GSEP AT THE SIX-YEAR MARK

A REVIEW OF THE MASSACHUSETTS GAS SYSTEM ENHANCEMENT PROGRAM

Prepared for Gas Leaks Allies
by Dorie Seavey, PhD
October 2021

Report prepared by Dorie Seavey, PhD for Gas Leaks Allies. While Dr. Seavey participates in Gas Leaks Allies, a voluntary association, *GSEP at the Six-Year Mark* was written in her individual capacity and not as a participant of Gas Leaks Allies, nor on behalf of or with the endorsement of Gas Leaks Allies or any participating organization.

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Cite this document as:
Dorie Seavey, *GSEP at the Six-Year Mark: A Review of the Massachusetts Gas System Enhancement Program*, version 1.0, October 2021, https://gasleaksallies.org/gsep.

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About the Author

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About Gas Leaks Allies

The Gas Leaks Allies is a coalition of more than 30 organizations, researchers, and advocates focused on reducing methane emissions from the gas distribution system in Massachusetts while developing strategies for a just, equitable transition to carbon-free energy sources.

Our unconventional, interdisciplinary collaboration advances solutions to the problems caused by aging, leaking gas pipes buried in our neighborhoods. We address issues with leaking gas inside our homes, in our communities, and from the gas industry as a whole.

Driven by the urgency of the climate crisis and the need for a rapid, managed transition off gas, we work toward implementing carbon-free energy systems such as utility-scale geothermal networks that use water instead of gas to heat and cool our homes.

In all our work, we promote environmental justice, advocate for good jobs, and advance energy solutions that benefit rather than penalize low-income communities.

See gasleaksallies.org for additional information and a list of participants.

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Executive Summary

In response to the growing climate emergency, Massachusetts began establishing transformative decarbonization goals in 2008. Now, more than a decade later, the Commonwealth is at a critical crossroads with respect to creating a sustainable energy pathway forward to safely power our homes, businesses, municipalities, and industries. In 2014, the Commonwealth embarked on an ambitious program—the Gas System Enhancement Program (GSEP)—to replace leaking fossil gas infrastructure showing corrosion and cracking due to age. Each year, more than 14,000 new gas leaks in underground pipeline networks serving gas customers are detected and reported. These leaks not only present safety and health hazards, but also release methane (CH_4), an extremely potent greenhouse gas.

This report addresses the challenging dilemma presented by the current situation. On the one hand, Massachusetts must move rapidly towards a decarbonized future. On the other hand, a major, very costly, fossil gas infrastructure program—GSEP—is replacing substantial amounts of the Commonwealth's gas pipeline owned and operated by six investor-owned local distribution companies (LDCs). Looking back over the last six years, this analysis considers the outcomes of GSEP to date: how many miles of infrastructure have been replaced, how much the program is costing, and what progress has been made reducing fugitive gas. Next, this analysis projects the likely future costs of GSEP and considers the various pressures and constraints impacting pipeline costs for gas utilities. Finally, the report examines the degree of alignment between GSEP, the Commonwealth's mandated greenhouse gas limits, and the necessary and inevitable transition to renewable energy sources and a low-carbon economy.

Key findings of this report include:

1. **The total cost of GSEP is likely to top $20 billion**. This estimate is based on current, approved rates of return and unit costs, and assumes that GSEP-funded infrastructure is depreciated by 2050, the year that Massachusetts has targeted to achieve net-zero emissions. Costs of this magnitude would make GSEP one of the most expensive infrastructure projects ever undertaken in the Commonwealth —one rivaling the scale of the Big Dig.
2. **GSEP's effective time frame has been extended to 2039, bringing it dangerously close to the Commonwealth's mandated 2050 net-zero emissions deadline. Meeting even this revised timeline is increasingly unlikely.** Approximately 20 percent of the leak-prone pipe in the Commonwealth had been eliminated by 2020 but a quarter of the extended time frame had elapsed. Moreover, meeting the extended timeline assumes an infrastructure replacement rate for the largest LDC—National Grid-Boston Gas—that is both unrealistic and cost prohibitive, given the GSEP cost recovery system and the fact that the most complicated and expensive replacement projects within the Boston Gas territory have barely commenced.
3. **The increasing cost of pipeline replacement work may constrain the ability of LDCs to achieve their stated replacement goals due to the regulatory cap on LDC spending for GSEP.** As infrastructure replacement costs escalate, the "revenue cap" can be expected to become a significant factor constraining LDC replacement work because this cap limits the increment of new annual expenses that LDCs can recover through customer rate increases (the "revenue requirement"). As LDCs "max out" their revenue requirement with fewer, more costly replacement miles, they will be unable to keep up with the rate of infrastructure replacement needed to meet GSEP's timeline unless further extensions are approved.

4. **LDCs are likely to request unprecedented financial relief as GSEP proceeds, resulting in higher gas rates for customers.** As exemplified by the current rate case of National Grid-Boston Gas (DPU 20-120), LDCs can be expected to petition the DPU for two types of unprecedented financial relief due to the risks they find inherent in the current situation: (i) higher rates of return on equity, and (ii) accelerated rates of capital-cost recovery through depreciation. These requests reflect the gas industry's concerns about fully recovering its investments and attracting sufficient investment capital considering the transition underway to a low-carbon economy. If approved, each of these changes will necessarily raise customer gas rates through the medium term. Shorter asset lives will also put downward pressure on the longer-term earnings of gas companies.
5. **While 15,000 to 18,000 leaks have been repaired or eliminated in each of the last four years, each year has begun with a backlog of unrepaired leaks roughly equal to the number of leaks repaired or eliminated during the previous year.** In other words, for the Commonwealth as a whole, leak repair activity, at best, has only managed to keep up with the new leaks emerging each year.
6. **To date, the Commonwealth has not created incentives to strategically and successfully repair leaks and monitor those repairs.** The use of state-of-the-art monitoring and repair technologies by LDCs is hindered by the fact that the regulatory cost recovery system rewards pipe replacement, not repair, even though the life of a pipe can be significantly extended using advanced repair technologies that are more cost effective than traditional excavation and replacement.

GSEP has brought Massachusetts into an intensive, protracted gas infrastructure replacement cycle that today raises red flags. The program's original intent was sound: to enhance public safety and reduce the amount of methane leaked into the atmosphere by replacing leak-prone pipe on an accelerated basis. But the impact of the replacement activity on safety has been indeterminant, the sheer number of reported gas leaks has only minimally declined, and the three largest gas companies have so far been unable to meet the methane emission targets set by the Commonwealth's Department of Environmental Protection. Furthermore, GSEP has become one of the largest, most expensive infrastructure projects ever undertaken in Massachusetts and the program is not receiving the scrutiny, analysis, and evaluation it warrants given its mega-project status.

This report finds that GSEP **is in dire need of systemic, state-wide evaluation that carefully considers the aggregate impact of the program and the likely ramifications for both gas companies and ratepayers (the "public").** While the DPU has been the industry policymaker and regulator, the agency offers little in the way of proactive, publicly released, evaluative analysis of the six LDC GSEP plans taken together. As a result, **massive infrastructure decisions—totaling more than half a billion dollars annually—are being made in a piecemeal fashion.**

A comprehensive assessment of the program should also produce guidelines for vastly improved oversight and management of the LDCs by their regulator. Guidelines could include, for example, improved pipe and leak classification systems, clear and strategic criteria for prioritizing leak repair vs. pipe replacement projects based on both safety and climate-damage considerations, spending limitations ensuring that new GSEP costs are not incurred for projects that fail to meet prioritized repair/ replacement criteria, and rigorous program target goals and benchmarks tied to consistently measured and monitored metrics.

The report raises serious concerns about whether GSEP, taken as a whole, remains financially and programmatically sound. In 2021, $570.4 million is to be spent by the six LDCs to replace 266 miles of pipeline and approximately 15,300 services. Since 2015, 1,348 miles have been replaced, but more than

5,300 miles remain to be replaced by the program's target end date. Unit costs for the replacement of distribution pipeline have been increasing on the order of 17 percent annually for the largest LDCs. In 2020, these costs reached $2.6 million per mile for National Grid-Boston Gas, the largest LDC in the Commonwealth and the company responsible for about 60 percent of the state's leak-prone pipe. Replacement rates and depreciation practices have become unrealistic relative to the actual useful economic life of these pipelines, considering both the physical deterioration and technical obsolescence of the existing gas distribution infrastructure as well as the Commonwealth's mandated emission limits.

In sum, GSEP is on a course to generate unrecoverable costs, an outcome with the potential to create serious inequities for ratepayers. Lower-income households are likely to have the most difficulty switching to lower-cost, cleaner energy systems due to higher upfront costs and the likely reluctance of landlords to invest in weatherization and new thermal energy systems.

Safety must remain the essential priority of the gas companies and the DPU. T**he largest, most hazardous, and climate-damaging leaks need to be aggressively identified and fixed. To accomplish this goal, two underlying price regulation distortions must be corrected: GSEP's financial incentive to replace rather than repair leaking infrastructure should be reversed, and "lost gas" from leaks should no longer be treated as a normal cost of doing business to be entirely passed on to ratepayers.** These perverse incentives stand in the way of creating effective incentives to strategically and successfully repair leaks and to monitor those repairs.

The DPU's recently broadened mandate to balance equity, security, and reductions in greenhouse gas emissions with its longstanding priorities of safety, reliability, and affordability creates an immediate imperative for rethinking GSEP's "business-as-usual" approach to replacing gas pipes and associated infrastructure. The fact that GSEP is neither aligned or integrated with the Commonwealth's climate goals must be addressed: the underlying premise of GSEP—the indefinite continuation of the fossil gas distribution network—is irreconcilably at odds with the Commonwealth's climate-related mandates and the urgency of needed state policy action to dramatically reduce greenhouse gas emissions. Furthermore, Massachusetts' mandatory emissions reduction goals will inevitably require decommissioning at least some parts of the Commonwealth's fossil fuel infrastructure. But while the Commonwealth has set aggressive targets for building electrification, it has yet to establish targets for decommissioning the fossil fuel infrastructure that will be displaced by electrification.

The Governor, the Executive Office of Environment and Environmental Affairs, the DPU, and the legislature need to take a hard look at GSEP and its future viability in light of the significant market and policy forces reshaping our energy future. Much work remains to be done to determine how to efficiently, equitably, and safely create an energy transition for the Commonwealth that balances the interests of society at large, existing and future energy customers, and the shareholders of energy utilities. Rethinking GSEP offers an important opportunity for state government, utilities, and other investors to work together to shape the Commonwealth's energy transition by **redirecting GSEP financing away from sustaining an outdated, failing gas distribution system and toward investments in renewable, zero-emission energy for all.**

I. Introduction

In response to the growing climate emergency, Massachusetts began to establish transformative decarbonization goals in 2008. Now, more than a decade later, the Commonwealth is at a critical crossroads with respect to creating a sustainable energy pathway to safely power our homes, businesses, municipalities, and industries.

Today more than half of households in the Commonwealth depend on fossil gas (called "natural gas" by the industry) piped into our homes and businesses, and then combusted in burners, furnaces, stoves, water heaters, and clothes dryers.[1] In addition to *combusted fossil gas*, fugitive or uncombusted fossil gas escapes or leaks from corroded, pockmarked, and splintered pipes and gas meters and from joint connections.[2] In Massachusetts, the pipes carrying fossil gas are some of the oldest in the country, and a large portion of them have deteriorated and are compromised due to age. Each year since 2016, more than 14,000 new gas leaks are detected or reported in the underground pipeline networks serving homes, businesses, and industry.[3] These leaks present safety, health, and climate risks.

Leaked fossil gas is nearly pure methane (CH_4), a highly potent greenhouse gas with more than eighty times the climate warming impact of CO_2 over the first twenty years of its release into the atmosphere.[4] State and federal greenhouse gas inventories use gas leakage emission factors equal to roughly 1.1 percent of total fossil gas consumed in the Commonwealth, but atmospheric-based estimates find loss factors of two to three times this amount, suggesting that leaked gas may contribute more to global warming than the gas consumed in residences.[5] According to the Conservation Law Foundation, when the Massachusetts greenhouse gas inventory for 2016 is adjusted for the impact of gas leaks, 13 percent of the Commonwealth's greenhouse gas emissions are attributable to leaking gas infrastructure and an additional 15 percent of emissions are caused by the burning of fossil gas in residential, commercial, and municipal buildings.[6]

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[1] In 2018, the use of fossil gas in the residential sector along with that of the commercial and industrial sectors accounted for 26% of the Commonwealth's greenhouse gases attributable to combusted fossil fuels, up from 13% in 1990. Massachusetts Department of Environmental Protection, DEP Emissions Inventories, Statewide Greenhouse Gas Emissions Level: Proposed 1990 Baseline Update, Appendix C (Worksheet C02_FFC), https://www.mass.gov/lists/massdep-emissions-inventories.

[2] Significant leaks also occur upstream from local distribution systems at fracking facilities and wells, gas processing plants, compressor stations, and storage facilities. In other words, the entire fossil gas supply chain is a significant emitter of methane.

[3] See Appendix A (column 3) of the DPU's annual report to the Massachusetts Legislature in late December of each year entitled "Report to the Legislature on the Prevalence of Natural Gas Leaks in the Natural Gas System" (DPU 17-GLR-01 to 20-GLR-01). See note 20 below for details on how to access reports at the DPU's docket website.

[4] Even when measured over longer periods of 100 years, methane is 24 times more powerful than CO_2 emissions. G. Myhre, D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, "Anthropogenic and Natural Radiative Forcing," *in Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press, Cambridge, UK, and New York, NY, USA: 2014), 714, Table 8.7, https://www.ipcc.ch/report/ar5/wg1/.

[5] The state and federal emission factors do not include upstream leaks that occur before the gas enters local distribution networks which are in turn owned by gas companies that supply retail customers such as households, businesses, and municipalities.

[6] Conservation Law Foundation, *Getting Off Gas: Transforming Home Heating in Massachusetts* (Boston, MA: December 2020), 18, https://www.clf.org/publication/getting-off-gas/. Also, Kathryn McKain, "Methane emissions

In 2014, a state-wide fossil gas infrastructure replacement program—the **Gas System Enhancement Program (GSEP)**—was put in place by the Massachusetts legislature to address leak-prone fossil gas pipe over a twenty-year timeline.[7] This program allows utility companies to recover the costs of their infrastructure replacement work on an accelerated basis, with an annual cap limiting the amount of revenue each gas company can recover through increased tariffs billed to gas customers.

This report addresses the challenging dilemma presented by the current situation. It looks back over the last six years of GSEP to consider the program's outcomes: how many miles have been replaced, how much the program is costing, and what progress has been made reducing fugitive gas. It next considers the likely future costs of GSEP and the various pressures and constraints affecting pipeline costs for gas utilities. The degree of alignment between GSEP and the Commonwealth's mandated transition to renewable sources of energy and a low-carbon economy is also evaluated.

The remainder of this report is organized into five sections:

- Section II, Massachusetts' Fossil Gas Distribution System – The Basics, provides background and context regarding the overall fossil gas distribution system in Massachusetts.
- Section III, Gas System Enhancement Program – How It Works, examines the structure of the GSEP, how the program is paid for, and how cost recovery works. This section also presents information about the prioritization of pipeline replacement projects to date and examines how GSEP treats repairing pipes as opposed to replacing them.
- Section IV, GSEP Outcomes Through 2020, evaluates the observable outcomes of GSEP from its inception in 2014 through 2020.
- Section V, GSEP Looking Forward, turns to key future considerations about GSEP: the trajectory of the program's costs, whether the program will be able to meet its timeline, and the prospects for cost recovery. Also considered in this section is information about important changes in the relative costs of different forms of energy and the extent of the alignment between GSEP and the Commonwealth's climate goals and policies.
- Section VI describes the report's key findings and conclusions.

from natural gas infrastructure and use in the urban region of Boston, Massachusetts," *Proceedings of the National Academy of Sciences* (PNAS) 112, 7 (February 17, 2015): 1941-1946, https://doi.org/10.1073/pnas.1416261112.

[7] An Act Relative to Natural Gas Leaks, 2014 Mass. Acts 149, https://malegislature.gov/laws/sessionlaws/acts/2014/chapter149.

