs; and (2) the option better aligns the cost of the pathway to the beneficiaries of the pathway, namely the Commonwealth's homes and businesses.

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[54] 'Impacts of Socialising the Costs of Gas Grid Disconnection' CE Delft (May 2019) https://cedelft.eu/publications/impacts-of-socialising-the-costs-of-gas-grid-disconnection/.

[55] 'Power Charge Indifference Adjustment' https://www.cpuc.ca.gov/consumer-support/consumer-programs-and-services/electrical-energy-and-energy-efficiency/community-choice-aggregation-and-direct-access-/power-charge-indifference-adjustment

The mechanism of how the transition costs would be recovered should be evaluated. The process could start with establishing a fund, and then identifying funding sources. This approach has been suggested by others. [56]

An illustration of customer rate and equity impact mitigation is presented in Table 4 below. The Table presents customer rate impacts under the High Electrification pathway with four cost recovery approaches:

A) **Current Framework**. Costs recovered from Gas LDC customers

B) **Accelerated Depreciation**. Costs recovered from Gas LDC customers with UOP depreciation

C) **Exit Fees.** recovered from existing and former LDC customers

D) **Electricity Surcharges.** Transition costs recovered from all MA households (i.e., electric customers)

Table 4. Potential customer rate and equity impact mitigation options. Shown for Straight Line Depreciation as well as Units of Production depreciation.

2050 cost impacts vary depending on which customers are included in the revenue base		
High Electrification pathway, optimistic cost reductions, **straight-line depreciation**. 2050 gas revenue requirement of **$2.3B** ($2020)		
Revenue base (cost recovery)	**Number of customers**	**$/customer ($2020)**
Remaining gas customers (Gas rates)	120,000 *= gas customers remaining by 2050*	$19,000/year
Anytime gas customers (Gas rates and exit fees)	1,700,000 *= gas customers remaining by 2050 + customers converting to all-electric*	$1,400/year
Electric customers (Electric surcharges)	3,300,000 *= gas + electric customers*	$700/year
High Electrification pathway, opt. cost reductions, **units of production depreciation**. 2050 gas revenue requirement of **$1.6B** ($2020)		
Revenue base (cost recovery)	**Number of customers**	**$/customer ($2020)**

[56] RAP notes: *"Policymakers may look to other sources of funding to ameliorate rate impacts on future gas customers. There is no silver bullet, as many sources come with significant complications … **General funds and taxes** could provide funding to assist with the gas transition. Direct funding from the state or federal government, as well as various forms of tax assistance, could be significant, although budgets are often constrained…"* Anderson, Megan., LeBel, Mark., & Dupuy, Max, 'Under pressure: Gas utility Regulation for a Time of Transition' (May 2021) (p. 16)

Remaining gas customers (Gas rates)	120,000 *= gas customers remaining by 2050*	$13,000/year
Anytime gas customers (Gas rates and exit fees)	1,700,000 *= gas customers remaining by 2050 + customers converting to all-electric*	$1,000/year
Electric customers (Electric surcharges)	3,300,000 *= gas + electric customers*	$500/year

4) Evaluate securitization as potential method to finance transition costs

The regulatory designs include evaluating securitization as a method to finance transition costs. Securitization is an industry-recognized method of financing extraordinary costs.

National Regulatory Research Institute (NRRI) defines securitization as, *"securitization is a special form of financing that is specifically designed to lower a utility's borrowing costs, which in turn lowers the amount of money customers will have to repay … Essentially, it lets utilities and their customers benefit directly from the bond market."*

The revenue streams related to the securitization are considered highly secure, resulting in high debt ratings and lower interest rates. As a result, customers benefit through lower financing costs than they otherwise would receive without securitization.

Securitization has been used in the utility industry to finance recovery of extraordinary costs,[57] such as wildfire mitigation costs in California, coal plant decommissioning costs in New Mexico, and Storm Uri costs in Texas, while minimizing the impact on customer rates.[58] [59] [60] One of the challenges with securitization is the requirement to have a secure revenue stream. The revenue stream under the decarbonization pathways is subject to significant uncertainty as customers and

[57] The NRRI notes: *"When a utility has an extraordinary cost, for which it is prudent to recover costs from customers (e.g., sunk costs, pollution control equipment, storm recovery costs, remediation of coal ash ponds), it is reasonable to consider securitization as a mechanism to assure cost recovery at a rate below the utility's cost of capital. It is also a unique and valuable tool for regulators and utilities to avoid customer rate shock."*

'Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update' NRRI Insights, January 2019, https://pubs.naruc.org/pub/34058ED0-1866-DAAC-99FB-B8BC5BCC625C.