II. Massachusetts' Fossil Gas Distribution System – The Basics

Fossil gas is by far the predominant source of energy used in Massachusetts. More than half of the Commonwealth's households use gas to heat their homes.[8] Households, businesses, factories, and power-generating facilities—end users—depend on local fossil gas distribution systems to carry gas to them through 21,000 miles of pipeline mains and associated services buried underground.[9] A significant proportion of this infrastructure was installed a long time ago. In fact, Massachusetts has the second oldest gas infrastructure in the country, with some pipes installed more than one hundred years ago.[10]

Due to its age and various materials, roughly 30 percent of the mains in Massachusetts' fossil gas distribution infrastructure have been determined to be compromised.[11] This leak-prone pipe is made of cast iron, wrought iron, steel (bare and non-cathodically protected),[12] and Aldyl-A plastic. Massachusetts pipeline mains taken together have a leak ratio (i.e., leaks per mile of distribution pipeline main) that is approximately four times the national average.[13] In addition, about 20 percent of the more than 1.3 million services in the Commonwealth are considered leak-prone and as much as 60 percent of these are made of bare steel.[14]

The Massachusetts gas distribution system is divided into distinct service territories owned and operated by six investor-owned local distribution companies (LDCs)[15] and four municipal gas departments (see Figure 1).[16] At meter stations throughout the state, each of these distribution systems connects to larger interstate pipeline systems owned by transmission companies. All the fossil gas used by Massachusetts is

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[8] US Department of Energy, Energy Information Administration, "Massachusetts State Energy Profile," https://www.eia.gov/state/print.php?sid=MA.

[9] Mains are the pipelines that carry fossil gas from the meter stations throughout the distribution systems. Usually between 2 and 16 inches in diameter, mains are made of steel, plastic, or cast iron. The gas pressure ranges from 1/4 psi to 200 psi. Services carry the gas from the main to the customer's gas meter. These smaller pipes usually range from 1/2 inch to 1 1/2 inches in diameter and are made of steel, copper, or plastic pipe. The pressure in a service line is the same as the pressure in the main to which it is connected.

[10] The only state with even older gas infrastructure than Massachusetts is West Virginia.

[11] See Section IV. A. of this report.

[12] Cathodically-protected steel refers to steel that has been treated to control corrosion either by galvanic treatment or an impressed current.

[13] Dynamic Risk Assessment Systems, Inc., *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts*, commissioned by the Massachusetts Department of Public Utilities (January 29, 2020), 37, Table 9, https://www.mass.gov/doc/dynamic-risk-phase-2-rev-1/download. This calculation excludes leaks caused by excavation since this type of leak does not necessarily indicate that the pipe material was failing.

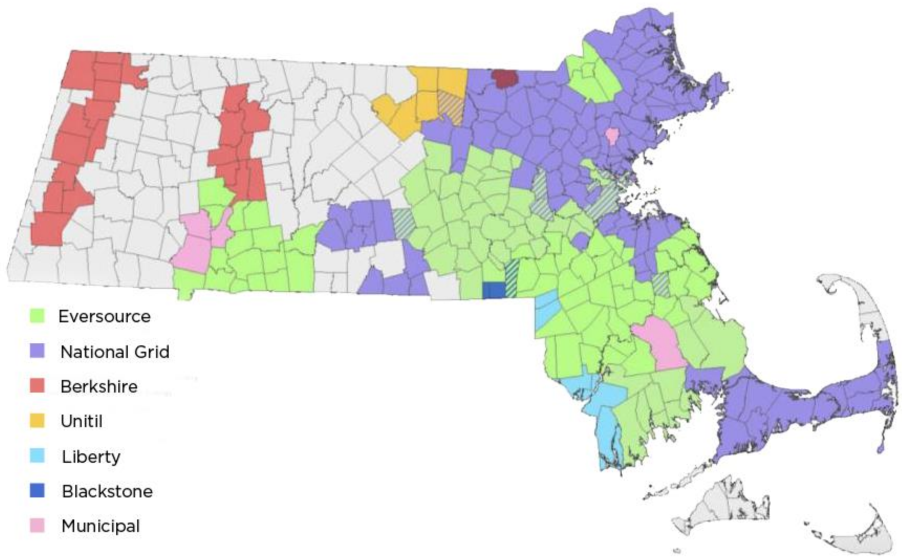
[14] US Department of Transportation, PHMSA, Gas Distribution Annual Data – 2010 to present (ZIP extracted for 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[15] See Table 1 for the list of investor-owned LDCs.

[16] Holyoke Gas & Electric, Middleborough Gas & Electric, Wakefield Municipal Gas & Light, and Westfield Gas & Electric Light.

imported from other states and more than 80 percent comes from fracking fields in western Pennsylvania.[17] Some fossil gas is imported as liquid natural gas or LNG.[18]

Figure 1: Gas utility territories in Massachusetts



Source: Cathy Kristofferson/PLAN-NE.

Like most utilities in the United States, LDCs operate as sanctioned monopolies, subject to regulation by state administrative bodies and federal authorities.[19] In Massachusetts, the **Department of Public Utilities (DPU)[20]** is responsible for gas utility price regulation, overseeing the service quality of local gas utility companies, and regulating the safety of gas pipelines. The DPU is also responsible for ensuring that gas utility consumers are provided with the most reliable service at the lowest possible cost. Climate legislation adopted in March 2021 expanded the DPU's scope to include equity, security, and the

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[17] Hydraulic fracturing (fracking) refers to a technique for extracting fossil gas or oil from bedrock by pressurized injection of large quantities of water, chemicals, and sand to crack the rock, thus allowing the gas or oil to escape. Environmental impacts include: groundwater and surface water contamination, water supply depletion, air pollution, triggering of earthquakes, with resulting impacts to public health and environmental degradation.

[18] US Energy Information Administration, "Liquified natural gas imports limited price spikes in New England this winter," *Today in Energy* (May 13, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39432. New England receives LNG imports from three regional regasification facilities: the Canaport LNG onshore terminal in New Brunswick, Canada; the Everett LNG onshore terminal, near Boston, Massachusetts; and the Northeast Gateway Deepwater Port offshore terminal, also near Boston.

[19] Janice A. Beecher, "Economic Regulation of Utility Infrastructure," Lincoln Institute of Land Policy (Cambridge, MA: May 2013), https://www.lincolninst.edu/publications/conference-papers/economic-regulation-utility-infrastructure.

[20] The various Massachusetts Department of Public Utility (DPU) dockets for the six gas operators with GSEP orders can be accessed at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber. In this report, citations to specific documents filed in GSEP-related dockets follow this syntax: "DPU (last two digits of year of filing)-(acronym for docket)-(LDC identifier)" – e.g., "19-GSEP-01" or "20-GREC-06." The LDC identifiers 01 through 06 refer, respectively, to the following companies: Unitil, Berkshire Gas Company, National Grid, Liberty Utilities, Eversource Gas of Massachusetts, and Eversource NSTAR.

reduction of greenhouse gases consistent with Massachusetts law.[21] By statute, the **Office of the Attorney General** represents the interests of consumers in matters involving the pricing and delivery of fossil gas and works to ensure that Massachusetts businesses and residents have access to reliable, safe, and affordable energy. The Office of the Attorney General actively participates in all GSEP-related DPU proceedings. The **Department of Environmental Protection** has regulatory oversight over the gas system's fugitive emissions and LDCs must file annual reports detailing their estimates of their methane emissions.[22] At the federal level, interstate pipelines are regulated by the **Pipeline and Hazardous Material Safety Administration (PHMSA) of the US Department of Transportation Division of Pipeline Safety.** LDCs must file annual reporting with PHMSA detailing the composition of their infrastructure and leaks by material and cause.[23]

The effort to address leaking gas infrastructure in Massachusetts dates back three decades to 1991 when the Department of Public Utilities (DPU) prohibited the installation of cast iron pipe after April 12, 1991 (220 CMR 113.00). The same regulation also required each LDC to develop and implement cast iron replacement programs and immediately replace or abandon cast iron pipe when third-party excavation occurs nearby.[24]

Beginning in 2009, the DPU began approving **"targeted infrastructure replacement factor programs" (TIRF programs)** to accelerate the repair or replacement of certain types of aging infrastructure and leak-prone pipe. Like the current Gas Safety Enhancement Program (GSEP), the TIRF programs allowed LDCs to recoup their infrastructure spending outside of their normal rate cases via an annual reconciling mechanism, thus allowing for expedited cost recovery.[25]

Three companies participated in the TIRF program: National Grid-Boston Gas and Colonial Gas, Bay State Gas Company, and Liberty Utilities. Between 2010 and 2013, these companies replaced what the DPU termed "significant amounts of leak-prone infrastructure": 691 miles of mains and 21,042 services.[26] Looking over a longer period spanning 1999 to 2013, a report prepared for the DPU by the consulting firm ICF International in 2014 found that "[s]ince 1999, 25 percent of leak-prone mains and 53 percent of leak-prone services have been replaced in Massachusetts. Leak-prone mains have steadily been replaced over this 15-year period, and leak-prone services were replaced at an accelerated rate for the first 5 years

[21] An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts 8, Section 15, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8. Note: The legislation defines "equity" with reference to the protection of low- and moderate-income persons and environmental justice populations.
[22] 310 CMR 7.73, Reducing Methane Emissions (CH4) from Natural Gas Distribution Mains & Services. This regulation establishes gas operator annual declining emission limits for 2021, 2022, 2023, and 2024.
[23] PHMSA also has authority to regulate the pipeline material used by LDCs.
[24] 220 CMR, Section 113.06 and 113.07. Third-party excavation is called "encroachment" and refers to third-party exposure and undermining of a utility pipeline due to parallel excavation or trench digging.
[25] The "revenue requirement" is a reconciling mechanism that allows utilities to recoup depreciation, return on investment, and property taxes. See Section III. C. of this report for further explanation.
[26] DPU 20-GLR-01, 12 and note 17. Of note, this replacement rate is very similar to the GSEP replacement rate during the past three years (2019 through expected 2021).

and slowed down for the past 10 years."[27] An accounting provided in the report shows an inventory of leak-prone mains in 1999 of roughly 7,000 miles, declining to 5,300 in 2013.[28]

With the initiation of GSEP by the Massachusetts Legislature in 2014, the DPU appears to have reset its count of the inventory of leak-prone mains to 6,023 miles.[29] This recalibration presumably reflected the fact that the inventory of compromised pipe is constantly changing as pipes continue to age and different types of pipe material exhibit signs of deterioration. According to the gas industry and the DPU, plastic pipes are the latest type of pipe material to show failure, specifically pipes made of Dupont Aldyl-A Polyethylene plastic.[30] This type of plastic pipe was used from the 1960s through the early 1980s and has been found by the gas industry to have potential for splintering. The current replacement pipe material used by the LDCs is polyethylene (PE) plastic pipe. PE plastic is favored because of its relatively non-corrosive properties although it is susceptible to excavation damage.[31]

[27] ICF International, *Lost and Unaccounted for Gas*, prepared for the Massachusetts Department of Public Utilities (Cambridge, MA: December 2014), B-3, https://www.mass.gov/doc/icf-international-report-lost-and-unaccounted-for-gas/download.

[28] ICF International, *Lost and Unaccounted for Gas*, prepared for the Massachusetts Department of Public Utilities (Cambridge, MA: December 2014), Figure B-1, https://www.mass.gov/doc/icf-international-report-lost-and-unaccounted-for-gas/download. By time of the initiation of GSEP in 2014, the DPU had reset the inventory of leak-prone mains to 6,023 (DPU 17-GLR-01, note 7).

[29] DPU 20-GLR-01, note 6. The same figure of 6,023 miles is reported in the first DPU report on gas leaks delivered to the legislature on December 17, 2017 (DPU 17-GLR-01, note 7).

[30] As will be explained in the next section of this report, since 2014 the DPU has authorized the inclusion of additional miles of leak-prone pipe beyond the initial GSEP inventory of 6,023 miles of leak-prone main. However, the DPU has not provided a precise accounting of the current running total. The attorney general has consistently opposed the inclusion of Aldyl-A pipe in the GSEP inventories of LDC leak-prone infrastructure on several grounds including that plastic mains are not GSEP-eligible infrastructure under M.G.L. ch.164 § 145; they are not among the top risks identified in LDC DIMPs; and they lack a record of leaks in LDC distribution systems. In addition, the attorney general argues that such a classification will divert GSEP resources from the replacement of far more risky facilities and important GSEP projects and that LDCs should recover the cost of any Aldyl-A infrastructure replacement through traditional cost recovery and not GSEP. See, for example, DPU 18-GSEP-05, AGO Initial Brief 3-18-19, 19-22.

[31] American Gas Association, *Report to America on Pipeline Safety Determining Natural Gas Distribution Fitness for Service* (2011), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/FFS-%20Distribution%20Technical%20Note%20Proposal%20Final%20%282%29.pdf.

III. Gas System Enhancement Program (GSEP) – How It Works

In 2014, the Massachusetts Legislature passed **An Act Relative to Natural Gas Leaks** (M.G.L. ch.164 § 145) which prescribed the **Gas System Enhancement Program (GSEP).** The statute establishes GSEP as a voluntary, long-range infrastructure replacement program for the gas distribution systems owned and operated by LDCs with a defined end goal, namely the elimination of leak-prone mains and services on LDC distribution systems. The original timeline for the program was twenty years (ending in 2034), but that timetable has now been effectively extended to 2039 because of extensions granted to the two largest gas companies.[32] These extensions bring the program's end to within a decade of the Commonwealth's mandated net-zero target year of 2050.

By enacting the new GSEP law, the legislature sought to accelerate the pace of pipeline replacement. The stated goals of the program are to improve public safety, promote infrastructure reliability, and protect the environment by reducing lost and unaccounted for gas (LAUF) through the reduction of gas leaks. GSEP allows LDCs to recover their capital expenditures on infrastructure replacement of leak-prone mains, services, and other facilities through a reconciling mechanism outside of the DPU-administered process for setting the base rates charged to gas customers. Part of the program's rationale is to enable LDCs to plan ahead by negotiating multi-year contracts with contractors (presumably on more favorable financial terms) and instituting multi-year procurement plans for needed supplies and equipment.

A. Participating companies and their leak-prone pipe inventory

All six investor-owned LDCs in Massachusetts have been participating in GSEP and, to date, seven consecutive years of LDC annual GSEP plans have been approved by the DPU.[33] Table 1 lists the participating companies.

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[32] The three smallest companies report that they are on track to achieve their targeted replacement goals by 2034 or earlier (Berkshire Gas, Liberty Utilities, and Unitil). The two largest gas companies have received extensions from the DPU: National Grid and Eversource NSTAR. National Grid-Boston Gas and National Grid-Colonial Gas received five-year and two-year extensions, respectively (to 2039 for the former and 2036 for the latter), and Eversource NSTAR received a five-year extension to 2039. Additionally, in its Comprehensive Safety Assessment & Implementation Plan filed with DPU on September 1, 2021 (DPU 21-109), Eversource Gas of MA indicated that it may not be able to complete its pipeline replacement by 2034: "The current EGMA GSEP plan does complete the work within the required 20 years, but the high concentration of priority pipe in the Springfield area work center does create a risk to executing the plan due to the concentration of work in the later years. Limited workforce availability and restrictions to project permits are both potential problems which would result in extending the program beyond the 20-year timeline." See DPU 21-209, Exhibit EGMA-WJA/JPD/JKD-2, 22. (The filing of this safety plan was called for as part of the settlement agreement that allowed Eversource to acquire the assets of the former Bay State Gas Company.) It should be noted that the authorizing legislation (M.G.L. ch.164 § 145(c)) allows for a "target end date" of "not more than 20 years" OR "a reasonable target end date considering the allowable recovery cap." The latter presumably allows for a slower rate of infrastructure replacement to soften the impact on retail gas rates. See Section III of this report for further explanation.

[33] The most recent DPU orders can be accessed at: https://www.mass.gov/lists/gseps-pursuant-to-2014-gas-leaks-act. The DPU conducts an annual docket process upon the filing by gas operators of their annual plans under GSEP. The DPU approves the scope of total pipe repair and replacement work for each gas operator for each calendar year by April 30 of that same year.

Table 1: Investor-owned gas utilities participating in GSEP

Berkshire Gas Company
Eversource NSTAR
Eversource Gas Company of Massachusetts (formerly Bay State Gas dba as Columbia Gas of Massachusetts)[1]
Liberty Utilities (Fall River/North Attleboro/Blackstone)[2]
National Grid (Boston Gas Company/Colonial Gas Company)[3]
Unitil (Fitchburg Gas and Electric Light Company)

Notes:

[1] In October 2020, the Department of Public Utilities (DPU) approved a Settlement Agreement authorizing the sale of Bay State/Columbia Gas Co. to Eversource Energy with its nearly 5,000 miles of pipeline. The name for Bay State Gas/Columbia Gas of Massachusetts is now Eversource Gas Company of Massachusetts.

[2] In October 2020, DPU approved the acquisition of Blackstone Gas Company by Liberty Utilities with its 55 miles of pipeline. The acquisition closed on December 31, 2020. The name for Blackstone Gas Company is now Liberty Utilities.

[3] Colonial Gas Company merged into Boston Gas Company on as of March 15,2020 and no longer exists as a separate legal entity. However, for rate-making purposes there are separate rates for the customers of Boston Gas and the former Colonial Gas. See DPU 19-69, p. 9.

According to the DPU, as of 2014, the original inventory of pipe to be replaced under GSEP consisted of 6,023 miles of legacy infrastructure. Legacy infrastructure refers to mains, services, meter sets, and other ancillary facilities composed of cast iron, wrought iron, and non-cathodically protected steel. In 2014, the LDCs participating in GSEP reported a total of 20,028 miles of main in their annual reports to PHMSA which means that at GSEP's inception, approximately 30 percent of the pipeline owned by LDCs was categorized as leak-prone.[34] Since this original tally, some LDCs have received approval from the DPU to add their Aldyl-A plastic pipes installed before 1985 to their inventory of leak-prone pipe slated for replacement—this accounts for at least an additional 742 miles of pipe to be replaced.[35] Pipe

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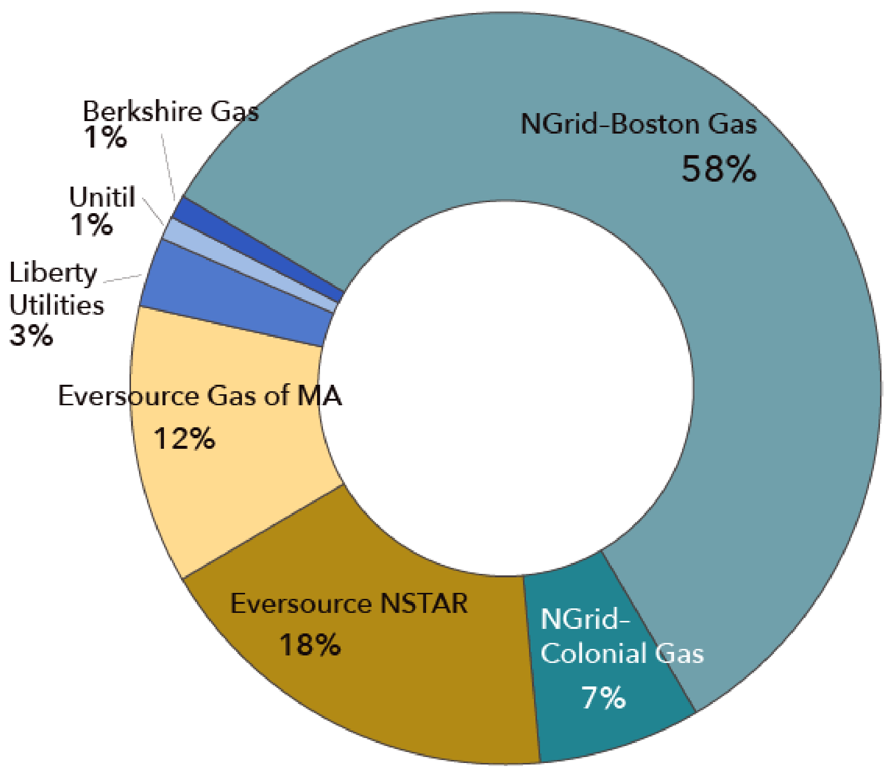
[34] US Department of Transportation, PHMSA, Gas Distribution Annual Data – 2010 to present (ZIP extracted for 2014 and 2020), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[35] National Grid-Boston Gas and National Grid-Colonial Gas, Liberty Utilities, Eversource Gas of MA, and Eversource NSTAR report that their pipeline networks contain Aldyl-A plastic pipe which is known to have integrity concerns. The DPU has approved including this pipe in GSEP-eligible leak-prone infrastructure of these companies. As of 2019, **National Grid** reports 380 miles of this pipe (DPU 21-GREC-03, Exhibit NG-AS-6, p. 2) and **Liberty Utilities** reports 6 miles (DPU 20-GSEP-04, Exhibit LU-NJS-NMW-2, 5). In addition, the DPU approved the inclusion of Aldyl-A pipe for **Eversource Gas of MA** in 18-GSEP-05, 39-40), but the total number of miles of this type of pipe is not provided nor is it provided in the DPU's latest reporting of leak-prone pipe provided to the legislature in 20-GLR-01. Eversource Gas of MA's 2020 emissions report to the DEP under 310 CMR 7.3 indicates that this additional pipe could total as much as 342 miles (calculation of Gas Operator Emissions for 310 CMR 7.73 for Eversource Gas of MA provided to the author by MassDEP). Finally, **Eversource NSTAR** reports

reclassification (e.g., from cathodically-protected steel to unprotected steel) is another factor that can change the reported inventory of leak-prone pipe in the gas distribution system.[36]

Using the information reported in the DPU's latest report to the legislature on the prevalence of gas leaks,[37] Figure 2 gives a rough breakdown of the distribution of leak-prone mains across the different LDCs participating in GSEP. Nearly 60 percent of total leak-prone mains in Massachusetts are located in the National Grid-Boston Gas service area (the vast majority of that leak-prone pipe is in the greater Boston area where work is particularly challenging because of the density of buildings and streets).

Figure 2: Percent of total remaining leak-prone gas mains owned by each local distribution company at end of 2019



Source: Author's calculations based on DPU 20-GLR-01.

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that, beginning with its 2019 GSEP, it is classifying Aldyl-A pipe installed prior to 1985 as elevated risk infrastructure appropriate for replacement under GSEP (see DPU 20-GSEP-06, Exhibit ES-RJB-1, 7). The DPU approved this classification in its order in DPU 18-GSEP-06. On page 33 of this order, the amount of qualifying Aldyl-A pipe in the Eversource NSTAR system is stated as "1,878,695 feet" or 356 miles. DPU 20-GLR-01 does not appear to include Eversource NSTAR's Aldyl-A pipe in its tally of leak-prone pipe for this company (pp. 21-22).

[36] See the end of Section IV.C of this report for information about a possible significant reclassification of pipe by National Grid from cathodically protected to non-cathodically protected (i.e., leak prone).

[37] DPU 20-GLR-01, 16-22.

The next largest concentration is in the Eversource service area. Eversource Gas of Massachusetts (the former Bay State/Columbia Gas Company) together with Eversource NSTAR account for an additional 30 percent of leak-prone pipe in the LDC system.[38]

It should be noted that the DPU's latest annual report to the legislature does not provide a clear tabulation of LDC leak-prone infrastructure by pipe material. The various data provided in the report suggest that, as of the end of 2019, a total of 5,281 miles of leak-prone distribution mains remained in the investor-owned LDC gas distribution system. However, this total does not appear to include the amounts of Aldyl-A plastic pipe that the DPU previously approved for inclusion in the leak-prone pipe inventories of Eversource Gas of Massachusetts and Eversource NSTAR. The inclusion of this pipe would increase the total count of leak-prone distribution pipe in the Commonwealth by perhaps as much as 500 miles, raising the percentage of leak-prone pipe in the system by roughly 10 percent, and changing each LDC's share of total leak-prone pipe.[39]

Regarding services, missing data for some LDCs in the DPU's latest annual report prevent the calculation of the number of remaining leak-prone services in the Commonwealth at the end of 2019.[40] Gas distribution annual data reported by the LDCs to PHMSA indicate that there were approximately 263,086 leak-prone services remaining in the LDC gas networks at the conclusion of 2019, or 19 percent of total services at the time.[41]

B. How GSEP is paid for

The cost of infrastructure replacement under GSEP is borne by the gas customers (i.e., the ratepayers) of each LDC. GSEP expenses—such as company labor, distribution system materials (pipes, meters, etc.), contractor charges, road surface restoration, police, traffic security detail, road opening permits, and environmental permitting—are considered expenditures that create new assets and, therefore, their financial impact is spread (i.e., amortized) over the useful life of the asset.

To give an example of this amortization, assume an LDC undertakes $100 million of pipeline replacement work in 2021 and that the pipes have a service life of thirty years. Each year for thirty years, the LDC will seek to recover two main cost items from its ratepayers: a depreciation expense equal to 1/30 of $100 million and a rate of return on the undepreciated balance of the investment (in Year One, the rate of return times 29/30 of $100 million). Various other adjustments are made to this calculation, including recovery

[38] The incidence of leaks across the different LDCs is nearly identical to the prevalence of leak-prone mains: 61% of total leaks on the system in 2019 occurred in the National Grid system (Boston Gas and Colonial Gas) and a third of the leaks were attributable to the Eversource system.

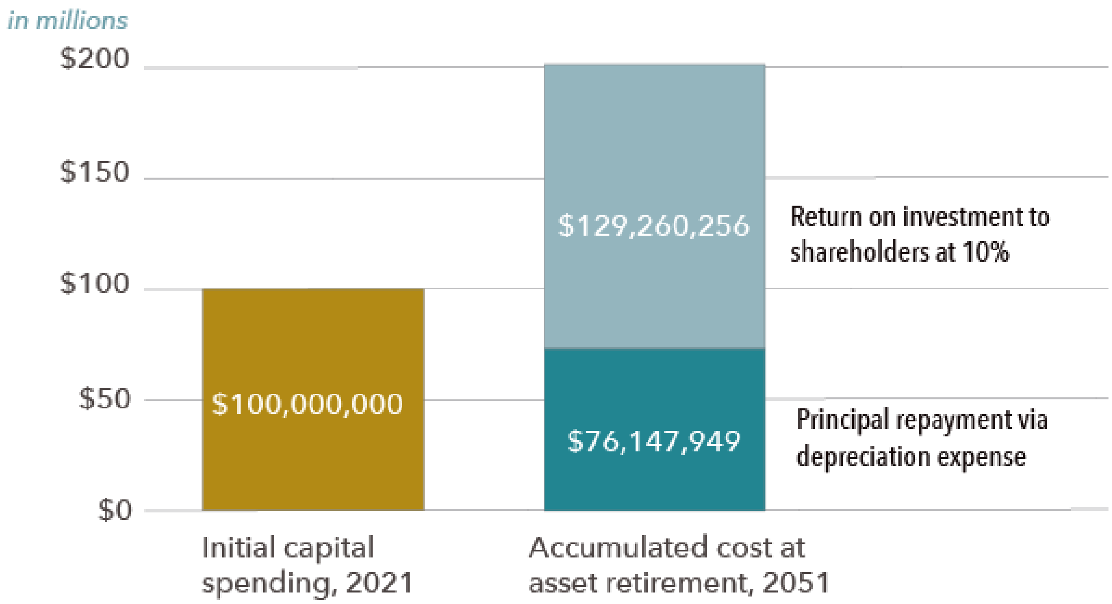
[39] DPU 20-GLR-01 presents the DPU's most recent annual gas leaks reduction report to the legislature covering the year 2019. Section III of that report, "Pipeline Replacement Programs," reports on the infrastructure replacement work of each LDC and describes their leak-prone pipe inventory (see pages 16-22). The reporting presents an inconsistent mix of total numbers of miles and percentages of leak-prone material across the companies. No summary table or detail is provided on the composition of pipeline replaced in the reporting year nor its age. Additionally, the report does not mention the totals of Aldyl-A plastic pipe that the DPU has authorized for inclusion in the leak-prone pipe inventories of Eversource Gas of MA (an unknown quantity with a maximum possible amount of 342 miles) and Eversource NSTAR (356 miles) (see note 35 above).

[40] Data is missing for National Grid-Boston Gas, National Grid-Colonial Gas, and Eversource NSTAR.

[41] US Department of Transportation, PHMSA, Gas Distribution Annual Data – 2010 to present (ZIP extracted for 2019), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

of property tax expenses.[42] Assuming a 10 percent annual rate of return and a 2 percent acceleration rate for inflation (and ignoring other adjustments), Figure 3 illustrates how the $100 million of capital spending in 2021 results over time in $205.4 million of costs to be recovered from the LDC's ratepayers (measured in today's dollars). In other words, for every dollar spent on new pipeline infrastructure, ratepayers incur an obligation to pay back two dollars by the end of the cost recovery period.

Figure 3: Example of utility cost recovery for a $100 million capital expense (2021 dollars)



Note: The inflation-adjusted value of the initial $100 million investment is $76.1 million in 2051.

One of the main components driving total amortized GSEP costs is the **rate of return earned by each LDC (and its investors) on its infrastructure investments**, a key variable decided by the DPU during the LDC's rate case.[43] Table 2 shows the current rates of return authorized by the DPU for each LDC. The average rate of return realized across Massachusetts LDCs in 2020 was 9.82 percent.[44]

[42] A few other adjustments are typically made as well, partially offsetting GSEP savings amounts for deferred tax reserves and operating and maintenance cost savings due to decreased leaks.
[43] The rate base is the value of property on which a public utility is permitted to earn a specified rate of return. During a utility's rate case, the rate base is determined along with the rate of return based on a capital asset pricing model. Also determined are the retail rates that consumers will be charged for the gas services they receive. Under M.G.L. ch.164 § 94, gas utilities must file a rate case with the DPU not less frequently than every ten years.
[44] Authorized LDC rates of return in Massachusetts appear to be in line with such rates nationally. See Lisa Fontanella, "A Deep Dive into US Gas ROE Authorizations in 2019," *S&P Global Market Intelligence* (February 18, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/research/a-deep-dive-into-us-gas-roe-authorizations-in-2019. According to this Standard & Poors analysis, the average return on equity (ROE) authorized for gas utilities in rate cases in 2019 was 9.71%: "There were 32 gas ROE determinations in 2019 rendered in 19 states, including in Louisiana by the New Orleans City Council. The ROE determinations authorized by state utility commissions during this period ranged from 9.0% to 10.25%, with a median of 9.70% and an average of 9.71%. Three public utility commissions had ROE authorizations of 10% or above: California, Georgia, and Wisconsin. Only one commission, New York,

Table 2: DPU authorized rates of return on LDC infrastructure spending, 2020

Gas Company	**Rate of return***
Unitil	9.98%
Berkshire	10.30%
National Grid-Boston Gas	8.90%
National Grid-Colonial Gas	9.07%
Liberty Utilities	9.79%
Eversource Gas of MA	9.67%
Eversource NSTAR	11.06%
AVERAGE	**9.82%**

*Authorized rates include a "gross-up" factor to compensate companies for federal and state taxes.

Sources: DPU 21-GREC-01, Exhibit Unitil-CGDN-2, Schedule 4; DPU 21-GREC-02, Exhibit BGC-JB/RG-2, Schedule 3; DPU 21-GREC-03, Exhibit NG AFS/CSS-4, 33; DPU 21-GREC-04, Exhibit LU-JMS-2, Schedule 3; DPU 21-GREC-05, Exhibit EGMA/RWF-1, Schedule 5; DPU 21-GREC-06, Exhibit ES-RWF-1, Schedule 30.

Underlying these rates of return is a weighted average cost of capital calculation that distinguishes the portion of the capital due to long-term debt (i.e., bonds) versus equity, a split generally in the 50/50 range for gas utilities. These two components have distinct rates of return from which a weighted rate is calculated.[45] The last step taken is to gross up the weighted rate to account for federal and state income tax rates, thus adjusting the final rate of return to a tax free (or "pre-tax") basis to allow LDCs to recover their income tax obligations on earnings resulting from the new gas infrastructure.[46]

At least every ten years, utilities must petition the DPU to conduct a rate case in which, among other things, they can seek changes to their return on equity. For example, National Grid-Boston Gas has a rate case in process (DPU 20-120) and is seeking an increase in its return on equity from 9.5 percent to 10.5 percent.[47] If approved by the DPU, this would raise the company's pre-tax overall rate of return from the current 8.9 percent to 9.52 percent. In making its case for the increase in its return on equity, National Grid-Boston Gas states that "[t]he uncertainty and risk associated with the decarbonization plans in Massachusetts has [sic] a significant effect on the ongoing business operations of the Company and other

had an ROE authorization of 9%, and there were no commissions that authorized an ROE below 9%." The author comments that "[w]hile edging slightly upward, the average gas ROE is still hovering around historic lows."