[58] Case No. 00007064, 'Application of CenterPoint Energy Resources Corp. for Customer Rate Relief and Related Regulatory Asset Determination' The Railroad Commission of Texas (June 2021)

[59] Case No. 19-00195-UT, 'In the Matter of Public Service Company of New Mexico's Consolidated Application for Approvals for the Abandonment, Financing, and Resource Replacement for San Juan Generating Station Pursuant to the Energy Transition Act', New Mexico Public Regulation Commission

[60] Also see: Trabish, Herman K., 'Securitization Fever: Renewables Advocates Seize Wall Street's Innovative Way to End Coal' Utility Dive (May 2019) https://www.utilitydive.com/news/securitization-fever-renewables-advocates-seize-wall-streets-innovative-w/555089/

throughput volumes leave the gas system. A possible way to address this uncertainty would be through charges on gas and electric bills.[61]

6. Develop LDC Transition Plans and Chart Future Progress

Regulatory Design

The transition towards achieving climate goals requires periodic reporting and planning process. The process can be similar to the Department's energy efficiency and GSEP review and approval processes. For example, the process may include LDCs filing evaluation and planning reports every 2-4 years. The reporting and planning process may include:

Evaluation of progress on transition plan, and potential modifications. The reporting and planning process would include a review of LDC progress towards achievement of climate goals. The LDCs may also report on the challenges, such as externalities that are not under control of LDCs and provide necessary regulatory solutions to address these challenges. The reporting and planning process may include LDC filings for modifications in transition plans based on LDC's lessons learned in achieving the climate goals.

Review and pre-approval of LDC capital investments. The reporting and planning process would include the review and pre-approval of certain future LDC capital investments. GSEP-related capital investments would not be included in this process as there is already a process mandated by legislation that requires the Department to review and approve LDC plans for GSEP capital investments. First, the LDCs continue to invest in necessary gas system replacement and upgrades to provide safe and reliable gas service. The transition planning and reporting process would include review and approval of these other strategic opportunities and LDC capital investments. Second, as discussed in this report, the LDCs identify strategic opportunities to avoid new gas infrastructure, such as through targeted electrification, non-pipelines alternatives, and networked geothermal deployment. These initiatives reduce future LDC cost recovery and facilitate achievement of climate goals.

Review of gas and electric coordination opportunities. The reporting and planning process would include review of LDCs initiatives for cross coordination between gas and electric utilities. As discussed earlier, the achievement of climate goals requires coordinated gas and electric system planning and capital investments, such as through strategic deployment of all-electric systems and hybrid heating systems that continue to utilize the gas system. The process would include LDCs' review of overall gas and electric system capacity and planning needs, including infrastructure, customer demands, critical infrastructure needs, and reliability expectations. The process may

[61] This approach has not been implemented anywhere to the best of our knowledge, although it has been suggested. Synapse Energy Economics notes: *"Securitization theoretically offers additional flexibility because the bond could be paid off by sources of capital other than gas rates (e.g. it could in theory be repaid through electric rates or tax revenues, after what would surely be extensive stakeholder and political process) …"*

'Gas Regulation for a Decarbonized New York' Synapse Energy Economics (June 2020) https://www.synapse-energy.com/project/gas-regulation-decarbonized-new-york

include potential cross utility sharing of costs and benefits associated with decarbonization initiatives.[62]

Review and approval of cost recovery. The reporting process would include the review and approval of cost recovery mechanisms to recover costs and return on investments associated with LDC capital investments and pilot projects. As discussed earlier, these may include LDAC expansion, R&D fund, or other sources. These may also include review of other funds to mitigate customer cost impacts, such as funds through legislative action. Lastly, the process may include review of LDCs cost recovery challenges and potential rate design changes.