[45] For LDCs, the reported interest rates attached to the debt portion range from 4.13% to 6.71%, while the returns on equity vary from 9.5% to 9.9%.

[46] As an example of the gross-up calculation, assume a debt/equity ratio of 50/50 percent with returns to long-term debt and equity of 5% and 9.7%, respectively. This yields a weighted cost of capital of 7.35%. Current federal and state tax rates are 21% and 8%, respectively. To gross up the weighted cost of capital by the tax rate, multiply 7.35% by one minus the effective state and federal tax rate of 27.32%. This results in a "pre-tax" rate of return of 10.11%.

[47] DPU 20-120, Exhibit NG-AEB-11, 1.

natural gas distribution utilities in Massachusetts and increases the overall risk of operating these utilities."[48] The company also emphasizes that it faces increased operating and financial risk due to the prospect of additional (primarily safety-related) regulations and the associated likely increases in operational costs.[49]

C. How cost recovery works

Once the DPU approves an LDC's annual GSEP, starting May 1st of the following year the LDC can begin to recover the estimated costs of the projects included in the plan and a rate of return on these investments. A "revenue requirement" calculation is presented by the company to the DPU for approval based on the full legacy of GSEP infrastructure investments made since the company's last base rate case. The requirement essentially is a dollar amount that determines how much revenue the utility is authorized to bring in each year through tariffs added on to customer gas rates. That dollar amount consists of annual depreciation expenses, a rate of return times the undepreciated rate base for that year, property tax expenses, plus various other adjustments.

GSEP legislation (M.G.L. ch.164 § 145f) puts a cap on the revenue requirement eligible for recovery (the "revenue cap"). The cap was initially set at 1.5 percent of total firm revenues, including gas revenues attributable to sales and transportation customers, but beginning in April 2019, the DPU has allowed increases to the cap up to 3 percent.[50] The DPU also has the authority to approve a revenue requirement in excess of the cap to be deferred for recovery in subsequent years.[51] The revenue cap plays an interesting role in GSEP program. The practical intent of the cap is to create a bill-impact limit to shield ratepayers from potential billing impacts that would exact undue hardship, but the cap can also have the effect of limiting or putting a brake on LDC cost recovery and thus ultimately on the pace of infrastructure replacement.

Once the revenue requirement has been determined, a set of tariffs is calculated called the Gas System Enhancement Adjustment Factor (GSEAF). Relying on forecasts of gas consumption, the GSEAF is derived to recover the revenue requirement by allocating it to different ratepayer classes, such as

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[48] DPU 20-120, Exhibit NG-AEB-1, 62. When referring to "decarbonization plans," National Grid-Boston Gas specifically cites the DPU's 20-80 process (see Section V. E. of this report, "Can GSEP be aligned with state climate policy?") and the *Clean Energy and Climate Plan for 2020*, prepared by the Massachusetts Executive Office of Energy and Environmental Affairs (2015), https://www.mass.gov/service-details/clean-energy-and-climate-plan-for-2020.

[49] DPU 20-120, Exhibit NG-AEB-1, 64.

[50] The 3% cap on annual revenue is calculated as the product of (1) the historical average cost of gas per therm from the period starting in 2013 and ending with the most recent year that actual data is available, and (2) the average of weather normalized sales from the period starting in 2013 and ending with the most recent year that actual data is available.

[51] A recent example of deferral occurred for Liberty Utilities. Liberty exceeded its 3% revenue cap for 2021 by approximately $1 million and the DPU allowed this overage to be deferred to a subsequent GSEP recovery period, adding to other such amounts previously deferred. The potential rate impact of these deferrals is non-trivial, as indicated by the company's answer to a request for information by the attorney general. According to the company, "[i]f the total deferred revenue was included for recovery… [this would] result in an average monthly increase of $10.37 and 8.99%" for the typical residential heating customer (DPU 20-GSEP-04, AG-5-3, 1). The attorney general objected to this most recent deferral, arguing that the DPU should limit Liberty's GSEP replacements to the number of miles that would have allowed the company to comply with its revenue cap. See DPU 20-GSEP-04, Order 4-29-21, 11-20.

residential and commercial low-load or high-load. The tariffs are charged as a component of the Local Distribution Adjustment Factor (LDAF) on customers' bills.[52] In November of the year following a GSEP investment year, a reconciliation adjustment occurs that establishes the difference between revenue requirement and the actual billed revenue resulting from the GSEAF. A Gas System Enhancement Reconciliation Adjustment Factor (GSERAF) is then calculated, which, subject to approval by DPU, allows the LDC to make any reconciliation adjustment amount through the LDAF.

An important development in ratemaking for LDCs in Massachusetts is the prospect of more widespread use of performance-based ratemaking (PBR) plans. Traditional ratemaking is based on a cost of service/rate of return method and a test year is used to estimate cost of service and base rates. A PBR plan is designed to shift attention from costs and inputs to performance and outcomes. It typically allows for annual automatic adjustment of rates in accordance with a revenue cap formula as well as scorecard metrics and performance benchmarks that the utility must achieve.[53] A ten-year PBR plan was approved for Eversource NSTAR on October 30, 2020 (DPU 19-120). Currently, National Grid-Boston is petitioning for a five-year PBR plan (DPU 20-120). The implications of PBR plans for GSEP are not yet clear.

D. How pipeline replacement projects are prioritized

The GSEP statute (M.G.L. ch.164 § 145c) directs that pipeline infrastructure eligible for replacement is to be "prioritized to implement the federal gas distribution pipeline integrity management plan ("DIMP") submitted to the US Department of Transportation."[54] Federal regulation in turn requires each LDC to present its Distribution Integrity Management Plan (DIMP) in a written procedure that lays out a risk-based assessment of its distribution system.[55] This assessment must evaluate potential threats to the system in seven categories relating to the structure and integrity of the pipes: corrosion, natural forces, excavation damage, other outside force damage, material and weld failure, equipment failure/malfunction, and inappropriate operation.

When selecting replacement projects, LDCs appear to balance risk mitigation with operational considerations and local ordinance compliance and regulatory mandates. They also seek to coordinate with municipal infrastructure and paving projects, for example, waiting to undertake replacement work until a concentration of high-risk pipeline segments is identified within a circumscribed area in order to avoid the costs of repeated paving and street restoration.

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[52] DPU Consumer Information, Natural gas tariffs and delivery rates, https://www.mass.gov/service-details/natural-gas-tariffs-and-delivery-rates.

[53] Both types of ratemaking protocols allow for mechanisms called "capital trackers" to play a critical role in removing cost and/or revenue recovery to a separate rider or tariff where cost recovery is more frequent than rate cases. (GSEP is a kind of capital tracker). Capital trackers can be used to collect new costs not included in base rates or true ups of revenues or expense items from levels that differ from the test year. They often have the effect of shifting risk from the utility to the ratepayer. For an overview of issues associated with capital trackers, see: David E. Dismukes, PhD, "Regulation and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms," National Association of Regulatory Utility Commissioners, Advanced Training Workshop (September 29, 2010), https://www.lsu.edu/ces/presentations/2010/DISMUKES_MSU-IPU-TRACKER_4.pdf.

[54] DIMPs are submitted to the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the US Department of Transportation.

[55] 49 CFR Part 192, Subpart P, Gas Distribution Pipeline Integrity Management.

Here is National Grid's description of its prioritization method from its 2020 GSEP: "Consistent with the DIMP, National Grid prioritizes leak-prone pipe main segments for replacement based upon consideration of, among other things, leak repair history, types of leaks, pipe material, surrounding geography, segment length, nearby construction activity, field conditions, customer issues, open leaks, and engineering judgment... This procedure includes the impact of risks associated with the various classes of pipe material and diameter as outlined in National Grid's DIMP."[56]

Here is how Eversource Gas of Massachusetts describes its selection process for its 2020 GSEP projects: "The Company utilizes a balanced approach of (1) risk mitigation; (2) system reliability; (3) operational considerations; and (4) local ordinance compliance and regulatory mandates, with an emphasis on risk mitigation when developing and prioritizing its infrastructure replacement projects."[57]

In a 2020 report commissioned by the DPU, Dynamic Risk Assessment Systems, Inc. (DRA) found that, while LDC DIMP plans "appear to meet the minimum compliance requirements, most of the Gas Company DIMPs did not appear to have many of the characteristics of an actively used distribution integrity plan demonstrating continued learning and evolution of the program."[58] DRA underscored the importance of correctly prioritizing pipeline infrastructure to be replaced in order to stay ahead of the pace of deteriorating infrastructure and to achieve maximum impact on the incidence and extent of leaks. DRA recommended that LDCs consider three critical variables when prioritizing pipeline replacement: "1. Is the right volume of work being done over time? (Pace); 2. Is the right work being prioritized to drive down leaks? (Trajectory); and 3. How is the potential consequence of failure considered in the decision process? (Risk Reduction)."[59] The best metric for assessing pace and trajectory, according to DRA, is leak ratios (e.g., new leaks per mile over a specified period) monitored over time. When pipeline projects are appropriately prioritized, "[l]eak ratios should decrease over time, indicating a reduction in overall system risk and an increase in asset condition."[60] DRA further notes that one would expect projects in dense population locations to correspond to the areas where the leak ratios and potential hazards posed by fugitive gas are at their highest in terms of adverse health and safety consequences to the general public.[61]

In general, it appears that LDCs have considerable discretion to develop their own approaches to assessing the high-consequence risks in their respective systems, and then to balance those risks with other variables, such as age, size, material, leak history, pressure, soil conditions, proximity to structures, public buildings, or business districts, in addition to permitting and coordination with municipalities. For example, in its 2020 GSEP, National Grid reports that it is now going to "shift the focus of its replacement activities to favor cast iron replacement, over non-cathodically protected steel."[62] It further

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[56] DPU 20-GSEP-03, Exhibit NG-AS-2, 19. See National Grid's prioritization method in DPU 20-GSEP-03, Exhibit NG-AS-3, "Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement," https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12832954.
[57] DPU 20-GSEP-05, Exhibit EGMA-DEM-2, 20 (contained within EGMA's Initial Filing on 10-30-20, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12834099).
[58] Dynamic Risk Assessment Systems, Inc., *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts*, commissioned by the Massachusetts Department of Public Utilities (January 29, 2020) 17, note 30, https://www.mass.gov/doc/dynamic-risk-phase-2-rev-1/download.
[59] Dynamic Risk Assessment Systems, Inc., 31.
[60] Dynamic Risk Assessment Systems, Inc., 32.
[61] Dynamic Risk Assessment Systems, Inc., B-77, note 301.
[62] DPU 20-GSEP-03, Exhibit AS-1, 5.

states that "[t]his decision in conjunction with an evaluation of the available capital delivery resources to deliver the plan has led to a gradual shift in the work away from the former Colonial Gas service area and into the more urban areas of the historic Boston Gas service area."[63] That cast iron has a leak rate five times that of unprotected steel has been a known fact in the industry for a considerable time suggesting that, prior to its 2020 GSEP, National Grid prioritized factors other than this material's high leak rate in its pipe replacement planning.

In their 2020 GSEP filings, both National Grid-Boston Gas and Eversource Gas of Massachusetts emphasize that their pipe replacement work is getting "more difficult" and "more complex" as they concentrate on pipe replacement in urban centers.[64] This reflects the fact that projects in densely populated locations are necessarily more costly, and time- and resource-intensive, often with challenging permitting and construction issues. More generally, in DPU 21-109, Eversource Gas of Massachusetts describes the gas distribution assets that it acquired from Bay State Gas Company in 2020 as in needed of extensive rehabilitation due to safety concerns:

> The former Bay State Gas distribution system is a high-risk asset with critical condition, design, and process deficiencies. These deficiencies will require sustained capital investment over the period 2021-2028 and beyond. The system will continue to exist in a high-risk state for at least the next 5 to 10 years.[65]

These references to the increasing difficulty, complexity, and expense of infrastructure replacement work suggest that at least the larger gas companies have yet to prioritize the bulk of their most difficult and costly replacement projects, a concern also raised by DRA in their January 2020 report.[66] It is noteworthy that the DPU has not instituted any program-wide metrics that incentivize or direct LDCs to focus on the infrastructure replacement projects that would bring about the greatest reduction in the most hazardous and climate-damaging leaks and the biggest increases in public health and safety.

During the 2020 GSEP proceedings for each LDC, the Conservation Law Foundation (CLF) raised a related consequence of failing to prioritize the "most difficult" replacement projects, namely that environmental justice populations[67] have been disadvantaged by current prioritization strategies. CLF presents data for each LDC and the Commonwealth as a whole, showing that environmental justice populations are disproportionately exposed to fossil gas leaks compared to the general population. This finding likely reflects the fact that environmental justice populations and dense, older infrastructure tend

[63] DPU 20-GSEP-03, Exhibit AS-1, 5.

[64] National Grid in 20-GSEP-03, Exhibit NG-AS-2, 36. Eversource in 20-GSEP-05, Exhibit EGMA-DEM-2, 20.

[65] DPU 21-109, Exhibit EGMA-WJA/JPD/JKD-2, 3. This exhibit is part of a larger filing by Eversource called "Comprehensive Safety Assessment & Implementation Plan" which was produced pursuant to the 2020 settlement agreement that allowed Eversource Gas of Massachusetts to acquire the assets of the former Bay State Gas Company. The Plan does not recommend any increases to its planned GSEP capital spending. However, it does propose an expanded safety-related capital budget for non-GSEP projects totaling $860.7 million for the period 2021 through 2028, including $247 million for LNG/LPG facilities, $130 million for gate stations and district regulators, and $196 million for system reliability programs. See DPU 21-109, Exhibit EGMA-WJA/JPD/JKD-1, Table 1, 22.

[66] Dynamic Risk Assessment Systems, Inc., *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts, commissioned by the Massachusetts Department of Public Utilities* (January 29, 2020), Section 8.2.3.3, 35, https://www.mass.gov/doc/dynamic-risk-phase-2-rev-1/download.

[67] Environmental justice populations refer to neighborhoods that meet a specific threshold for low-income residents, people of color, or households with limited proficiency in English. For Massachusetts' statutory definition, see: An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts 8, Section 56, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

to be co-located. A recent filing by Eversource Gas of Massachusetts underscores the same point when it notes that Springfield and Lawrence both fall below 60 percent of the median household income in Massachusetts and "have the 1st and 3rd largest inventories of legacy pipe (primarily cast iron), indicating an [sic] environmental justice could be improved in these communities." [68] The company says that it will be "increasing the rate of priority pipe replacement in the Springfield area each year starting in 2022 onward."[69]

CLF recommends that "pipelines which are being evaluated for repair or replacement under a GSEP be prioritized not only according to the distributed integrity management plan and leak management, but also by their location in any environmental justice populations. To do so will be the most equitable manner of implementing GSEP…."[70]

E. Repairing vs. replacing pipes

Just as pipes can be evaluated for their risk level, so too can leaks. A uniform gas leak classification and reporting system was established by M.G.L. ch.164 § 144[71] and then implemented by DPU regulation (220 CMR 114.00), effective in 2019. Leaks are categorized as Grade 1, Grade 2, or Grade 3 based on the hazard posed and are assigned a timeline for repair or monitoring. Grade 1 leaks are considered "hazardous" and are to be repaired "as immediately as possible." Grade 2 leaks are considered a "probable future hazard" and are to be repaired within twelve months from the date the leak was classified.[72] Chapter 164 also prioritizes the repair of gas leaks detected within a school zone.[73]

Grade 3 leaks are considered non-hazardous and likely to remain non-hazardous, but a subset of them is known to have serious environmental consequences. In response to the 2016 state law, An Act to Promote Energy Diversity (2016 Mass. Acts 188), the DPU created regulations establishing criteria for identifying and repairing, or eliminating, Grade 3 leaks of significant environmental impact (Grade 3 SEI leaks). SEI leaks that do not present an explosion hazard, but they emit substantial amounts of methane into the ground and atmosphere and often harm and even kill trees.[74] Those regulations took effect three years later, in March 2019, and now utilities are required to identify SEI leaks and repair them within two years, with the incentive that these repairs can be expensed to an LDC's GSEP. However, if the SEI leak is

[68] DPU 21-209, Exhibit EGMA-WJA/JPD/JKD-2, 22-23.
[69] DPU 21-109, Exhibit EGMA-WJA/JPD/JKD-2, 22.
[70] Conservation Law Foundation, Letter to DPU Secretary Mark D. Marini et al., Subject: D.P.U. 20-GSEP-04, Liberty Utilities GSEP Filing, From Attorneys Priya Gandbhir and Staci Rubin, December 20, 2020. (Note: A similar letter was filed by CLF with each LDC's 2020 GSEP docket.) The co-location of environmental justice communities and older infrastructure is reflected in leak data across the state, including leak data disaggregated by leak class or grade, and by utility.
[71] M.G.L. ch.164 § 144(e) requires gas distribution companies in their annual service quality reports to provide the location, classification date, and repair dates of each leak existing as of the date of the report.
[72] Federal pipeline safety regulations (49 CFR 192 Part 192.703c) require only "hazardous leaks" posing imminent threat to be repaired promptly, allowing non-hazardous leaks to go unrepaired. According to PHMSA guidance, a hazardous leak represents an existing or probable hazard to people or property and requires immediate action until the conditions are no longer hazardous. Gas companies are required to identify and classify leaks according to risk as part of their federally mandated Distribution Integrity Management Plans, 49 CFR Part 192 § 1005-1007.
[73] See M.G.L. ch.164 § 144(d).
[74] An Act to Promote Energy Diversity, 2016 Mass. Acts 188, Section 13. Section 13 directs the DPU to promulgate rules regarding the timeline and acceptable methods for remediation and repair of Grade 3 leaks determined to have a significant environmental impact.

located on a segment of pipe slated for replacement under GSEP, then an LDC has up to five years to address the leak. Prior to this new law and the 2019 regulations that resulted from it, LDCs had no obligation to fix this type of leak.

In its 2019 report, *Rolling the Dice,* Gas Leaks Allies finds that LDCs have wide discretion in classifying gas leaks because the terms "existing hazard" or "probable future hazard" are not sufficiently defined. Gas Leaks Allies recommends specific enhancements to the gas leaks classification and reporting system. In addition, to reduce short-term risks to safety, health, and property, it advocates for triaging gas distribution system leaks by prioritizing for repair the most hazardous and climate-damaging leaks, and not deferring them by assigning them to pipe replacement status.[75]

Leak classification and any oversight systems aside, LDCs are financially incentivized to replace rather than repair, a point underscored in a 2013 report prepared for Senator Edward Markey who has long been an advocate for addressing leaks in the nation's gas infrastructure and reducing methane emissions generally.[76] There are two parts to this incentive. First, current regulations reflect a price-regulation distortion that under-incentivizes leak repair because LDCs are allowed to pass the cost of any lost gas on to their customers.[77] In other words, leaked gas is treated as a normal cost of doing business. Examples of alternatives include setting a cap on LDC recovery for lost and unaccounted for gas (LAUF)[78] or imposing a tax on the climate cost of methane related to leakages above a threshold amount.[79] Second, LDCs have a strong financial incentive to replace rather than repair pipes. This is because utilities are subject to a cost-plus form of price regulation and are allowed to earn a rate of return on capital investment such as replacing infrastructure, but not on repair activities because these are categorized as operational expenses involving labor and other variable costs.

Traditionally, LDCs have taken the position that replacing mains and services is more efficient and cost effective than repairing leaks. However, repairs tend to be less expensive than replacing infrastructure, with unit repair costs averaging about $4,000.[80] According to the DPU's most recent annual report on gas

[75] Bob Ackley et al., *Rolling the Dice: Assessment of Gas System Safety in Massachusetts* (Boston, MA: September 13, 2019), 20, 51-54, https://drive.google.com/file/d/1nbI5m2-FUX56_uJxMltHwSatKD5MB0cw/view. Gas Leaks Allies calls for a more detailed, standardized approach to measuring, grading, and evaluating gas leaks to be used by all distribution companies in order to strengthen public safety by enabling clearer oversight and greater public understanding.
[76] US House of Representatives, Natural Resource Committee, *America Pays for Gas Leaks: Natural Gas Pipeline Leaks Cost Consumers Billions*, Report prepared for Senator Edward Markey (July 2013), https://www.clf.org/wp-content/uploads/2013/08/Markey-Gas-Leaks-Report-2.pdf.
[77] Catherine Hausman and Lucija Muehlenbachs, "Price Regulation and Environmental Externalities: Evidence from Methane Leaks," (Working Paper 22261, National Bureau of Economic Research, Cambridge, MA, May 2016), https://www.nber.org/papers/w22261.
[78] Ken Costello, *Lost and Unaccounted-for Gas: Practices of State Utility Commissions*, (Report No. 13-06, National Regulatory Research Institute, Silver Spring, MD, June 2013), https://pubs.naruc.org/pub/FA86BB52-AE3F-D8AC-B295-801BD6DC6435.
[79] Although the DPU has not created financial incentives for LDCs to lower fugitive gas leaking from their distribution systems, since 2018 the Massachusetts Department of Environmental Protection (MassDEP) has imposed increasing annual limits on LDC methane emissions, although there is an annual set-aside that LDCs can petition to use when they exceed their methane emission limit. See Section IV. C. of this report for more information.
[80] See information on National Grid-Boston Gas unit repair costs for 2018, 2019, and 2020 reported by the company in DPU 21-GREC-03, Exhibit NG-AS-4, 1. For 2020, the average unit cost (across bare steel, cast iron, and pre-1985 Aldyl-A plastic) was $3,924, fully loaded with O&M offsets. More than 60% of the leaks in the Massachusetts

leaks to the Massachusetts Legislature, in 2019, 32,252 leaks were reported in the Commonwealth's gas distribution network, including the six GSEP-participating LDCs and the four municipally-owned distribution companies.[81] Of these leaks, 16,044 went unrepaired and were carried over to the next year. This suggests a total cost of $64 million to address backlogged leaks and, then assuming 15,000 new leaks per year, an additional $60 million to repair leaks annually going forward.[82] As will be shown in Section IV**, infrastructure replacement under GSEP is now costing over $500 million per year.**

Repairing rather than replacing pipes is generally more cost-effective, but a recent study of leak repair in Massachusetts by Edwards et al. finds that LDCs need to improve their leak repair operations and monitoring, and that the Commonwealth should put in place more effective leak repair and monitoring policies.[83] The study finds a 20 percent failure rate in leak repair state-wide over the period 2014 to 2017,[84] with the largest number of failures concentrated in the Boston metropolitan area and other large cities such as Worcester, Springfield, and Lowell. In addition, the study conducted on-site gas leak measurements at 61 locations where repairs have been performed on potentially high-emitting Grade 3 leaks from 2019 to 2020 and found an effective failure rate of 75 percent. The study explains that there are several potential causes for repeat repair failures: "Utility workers may apply temporary fixes without eliminating the underlying leak. Leaks may also re-emerge along leak-prone segments of the network, or repairs may only address one of many leaks in the same vicinity."[85] The researchers urge greater policy and regulatory focus on the problem of repair failures, including creating incentives to successfully repair leaks (especially those that are high emitting but nonhazardous), and developing clear protocols to verify and monitor repairs.[86]

Pipe repair and leak monitoring technologies have been advancing rapidly. It is now possible to avoid intensive pipe replacement and instead, at much lower cost, extend the life of a leaking pipe by inserting a new pipe inside of the old pipe using sleeving methods or robotic tools to line the inside of pipes.[87] In addition, technologies exist for repairing leaking joints from the inside, for example, using cast-iron sealing robots (CISBOTs). Keyholing tools can be used to create a small hole opening in the ground to

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fossil gas system are in this territory, and, at the end of 2019, National Grid-Boston Gas accounted for 67% of the unrepaired leaks (DPU 20-GLR-01, Appendix A).

[81] DPU 20-GLR-01, Appendix A.

[82] Appendix A of DPU 20-GLR-01 provides data by LDC on "Cost to Complete" the "Backlog Repair Estimates." For 2019, the total cost to complete across all gas companies was $35,880,786, but this figure is not calculated as the cost to complete repair of the leaks pending at the end of the reporting year. Note 15 of the report states "While there were 16,044 leaks remaining on the distribution system at the end of 2019, the companies/operators have already repaired or eliminated a portion of those leaks during 2020; thus, the repair costs may reflect only part of the backlog that existed at the end of 2019."

[83] Morgan R. Edwards et al., "Repair Failures Call for New Policies to Tackle Leaky Natural Gas Distribution Systems," *Environmental Science & Technology* 55, no. 10 (May 3, 2021): 6561-6570, https://pubs.acs.org/doi/10.1021/acs.est.0c07531.

[84] Edwards, 6563. Repair failures are defined as "any unsuccessful or impermanent attempt to eliminate CH_4 emissions at a particular location" (Edwards, 6567).

[85] Edwards, 6565. See the "Qualitative Analysis" section of this study" (6561) for an important discussion of the technical, organizational, and policy challenges to leak repair.

[86] Edwards, 6567.

[87] See descriptions of advanced pipe encapsulation technology at the US Department of Energy, Advanced Research Projects Agency-Energy (ARPA-E), https://arpa-e.energy.gov/technologies/programs/repair.

perform pipeline maintenance activities instead of the traditional much larger open-cut excavation.[88] The interior of pipes can be inspected with trenchless methods of intelligent "pigging" and robotic pipe inspection using "crawlers" to search for rust, weak seams, thinning walls and other indicators that a pipe needs repair or replacement.[89] Above-ground enhanced monitoring of large sweeps of the gas system is also available using mobile platforms for leak detection equipped with cavity ringdown spectrometers. Mobile platforms could in theory monitor the entire Massachusetts gas distribution system several times a year rather than the less frequent passes now required by the DPU.[90]

As Edwards and her co-authors underscore, "[p]olicymakers can create incentives to successfully repair leaks (especially those that are high emitting but nonhazardous) and develop clear protocols to verify and monitor repairs."[91] But so far, those incentives and protocols have not been instituted in the Commonwealth; instead, each utility is chiefly responsible for developing and implementing its own repair standards. The use of state-of-the-art monitoring and repair technologies by LDCs is hindered by the fact that the regulatory cost recovery system rewards pipe replacement, not pipe repair, and pipe replacement is at the core of the profitability of the current gas utility business model. GSEP continues this bias toward replacement with the one exception described at the beginning of this section: SEI leak repairs are an eligible GSEP expense. However, as indicated, even the SEI repair incentive can be overridden by replacement if the repair is delayed by assigning the pipe to replacement status.

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[88] "Top 10 Keyhole Uses for Smart Construction," *Underground Construction* 69, no. 2 (February 2014), https://ucon611online.com/magazine/2014/february-2014-vol-69-no-2/features/top-10-keyhole-uses-for-smart-construction.

[89] Tabitha Mishra, "Understand the Differences Between Pigging and Robotic Pipe Inspection Methods," Trenchlesspedia (April 18, 2019), https://www.trenchlesspedia.com/understanding-the-differences-between-pigging-and-robotic-pipe-inspection-methodspipe/2/3578.

[90] Tim Keyes et al., "An enhanced procedure for urban mobile methane leak detection, *Heliyon* 6, no. 10 (October 2020), https://doi.org/10.1016/j.heliyon.2020.e04876. Independent research using precise measuring devices, such as the Picarro Cavity Ring-Down Spectrometer, typically document more gas leaks than are reported by state regulatory agencies which often rely heavily on human-reported leaks. See 220 CMR 101.06 (21) for DPU's "Massachusetts Natural Gas Pipeline Safety Code. Paragraph 21 ("Distribution Systems Leakage Surveys and Procedures") provides that business districts must be surveyed at least once every twelve months for gas leaks; all other areas must be survey at least once every 24 months.

[91] Edwards, 6567.

IV. GSEP Outcomes Through 2020

GSEP is now a quarter of the way through its extended 25-year timeline. This is, therefore, an important time to take stock of the program, especially given recent developments in the Commonwealth's climate mitigation policies and the urgent need to reduce greenhouse gas emissions. This section examines three sets of GSEP "outcomes" through 2020: (1) the amount of infrastructure replaced and the associated capital spending costs, (2) trends in replacement costs, and (3) progress in managing and reducing leaks across the six LDCs.

A. Infrastructure replaced and associated replacement costs

LDCs participating in GSEP have now carried out six successive years of infrastructure replacement. Through calendar year 2020, 1,348 miles of mains have been replaced or an average of 225 miles of main per year. In addition, just over 86,000 associated services have been replaced. This means that during the first quarter of the program's extended 25-year timeline, roughly one-fifth of the Commonwealth's leak-prone legacy infrastructure has been replaced, indicating that GSEP's overall pace of replacement is lagging the program's elapsed time.[92]

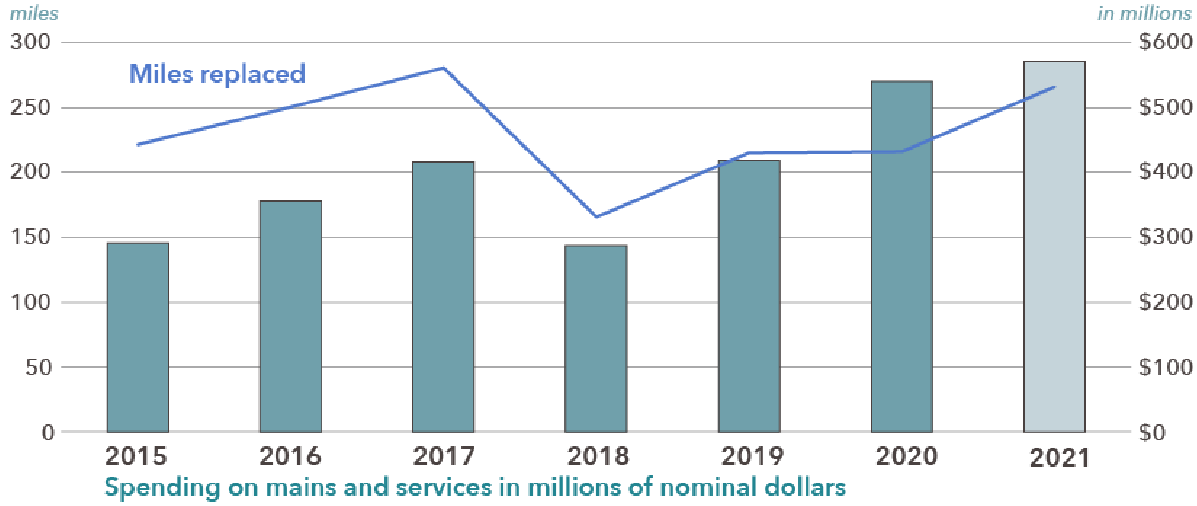
GSEP capital outlays from 2015 through 2020 totaled $2.3 billion (in nominal dollars) or $385 million per year on average.[93] In March 2021, the DPU approved LDC infrastructure plans for 2021. During this year, LDCs aim to replace 266 miles and associated services at a total projected cost of $570.4 million—the highest ever proposed annual spending for GSEP. The next highest spending level occurred in 2017 when $416.7 million was spent to replace 280 miles, 5 percent more pipeline than is forecast to be replaced in 2021. Figure 4 presents a snapshot overview of GSEP from inception through 2021 in terms of miles of distribution main replaced and capital spending for the same including services.[94]

[92] To calculate the total miles replaced by the LDCs through 2020, this report relied on LDC accounting provided in their most recent GSEP-related filings with the DPU. However, there are instances where figures on total miles and services replaced for 2020 were either not provided in an LDC's 2020 GSEP docket or were subsequently updated in related dockets, such as the Gas System Enhancement Plan Reconciliation Filing (GREC) filed as 21-GREC-01 through 06. For each LDC, the most updated figures provided were used.