Evaluation of customer affordability metrics. As discussed through this report, the rate and equity impacts on customers vary by magnitude and ramp-up under each pathways scenario. Periodic monitoring and evaluation of key metrics is needed to ensure that required regulatory changes can be implemented in a timely fashion to mitigate these affordability and equity concerns with a particular focus on low-income and EJ communities.

Reporting and Evaluation: LDCs could present certain data with each plan filing, including:

- **Customer data**
- **Renewable natural gas customers**
- **Emissions calculations**
- **Rates and bill impacts**
- **EJ Community impacts**

Performance incentives. The planning and evaluation process can be used to design performance metrics and incentives to align the LDC's financial incentives with the Commonwealth's goals. Performance incentives can encourage innovation and initiatives and has been recognized by regulatory commissions as a way to best assure furtherance of public policy goals.[63][64]

[62] See for example, earlier discussion on the 'dual energy' agreement between Hydro-Quebec and Energir

[63] NYPSC states: "Aligning financial incentives with policy goals is the best way to assure furtherance of these goals." New York PSC. CASE 14-M-0101. 'Order Adopting a Ratemaking and Utility Revenue Model Policy Framework', May 19, 2016, at p. 39

[64] The Department states: "…the Department has found that performance incentives can serve as a useful regulatory mechanism when used to positively influence distribution company behavior in the advancement of important public policy goals that are not directly aligned with a distribution company's public service obligation." M.D.P.U. No. 20.120. Boston Gas Company d/b/a National Grid. 'Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Plan' at p. 131.

4. Conclusion

Overall, the regulatory designs recommended in this report represent a meaningful step toward supporting the Commonwealth's achievement of its climate goals while mitigating cost and rate impact on customers and maintaining optionality for LDCs and customers. While the regulatory designs are needed to support all pathways, the scale, timing, and nature of transition to net zero emissions varies by pathway, as shown in Table 5 (below).

Table 5. Scale, Timing and Nature of Regulatory Designs[65]

Objectives	Efficient Gas Equipment	Low Electrification	Hybrid Electrification	Networked Geo. & Targeted Elec.	High Elec., 2030 CECP & 100% Gas Decom.
1. Support customer adoption of electrified/ decarbonized heating technologies	●	●	●	●	●
2. Blend renewable gas in gas resource portfolios	●	●	●	●	●
3. Pilot and deploy electrification and decarbonized technologies	●	●	●	●	●
4. Manage embedded infrastructure costs	●	●	●	●	●
5. Evaluate and enable customer affordability	●	●	●	●	●
6. Develop LDC transition plans and chart future progress	●	●	●	●	●

Scale, timing, and nature of transition

○ ● ● ●

Lower, Less Immediate Need **Higher, More Immediate Need**

[65] Assumptions
1. Mix and pace of customer adoption of electrification and decarbonized technologies (Figure 1)
2. Based on blending (%) of decarbonized fuels in the pathways (Figure 2)
3. Number of new technologies and fuels (Figures 1 and 2)
4. Changes in gas utilization and uncollected gas infrastructure costs (Figures 5 and 10)
5. Gas unit costs (Figure 11)
6. Transition planning required in all pathways

The table shows that the scale and timing of regulatory designs in some pathways are lower and less immediate than other pathways. For example, the scale and timing of renewable gas in High Electrification is lower and less immediate than Low Electrification. Similarly, the scale and timing of regulatory designs in some pathways is greater and more immediate than other pathways. For example, the scale and timing of regulatory designs related to 100% Gas Decommissioning is higher and more immediate than Efficient Gas Equipment.

As noted earlier, the regulatory designs include LDC transition plans and charting a course for future progress toward supporting the Commonwealth's achievement of the climate goals. In evaluating this regulatory design the Consultants assessment was based on the pathways that provide the LDCs with optionality to utilize technologies and fuels that rely on both the gas and electric systems.

Under all pathways, the LDCs, the D.P.U., and policymakers will need to manage customer costs and energy bills to ensure that the clean energy transition in Massachusetts is affordable and equitable to all. A coordinated gas and electric decarbonization strategy, utilizing a diverse set of technologies and strategies, is likely to be better able to manage the costs and feasibility risks of decarbonization than scenarios that rely more heavily on single technologies or strategies.