[93] To calculate total spending across the six LDCs through 2020, this report relied on LDC accounting provided in the most recent GSEP-related filings with DPU. However, there are instances where the spending totals for 2020 were either not provided in an LDC's 2020 GSEP docket or were subsequently updated in related dockets such as the Gas System Enhancement Plan Reconciliation Filing (GREC) filed as 21-GREC-01 through 06. For each LDC, the most updated figures provided were used.

[94] For clarity of presentation, Figure 4 focuses on miles of main replaced. Here is the corresponding information for services replaced: The total number of services replaced increased rapidly during the first three years of GSEP from 11,119 in 2015, to 16,804 in 2016, to 18,708 in 2017. Replacement of services then fell to 11,337 in 2018. In 2019 and 2020, 13,995 and 14,087 services were replaced, respectively. A projected 15,387 services are to be replaced in 2021. See 17-GLR-01, 20-GLR-01, and 20-GREC-01 to 06.

Figure 4: Miles of pipeline replaced and associated infrastructure spending, 2015-2021 projected



Sources: 17-GLR-01 through 20-GLR-01, and 20-GREC-01 to 06.

The pace of GSEP replacement activity has unfolded differently than planned. A five-year ramp up period was expected, resulting in a replacement run rate for each LDC that, if sustained, would reach the targeted replacement goals within the approved time frame (with slightly longer timelines agreed to by the DPU for National Grid-Boston Gas and National Grid-Colonial Gas, and Eversource NSTAR). In 2018, GSEP-related gas explosions in the Merrimack Valley of Massachusetts led to reduced replacement activity across the entire GSEP program.[95] National Grid labor disputes further depressed GSEP work that year. Most recently, the COVID-19 pandemic in 2020 caused a work slowdown for some, but not all, LDCs. Another factor affecting the end goal is that additional miles of main have been classified as leak-prone, including significant mileage of plastic mains installed before 1985.[96]

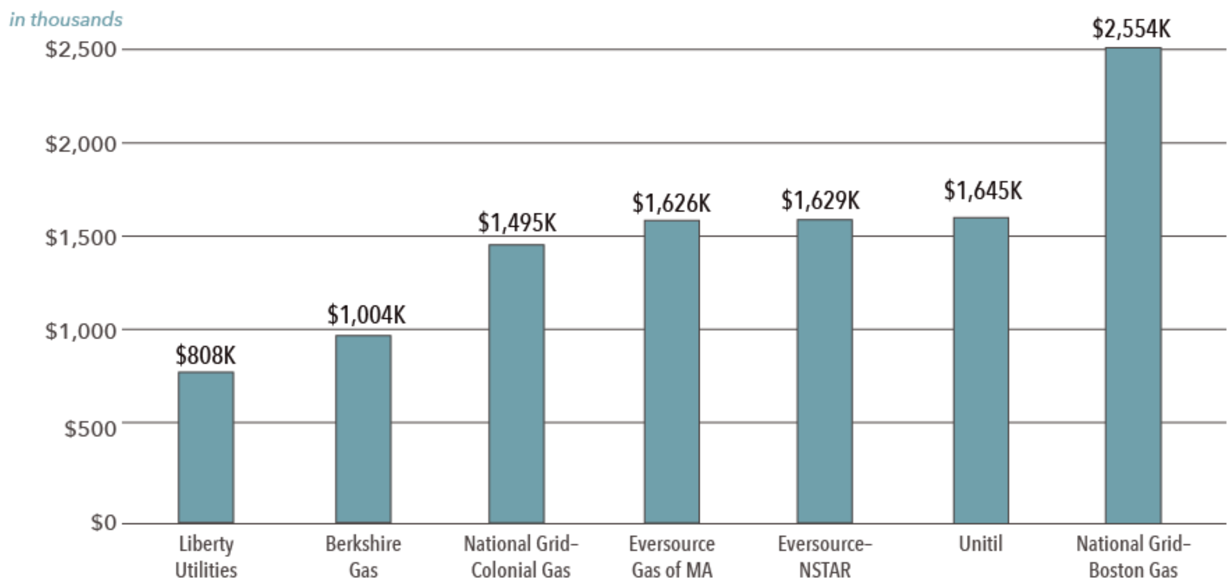
B. Trends in unit costs

The basic building block for a capital budget is the calculation of a robust unit cost that provides for the fully-loaded fixed and variable costs of producing a unit of the service or product. In the case of GSEP, the key unit of cost analysis is the cost of replacing a foot (or mile) of pipeline).[97] Figure 5 shows the unit costs used by each LDC to develop its 2021 GSEP. Liberty Utilities, serving customers in Fall River, North Attleboro, Plainville, Somerset, Swansea, and Westport (as well as the former Blackstone Gas territory), reports the lowest cost at $807,840 per mile. National Grid-Boston Gas reports the highest cost

[95] See note 103 for more information.
[96] For reclassification activity regarding plastic mains, see note 35. Additionally, copper services have been added to the leak-prone inventory of services.
[97] Some companies report unit costs for each pipe material by pipe size (e.g., 12” thermoplastic HDPE (high-density polyethylene)) while others report a unit cost averaging across different pipe materials. Additionally, Unitil declined to report unit costs in its GSEP filings saying that it builds budgets for individual street projects; however, in its 21-GREC-01 filing, the company does report “cost per unit” in DPU 21-GREC-01, Exhibit Unitil-CLTB-1, 16, Table CLTB-4.

at $2.6 million per mile—more than three times Liberty's cost. Weighted by the pipeline each company expects to replace in 2021, the average unit cost across all LDCs is $1.95 million.

Figure 5: Main replacement unit costs per mile for local distribution companies, 2021

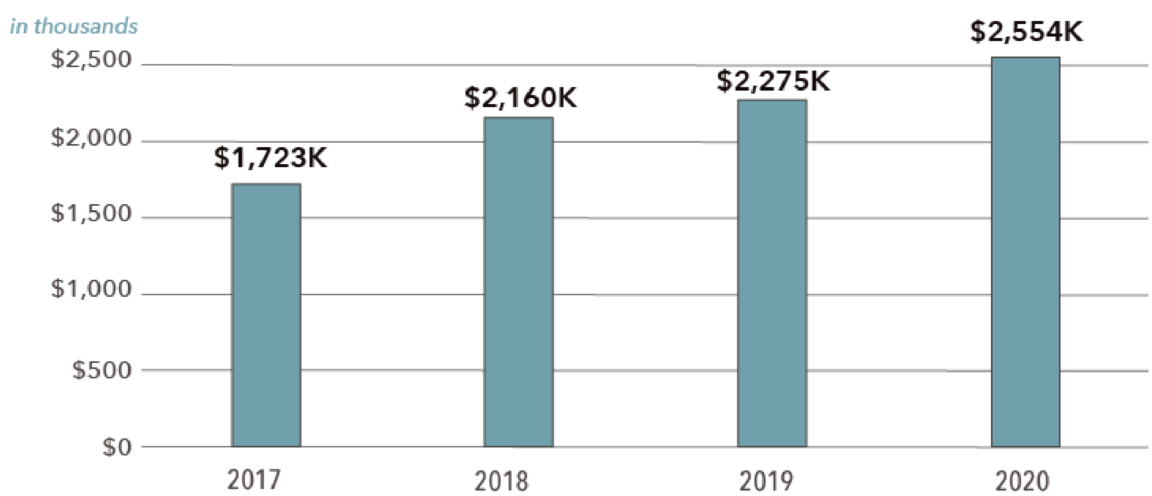


Note: Numbers for Fitchburg and National Grid are for 2020; 2021 figures were not provided.

Sources: 21-GREC-01, 03, 06 and 20-GSEP-02, 04, 05.

Another important consideration is how unit costs have been changing over time. In response to information requests by the attorney general during the 2020 GSEP proceedings for each LDC, companies provided information on time trends in their unit costs. Figures 6 to 9 show trends in unit costs for the four largest LDCs.

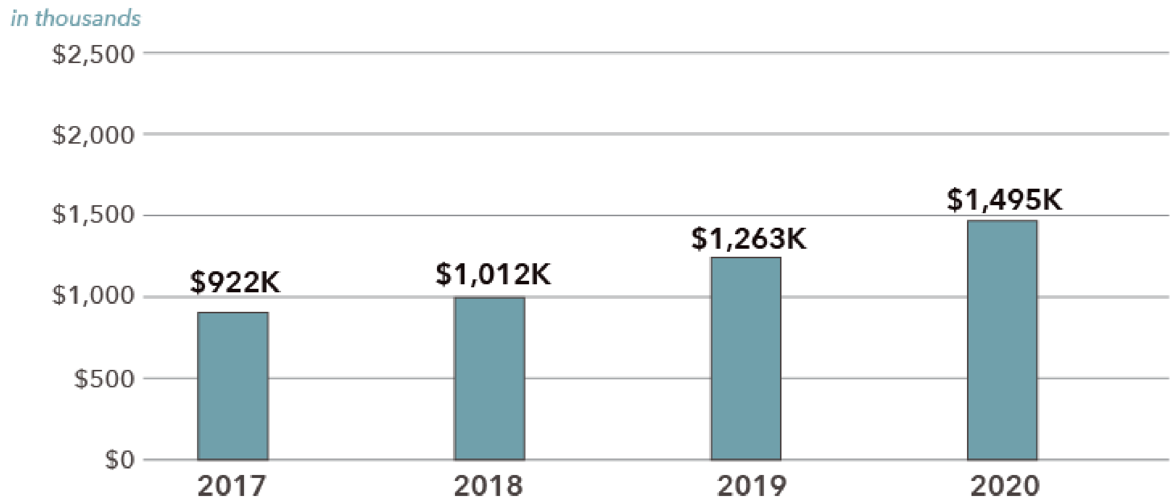
Figure 6: National Grid-Boston Gas, main replacement unit costs per mile, 2017-2019 (nominal dollars)



Source: 21-GREC-03, Exhibit NG-AS-6 and 20-GREC-03, Exhibit AG-1-24.

The territory under the Boston Gas division of National Grid has the highest replacement cost in the Commonwealth and also contains the greatest amount of leak-prone pipe. The cost of replacing one mile of pipe for National Grid-Boston Gas increased by nearly 50 percent from 2017 to 2020, from $1.7 million to $2.6 million or by an average of 16 percent per year (see Figure 6).

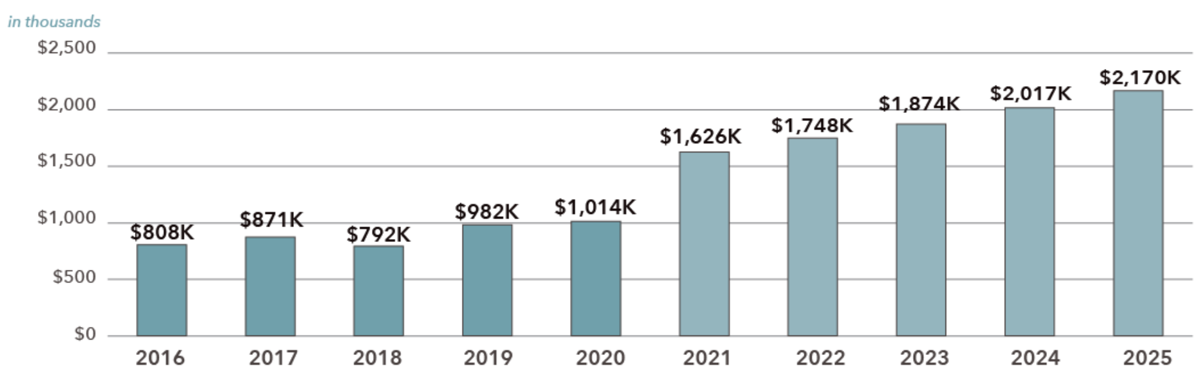
Figure 7: National Grid-Colonial Gas, main replacement unit costs per mile, 2017-2020 (nominal dollars)



Sources: 21-GREC-03, Exhibit NG-AS-6 and 20-GREC-03, Exhibit AG-1-24.

For comparison, the unit costs of the Colonial Gas Company division of National Grid have increased 62 percent over the past three years (2018-2020), or by 21 percent per year (see Figure 7).

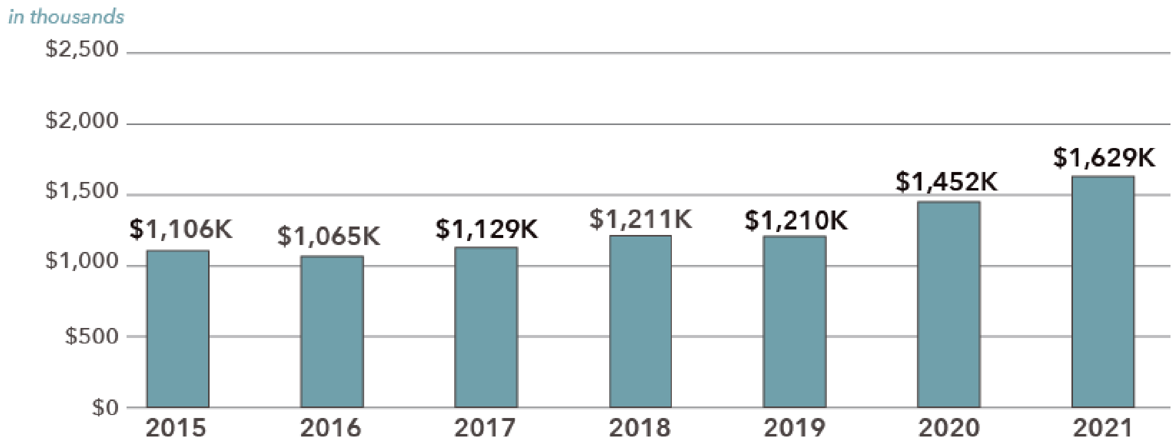
Figure 8: Eversource Gas of MA, main replacement unit costs per mile, 2016-2020 actual and 2021-2025 projected (nominal dollars)



Source: 20-GSEP-05, Exhibit AG-1-25.

Looking back at the last four years, Eversource Gas of Massachusetts, like National Grid-Boston Gas, reports rising annual unit costs in the range of 17 percent. For the period 2020 to 2021, Eversource reports that it increased its unit cost estimate by 60 percent. Furthermore, it expects its unit costs to increase at about 7.5 percent per year through 2025 (see Figure 8).

Figure 9: Eversource NSTAR, main replacement unit costs per mile, 2015-2021 (nominal dollars)



Source: 20-GSEP-06, Exhibit AG-1-19 (a) through (f).

Eversource NSTAR reports relatively steady unit costs from 2015 to 2019, but for 2020 and 2021, the company has told the DPU to expect unit cost increases of 17.5 percent per year (see Figure 9).

The GSEP filings of the larger LDCs provide insights into the factors driving up unit costs and suggest these costs will continue to increase as these companies turn their focus to the more difficult, time-consuming, and expensive replacement projects that are often located in more urban areas. Here is National Grid's description of its remaining projects:

> Moreover, infrastructure replacement activities are becoming more complex as the Company concentrates its efforts in more urban areas, such as the City of Boston. Because mains and services in these areas are typically located in densely populated business districts with heavily congested roadways that are paved from building to building with other underground utilities and structures, it takes more time and resources to schedule and undertake large infrastructure replacement projects, making the replacement and installation of new main more difficult. Consequently, LPP replacement in the City of Boston and other urban areas are generally more expensive and time intensive. Furthermore, urban areas tend to have more inside meter sets, which National Grid will attempt to relocate outside where possible, adding an additional step and complexity to infrastructure replacement projects under GSEP. Heavy vehicular and pedestrian traffic must also be considered and, in recognition of these circumstances, municipalities often impose limited work hours, which slows the rate of production. Given these factors, the Company will likely be in a position where only small segments of main in the City of Boston and other urban areas are replaced at a time, which will be more time-consuming in terms of construction and productivity.[98]

In a similar vein, Eversource Gas of Massachusetts reports the following:

> The Company anticipates that infrastructure replacement activities will become more difficult as the Company concentrates its efforts on the urban centers, such as Springfield and Lawrence, in its service territory. In these areas, it is unlikely that the Company will be able to plan and undertake a large number of infrastructure replacement projects as the mains and services are

[98] DPU 20-GSEP-03, Exhibit NG-AS-2, 36, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12832953.

> typically located in densely populated urban and business districts with roadways that are paved from building to building and are heavily congested with other underground utilities and structures, making installation of new main problematic. In addition, urban areas tend to have more inside services, which the Company will need to relocate as part of its GSEP, adding an additional step and complexity to infrastructure replacement projects under GSEP. Heavy vehicular and pedestrian traffic must also be accommodated. In recognition of these circumstances, municipalities often impose limited work hours, which necessarily slow the rate of production. Given these factors and obstacles, the Company will, at times, most likely be forced to undertake a smaller number of projects that will reduce the amount of priority pipe replaced at any given time.[99]

Liberty Utilities describes how the first several years of the company's GSEP served as a ramp-up period allowing it to attain the run rate necessary to meet its replacement objectives for leak-prone mains and services. It reached its planned run rate in 2017 and then has exceeded that rate in recent years. It expects lower rates of replacement work going forward because its "GSEP work is focused on more challenging areas."[100]

Leaving aside the difficulty and complexity of urban projects, in their GSEP filings with DPU, LDCs underscore two main cost accelerators:

- Constraints on contractor resources
- Increased spending to address safety concerns, and the need for greater training and staffing in line with recommendations from the Dynamic Risk Assessment report

Most LDCs use contractors (not their own employees) to carry out gas infrastructure replacement work. Because of the significant scale of this work, LDCs report competing with each other, and even regionally, for the same contractor resources and also for labor sources from which to add to their own internal workforces. Eversource Gas of Massachusetts puts it this way: "the single largest factor in completing replacement projects is expected to be contractor availability and cost."[101] Similarly, Liberty Utilities states that "the single largest cost factor in completing replacement projects is expected to be contractor cost" because the company is competing "with other Massachusetts LDCs for the same labor sources for its internal workforce and for contractor resources."[102]

The Merrimack Valley gas explosions in September 2018 occurred as a result of errors made during GSEP infrastructure replacement work.[103] In the wake of those explosions, federal and state regulators

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[99] DPU 20-GSEP-05, Exhibit EGMA-DEM-2, 20-21.
[100] DPU 20-GSEP-04, Exhibit LU-NJS-NMW-2, 9.
[101] DPU 20-GSEP-05, Exhibit EGMA-DEM-2, 22.
[102] DPU 20-GSEP-04, Exhibit LU-NJS-NMW-2, 9.
[103] Wikipedia, s.v. "Merrimack Valley gas explosions," last modified June 3, 2021, 20:10, https://en.wikipedia.org/wiki/Merrimack_Valley_gas_explosions. On September 13, 2018, excessive pressure in gas lines owned by Columbia Gas of Massachusetts caused a series of explosions and fires to occur in as many as 40 homes, with more than 80 individual fires, concentrated in the towns of Lawrence, Andover, and North Andover. One person was killed and 30,000 were forced to evacuate their homes immediately. Restoration of gas service required 48 miles of mains to be replaced. Multiple class action lawsuits were filed for negligence and destruction of property; these were eventually settled by Columbia Gas for $143 million in July 2019. In February 2020, Columbia Gas pled guilty to violating federal pipeline safety laws, and under an agreement with the US Attorney's Office agreed to sell its gas distribution operations in the Commonwealth and pay a fine of $53 million. Columbia Gas was sentenced on June 23, 2020 and ordered to pay the fine as well as serve a three-year probation. See also: Gregory Korte, "Senators: Natural Gas Pressure Was 12 Times normal Level before Massachusetts Explosions," USA

and the gas industry itself have focused greater attention on LDC compliance and safety protocols and procedures, including the quality of communication between management and contracted labor. Governor Baker ordered an independent investigation by Dynamic Risk Assessment Systems, Inc. (DRA). Issued in January 2020, this report evaluates the physical integrity and safety of the Commonwealth's gas distribution systems operated by investor-owned gas distribution companies and municipal gas companies as well as the operations and maintenance policies of these companies and their actual practices. The DRA investigation found numerous safety issues, including unsafe and variable excavation practices, lack of inspections, poor process hazard analysis, insufficient focus on risk in integrated management plans, and poor learning cultures within companies. DRA also found that the DPU was insufficiently focused on pipeline safety. The report put forth 37 recommendations relating to safety and other improvements for the gas distribution systems in Massachusetts overall and laid out a series of best practices for gas companies.

In addition to the DRA report, a 2019 report by the Gas Leaks Allies reported widespread lack of redundant protocols and inspections as well as inadequate staffing, training, and protocols. The report found many layers of deficiencies:

> While the Merrimack Valley explosions are attributed to overpressurization, many small failures contributed to the problem including clerical, procedural, and structural errors. The overpressurization began with a clerical error in that a known, necessary procedure was not included in the utility operations manual and work package. The error was procedural in that there were no redundant checks in the protocol to verify pressure and catch errors. The error was structural in that an available safety feature, the automatic shutoff valve, had not been installed in pipes in these communities.[104]

In response to increased scrutiny of their operations and deep concerns about safety, LDCs have undertaken significant new spending on safety, training, and employment of more personnel. For example, in its current rate case before the DPU, National Grid-Boston Gas presented plans to hire 209 new full-time employees, 39 of whom would be assigned to meet new PHMSA requirements and to implement the recommendations of the DRA investigation, with the balance to be allocated to staffing field operations, including creating capacity to implement enhanced safety and compliance protocols and procedures.[105]

C. Leak reduction and methane emissions

One of GSEP's key statutory intents is to reduce the number of gas leaks, and thereby reduce the volume of lost and unaccounted for gas (LAUF) emitted by the Commonwealth's gas distribution system. It is striking, therefore, that a rigorous framework of statewide metrics for measuring, tracking, and evaluating progress toward reducing gas leaks and LAUF is not in place. It may be that stronger DPU regulation will be forthcoming due to a 2021 amendment to M.G.L. ch.164 § 145 that mandates more uniform LDC reporting about "leak rates" and requires LDCs to establish interim leak reduction targets with

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TODAY (September 19, 2018), https://www.usatoday.com/story/news/nation/2018/09/18/massachusetts-natural-gas-explosions-pressure-ed-markey-elizabeth-warren-columbia/1345591002/.

[104] Bob Ackley et al., *Rolling the Dice: Assessment of Gas System Safety in Massachusetts* (Boston, MA: September 19, 2019), 23, https://drive.google.com/file/d/1nbI5m2-FUX56_uJxMltHwSatKD5MB0cw/view.

[105] DPU 20-120, Exhibit NG-GSC-1.

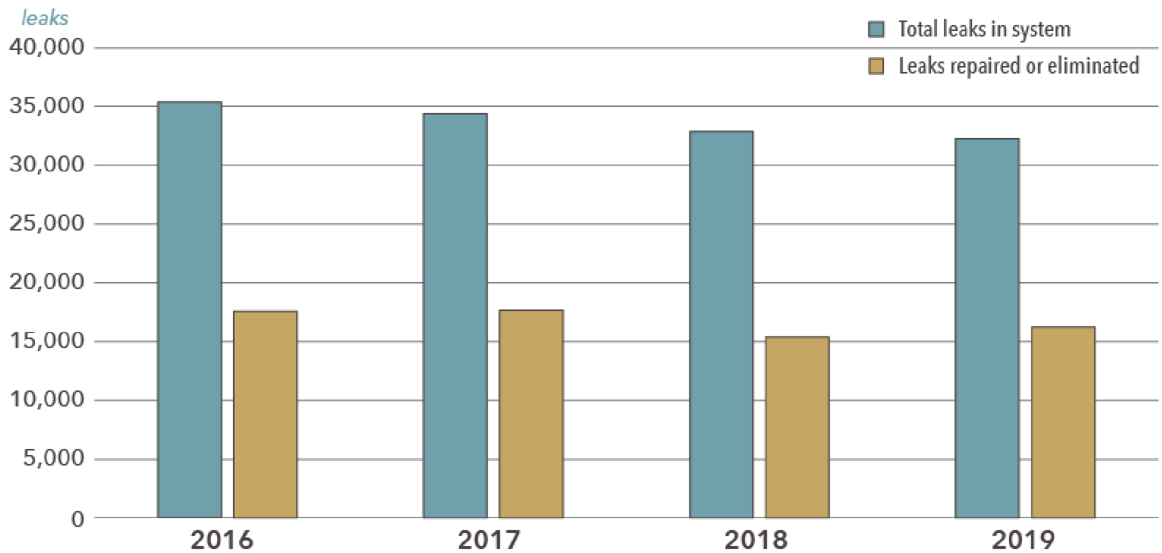
timelines.[106] This section reviews the types of LDC data currently available about leak rates from the DPU GSEP-related proceedings and about methane emissions from the MassDEP.

Using leak incidence data to assess progress in reducing leaks and LAUF

In their annual service quality report ("SQ Report") to the DPU, LDCs report: (1) the location of each Grade 1, Grade 2, and Grade 3 leak existing as of the date of the SQ Report; (2) the date each Grade 1, Grade 2, and Grade 3 leak was classified; and (3) the dates of repairs performed on each Grade 1, Grade 2, and Grade 3 leak.[107] Once a year in late December, the DPU delivers to the legislature a Gas Leaks Report, but this report is not designed to evaluate progress in leak reduction for each company.

Using the DPU's summary analysis of the leak incidence data reported in LDC SQ Reports, Figure 10 looks across all LDCs during the period 2016 to 2019 and shows total annual leaks compared to leaks repaired or eliminated.

Figure 10: Total leaks reported by local distribution companies vs. leaks repaired or eliminated, 2016-2019



Source: 20-GLR-01.

Each of the four years displays the same pattern:

- Leaks on the system total upwards of 30,000 in any given year.
- Nearly half of those 30,000 leaks are resolved through repair or replacement.

[106] An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts 8, Section 87, https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8. Section 87 amends M.G.L. ch.164 § 145 to direct LDCs to establish interim leak reduction targets and requires the DPU to review these plans to ensure that gas companies are on track to meet their leak-rate reduction targets, and to replace their aging infrastructure in a timely manner. Monetary penalties are provided, allowing the DPU to sanction an LDC for its failure to meet an interim target. The penalty amount is set at the equivalent of 2.5% of LDC transmission and distribution service revenues for the previous calendar year.

[107] LDCs are not required to report the exact location of the leaks nor their size. The latest SQ Reports can be found at DPU 21-SQ-01 through 06.

- The remaining backlog of 15,000 plus leaks is carried over into the next year whereupon new leaks emerge in roughly the same number as the number of leaks eliminated.

At this macro level, it seems clear that GSEP as a whole shows minimal progress in either reducing the overall number of leaks in the system or increasing the number of leaks repaired or eliminated.

During the DPU's GSEP-related proceedings, LDCs report leak ratio measures (e.g., leaks per 100 miles of main by pipe material or for all materials), often in response to information requests by the attorney general. While the DPU has not instituted standardized leak ratio reporting criteria, the DRA report strongly recommended using leak ratios to measure the progress of LDCs in successfully replacing infrastructure. According to DRA, a "high-level analysis of leak ratios can help determine if renewal is staying ahead of overall system deterioration."[108] Table 3 gives a four-year retrospective of the number of new leaks per year per 100 miles of main for each LDC, using statistics reported by the DPU in its latest report on gas leaks to the legislature. For the LDCs with the smallest territories (columns highlighted in orange), declining trends in leak ratios are suggested whereas for the larger LDCs (National Grid and the two Eversource companies), no clear trends are apparent.[109]

Table 3: Leak ratios for local distribution companies, 2016-2019 (new leaks per 100 miles of main)

	Until	Berkshire Gas	National Grid	Liberty Utilities	Eversource Gas of MA	Eversource NSTAR
2016	129	62	76	76	90	34
2017	93	39	85	63	76	66
2018	84	35	85	55	85	41
2019	76	20	75	52	75	46
No. of customers	16,256	40,000	930,168	56,575	323,000	300,000

Source: Calculated from data reported in DPU 20-GLR-01.

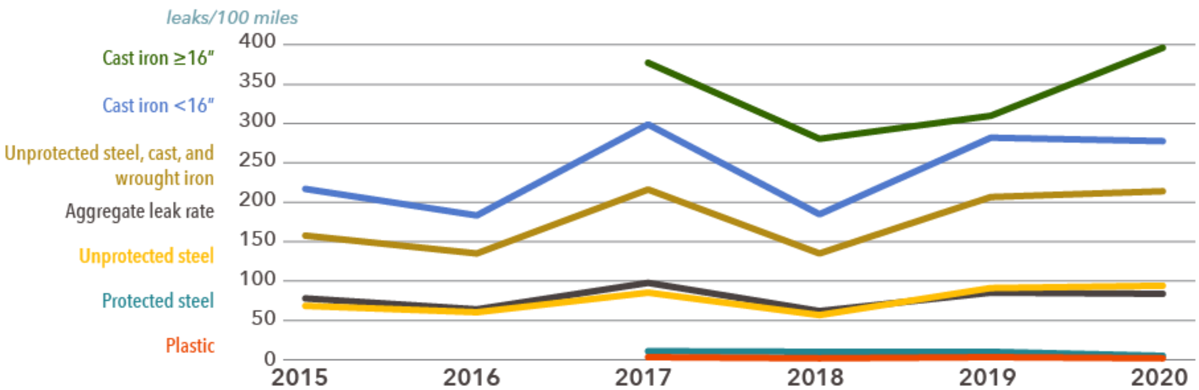
Using information reported in the recently concluded 2020 GSEP proceedings, Figures 11 and 12 look more closely at leak ratios for the two companies with the highest aggregate leak ratios: National Grid-Boston Gas and Eversource Gas of Massachusetts. Figure 11 shows leaks over time by pipe material for National Grid-Boston Gas (this company accounts for two-thirds of all leaks among GSEP-participating

[108] Dynamic Risk Assessment Systems, Inc., *Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts*, commissioned by the Massachusetts Department of Public Utilities (January 29, 2020), B-78, https://www.mass.gov/doc/dynamic-risk-phase-2-rev-1/download.

[109] Eversource Gas of Massachusetts stands out for establishing leak ratio metrics and goals for its operations as part of its PBR plan. As part of its most recent GSEP plan, it submitted testimony describing these goals: "The Company has structured its GSEP to achieve a level of replacements to reduce the Aggregate Leak Rate from 0.21 leaks/mile in 2019 to a leak rate in line with the performance of plastic and cathodically protected steel mains currently quantified at 0.034 leaks/mile. A reduction in Aggregate Leak Rates to these levels will represent a substantial improvement in public safety and the reliability of service and will put the Company well below the national average." DPU 20-GSEP-06, Exhibit ES-RJB-1, 26. See also: DPU 21-SQ-06, Appendix 10, 84-85.

LDCs).[110] In 2020, after six years of GSEP infrastructure replacement work, the company's cast/wrought iron pipes and unprotected steel mains were both leaking at a higher rate than they had been in 2015. In 2020, the leak rate ranged from 94 leaks per 100 miles for unprotected steel up to 396 leaks for cast iron mains. In comparison, the aggregate leak rate was 84 (calculated as a weighted average), showing the importance of examining leak rates by pipe material.

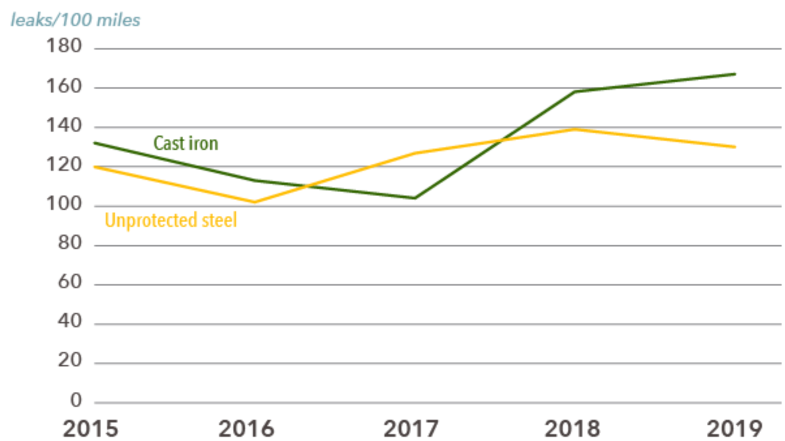
Figure 11: National Grid-Boston Gas, leaks per 100 miles of main by pipe material, 2015-2020



Source: DPU 21-GREC-03, Exhibit NG-AS-6 and DPU 20-GREC-03, Exhibit NG-AS-6.

Figure 12 shows leak rate trends for two main categories of leak-prone pipe for Eversource Gas Company of Massachusetts. The company provided a detailed analysis of these leak trends, calling some of the increased leakage per mile "significant" while asserting that its "GSEP is keeping pace with the rate of system deterioration."[111]

Figure 12: Eversource Gas of MA, leaks per 100 miles of main by pipe material, 2015-2019



Source: DPU 20-GSEP-05, Exhibit EGMA-DEM-2, 35.

[110] DPU 20-GREC-03, Exhibit NG-AS-6, and DPU 21-GREC-03 Exhibit NG-AS-6.
[111] DPU 20-GSEP-05, Exhibit EGMA-DEM-2, 34-39.

In sum, a case could be made that ratepayers in the smaller LDC territories—Unitil, Berkshire Gas, and Liberty Utilities—are receiving a positive return on their GSEP investment in the form of measurably reduced leak ratios.[112] With regard to the larger LDCs—National Grid and the two Eversource companies—no downward trends in the aggregate leak ratios of these companies is apparent and the pipe-specific leak rate data for National Grid-Boston Gas show concerning increases in leak rates for each leak-prone pipe material.

While monitoring leak rates over time may be useful, one critically important reason for *not* relying exclusively on leak ratio metrics for gauging LDC leak reduction progress is that a small fraction of larger leaks drives methane emissions from the Commonwealth's gas distribution system. Reporting on a survey of methane emissions from 100 gas leaks in cast iron distribution mains in Metro Boston, Hendrick et al. found that seven superemitter leaks (7 percent of the leaks) contributed 50% of all fugitive methane emissions measured.[113] Fifteen of the leaks were deemed likely Grade 1 leaks (using PHMSA criteria). The study authors underscore that this skewed distribution of leak size has significant policy implications. First, to stem greenhouse gas emissions, superemitter leaks must be fixed even if they don't present a hazard to life and property, and second, small leaks cannot be disregarded as safely leaking and therefore also need to be addressed. Rather than a simple, one-dimensional leak-ratio metric (which implicitly assumes a normal distribution for leak size), the researchers propose "a two-part leak classification system that reflects both the safety and climatic impacts of natural gas leaks."[114]

Using trends in methane emissions to assess progress in reducing leaks and LAUF

A second avenue for evaluating the impact of GSEP on leak reduction is progress reducing reported methane emissions. Unfortunately, this is an area fraught with metrics issues and confusing jurisdictional assignment. LDCs routinely report methane emission reductions related to their infrastructure replacement work. These estimates are derived by multiplying the number of miles of replaced pipeline by standardized national emission factors, resulting in a measure of metric tons of methane removed per year. LDCs report these estimates of their methane emissions annually to the Massachusetts Department of Environmental Protection (MassDEP) under 310 CMR 7.73.[115] They also provide an accounting of their lost and unaccounted for gas (LAUF) to the DPU under 220 CMR 115 ("Uniform Reporting of Lost and Unaccounted-for Gas").[116]

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[112] It should be noted, however, that the absolute level of Unitil and Liberty's leak rates is still high compared to the national average.

[113] Margaret H. Hendrick et al., "Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments," *Environmental Pollution* 213 (June 2016): 710-716.

[114] Margaret H. Hendrick et al., "Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments," *Environmental Pollution* 213 (June 2016): 715.

[115] Massachusetts Department of Environmental Protection, *Reducing Methane Emissions (CH4) from Natural Gas Distribution Mains & Services (310 CMR 7.73)*, https://www.mass.gov/service-details/reducing-methane-CH4-emissions-from-natural-gas-distribution-mains-services-310-cmr-773. Consistent with the Global Warming Solutions Act (2008 Mass. Acts 298) and An Act Relative to Green Communities (2008 Mass. Acts 169), this regulation contains mass-based, annually declining aggregate limits on methane emissions from main and service lines owned by gas operators with GSEPs. This emissions reduction regulation is one of several climate policy strategies outlined in the Interim Massachusetts Clean Energy and Climate Plan for 2030, https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020.

[116] An Act to Advance Clean Energy, 2018 Mass. Acts 227, Section 19. This act required the DPU to promulgate regulations requiring gas companies to report lost and unaccounted for (LAUF) gas in a uniform manner. In 2019, the emissions factors for LAUF reporting appear to have changed so that the methane emissions reported in 20-GLR-01 are not comparable with prior year reporting.

For the amount of CH_4 emitted per leak (except for copper services), both the MassDEP and the US Environmental Protection Agency use emission factors reported in a 2015 "bottom-up" study by Lamb et al.[117] Bottom-up studies develop average emission factors from direct emission measurements at the component or facility level and then multiply these factors by a source category (e.g., pipeline leaks measured as CH_4 emitted per mile for each pipe material, or CH_4 emitted per leak). For several years now, experts and advocates have argued that the emission factors in the Lamb study are outdated and that MassDEP should base its emission factors on scientific evidence from more recent studies. It has also been recommended that MassDEP utilize the actual leak data reported in LDC annual reports submitted to the DPU rather than relying on national average leak data. For example, in recent comments submitted to MassDEP about reducing methane emissions, the environmental nonprofit HEET writes:

> Given that the miles of leakprone pipe in the state have decreased annually, but the number of gas leaks reported by the utility has not, reporting a GHG [greenhouse gas] reduction based on miles of leakprone pipe is not accurate. This false reduction in GHG reporting has the potential to have serious implications for our state's net-zero planning process.[118]

"Top-down" emissions estimates are based on atmospheric sampling of methane concentrations at the regional scale. These studies complement the methodology of "bottom-up" studies and provide further evidence that the method the Commonwealth currently uses to estimate methane emissions accounts for only a fraction of actual leaked fossil gas. For example, using data collected from an advanced mobile leak detection (AMLD) platform, a recent study by Weller, Hamburg and von Fischer (2020) reports a national methane emissions estimate that is approximately five times greater than the US Environmental Protection Agency's current greenhouse gas inventory estimate for pipeline mains in local distribution systems.[119]

Another top-down study quantifying methane emissions with particular importance for Massachusetts was conducted by McKain et al.[120] That study used a comprehensive atmospheric measurement and modeling framework to measure losses from fossil gas transmission, storage, distribution, end use, and LNG importation in the Boston urban region during 2012-2013. The investigators found emission rates approximately six times greater than the current MassDEP bottom-up loss rate. Recently, the McKain

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[117] Brian K. Lamb et al., "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," *Environmental Science & Technology* 49, no. 8 (March 31, 2015): 5161–5169, https://pubs.acs.org/doi/abs/10.1021/es505116p.The difference in MassDEP and EPA's emission factors arises from the use of different leaks per mile values. MassDEP uses the leaks per mile values from the 2015 Lamb study, while EPA continues to use the leaks per mile values from a joint study by the EPA and the Gas Research Institute published in 1996. Massachusetts Department of Environmental Protection, *Program Review Report and Technical Support Document on Proposed Amendments to 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services* (December 2020): 12-13, https://www.mass.gov/doc/310-cmr-773-technical-support-document-tsd/download.

[118] HEET, "Comments on Regulation 310 CMR 7.73 Reducing Methane Emissions," Letter submitted to Massachusetts Department of Environmental Protection (January 29, 2021), https://heet.org/wp-content/uploads/2021/08/Comments-on-Mass-DEP-310-CMR-7.73.pdf.

[119] Zachary D. Weller et al., "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," *Environmental Science & Technology* 54, no. 14 (June 10, 2020): 8958–8967, https://pubs.acs.org/doi/10.1021/acs.est.0c00437. The authors attribute the much higher methane estimate to both a larger estimated number of leaks and better characterization of the upper tail of the skewed distribution of emission rates.

[120] Kathryn McKain et al., "Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts," *Proceedings of the National Academy of Sciences* 112, no. 7 (2015): 1941-1946, https://doi.org/10.1073/pnas.1416261112.

study was extended to cover the period 2012 to 2019, using updated models and meteorological products. The loss rate for this longer period remains about six times higher than the reported MassDEP loss rate. The study authors note that, while Massachusetts reports a 14 percent reduction in fossil gas emissions over the last six years, they find no such statistical trend in losses for the period 2013 to 2019.[121]

As part of the Commonwealth's campaign to meet the greenhouse gas emissions mandates established by the Global Warming Solutions Act, MassDEP set out a regulation (310 CMR 7.73) to address methane leakage from the Commonwealth's fossil gas distribution system, specifically, the estimated volume of methane leaked from distribution mains and services under the control of LDCs participating in GSEP. The regulation imposes annually declining emission limits on each LDC, commencing with the three-year period that began in 2018. In March 2021, the regulation was extended to the period 2021 to 2024 following a review of the program by MassDEP in December 2020. The review concluded that "the existing declining emission limits in 310 CMR 7.73 have been effective over the last three years at providing a back-stop cap to the DPU GSEP orders and reducing CH_4 emissions from the affected gas operators."[122]

While the MassDEP methane reduction program may very well exert backstop pressure on LDC methane emissions, it is also the case that, in 2018 and 2019, total LDC methane emissions (as measured by the MassDEP) exceeded the established maximum aggregate annual targets by 1,345 and 2,763 metric tons of $C0_2e$, respectively.[123] In 2020, National Grid, Eversource NSTAR, and Eversource Gas of Massachusetts exceeded their maximum allowable methane emissions limits by a combined total of 7,408 metric tons of CO_2e.[124] Compliance in all three years was achieved by a petition process in which gas companies exceeding their methane limits can obtain set-aside emissions by petitioning MassDEP. The draw-down of set-aside emissions has increased in each of the last three years and totaled more than 5,000 metric tons of CO_2e in 2020.[125] If an LDC exceeds its emissions limit and its set-aside petition is denied, it then faces an administrative penalty.

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[121] Maryann Sargent et al., "A 7-yr Top-Down Analysis of Methane Emissions from Natural Gas Infrastructure in the Boston Urban Region" (presentation to the 100th American Meteorological Society Annual Meeting, Boston, MA, January 2020), https://ams.confex.com/ams/2020Annual/videogateway.cgi/id/518226?recordingid=518226.

[122] Massachusetts Department of Environmental Protection, *Program Review Report and Technical Support Document on Proposed Amendments to 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services* (December 2020), 4, https://www.mass.gov/doc/310-cmr-773-technical-support-document-tsd/download.

[123] Massachusetts Department of Environmental Protection, "310 CMR 7.73 Program Review: Reducing Methane Emissions from Natural Gas Mains and Services," (slide presentation, September 10, 2020), 4, https://www.mass.gov/doc/presentation-310-cmr-773-program-overview/download.

[124] Calculations based on MassDEP 2020 310 CMR 7.73 Annual Reporting Spreadsheet spreadsheets for each GSEP LDC provided to the author by the MassDEP.

[125] Massachusetts Department of Environmental Protection, "310 CMR 7.73 Program Review: Reducing Methane Emissions from Natural Gas Mains and Services," (slide presentation, September 10, 2020), 4, https://www.mass.gov/doc/presentation-310-cmr-773-program-overview/download. The need to access the set-aside may reflect "excessive emissions," but the set-aside may also be accessed for greater than expected distribution growth, changes in construction plans, weather events that impede replacement activity, and reclassifications of pipe material, among other things. For additional information, see: Massachusetts Department of Environmental Protection, *Program Review Report and Technical Support Document on Proposed Amendments to 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services* (December 2020), https://www.mass.gov/doc/310-cmr-773-technical-support-document-tsd/download.

The latest set of MassDEP maximum emissions allowances—if not reduced by the set-aside—requires LDCs to decrease their methane emissions by about 17 percent by 2024 from 2020 levels. Interestingly, the new limits require National Grid to reduce its emissions by 13 percent from 2020 to 2024 while the other companies are required to achieve reductions ranging from 24 to 29 percent.[126] For the years 2021 to 2024, total annual set-asides established by MassDEP (ranging between 36,000 and 38,000 metric tons of CO_2e) are equal to roughly a quarter of the aggregate quantity of LDC methane emission limits permissible in each year.[127]

In conclusion, the evidence reviewed suggests that there are improvements that MassDEP could make to the Commonwealth's methane emissions factors so that they more accurately represent actual amounts of the subset of methane released from leaks in the fossil gas distribution systems under LDC control. Additionally, although MassDEP's maximum emissions limits arguably constitute a low bar, the largest LDCs appear to be having difficulty meeting the declining methane emissions targets despite the considerable investments they have made to replace LDC distribution mains and services.

A concerning issue was reported by MassDEP, pursuant to its December 2020 review of its GSEP methane emissions reduction program. It is that National Grid and Unitil advised MassDEP as part of its 2020 program review that "they might have miles of pipeline that would need to be reclassified" from cathodically- to non-cathodically-protected steel (1,600 miles for National Grid and 6.86 miles for Unitil).[128] To accommodate this reclassification, MassDEP accordingly has increased the size of the emissions set-aside. The impact that such a substantial reclassification for National Grid would have on the company's GSEP is unknown, but were the pipe to be reclassified, it could raise National Grid's leak-prone pipe inventory by as much as 50 percent.[129] The reclassification and its significance are not addressed in the DPU's latest two GSEP-approval orders for National Grid (DPU 19-GSEP-03 and DPU 20-GSEP-03).

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[126] Massachusetts Department of Environmental Protection, *310 CMR 7.00: Air Pollution Control, Current Regulations*, Section 7.73, Tables 1-8, https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.
[127] Massachusetts Department of Environmental Protection, *310 CMR 7.00: Air Pollution Control, Current Regulations*, calculated from Tables 7 and 8, https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download.
[128] Massachusetts Department of Environmental Protection, *Program Review Report and Technical Support Document on Proposed Amendments to 310 CMR 7.73 Reducing Methane Emissions from Natural Gas Distribution Mains and Services* (December 2020), 7 and 11, https://www.mass.gov/doc/310-cmr-773-technical-support-document-tsd/download.
[129] As of 2020, National Grid's inventory of leak-prone pipe—without any reclassification—consists of approximately 3,250 miles of distribution mains. This figure is calculated from National Grid's 2020 Annual Report to the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and consists of the sum of miles of cast/wrought iron and unprotected steel. To this figure, the author of this report has added an additional 380 miles of Aldyl-A plastic pipe that is not separately broken out in the PHMSA reporting form. The PHMSA data can be downloaded from "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," Pipeline and Hazardous Materials Safety Administration, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

V. GSEP Looking Forward

Over the remainder of GSEP's extended time frame, currently sent to conclude no later than 2039, LDCs participating in GSEP are planning to replace the remaining 80 percent of their leak-prone infrastructure or more than 5,300 miles of pipe and related services.[130] What can be reasonably expected about the program's future costs and its implications for ratepayers? And to what extent is GSEP aligned with and supportive of the Commonwealth's climate policy goals and stated intention to move decisively towards a low-carbon economy?

A. Projecting GSEP total costs

Given the complexity and scale of GSEP and the considerable capital spending and increased rate-payer tariffs it requires, it is both surprising and concerning that the DPU—the regulatory agency with direct purview over the program—does not provide comprehensive, evaluative public reporting regarding GSEP as a whole, including its future course and financial viability. To fill that void, independent researchers have studied the program's capital structure to project its future costs. This section reviews two such projections—both released in December 2020—and presents this report's own cost projection.

In its report called *Fixing Massachusetts Leaky Pipes: When Will It Be Paid Off?*, the **Applied Economics Clinic (AEC)** estimates that replacing Massachusetts' leak-prone gas system will cost $15.5 to $16.6 billion (in 2019 dollars). This assumes that replacement work is completed by 2034 and costs continue to be recovered until 2050, when all assets created by the program would be fully depreciated.[131] AEC estimates that a GSEP rate base totaling $2.8-$3.0 billion across the six investor-owned LDCs had been accumulated through 2019, and that LDCs had only recovered $657 million of that amount through higher tariffs paid by ratepayers. Assuming no decline in the number of gas customers, AEC calculates that it would take more than ninety years to pay off GSEP using the $5 per month "GSEP charge" paid by customers as of 2020.[132]

The AEC analysis assumes a 15-year depreciation period, an average rate of return to LDCs of 9.06 percent, and an annual inflation factor of 2 percent. AEC used the average cost for each LDC of replacing infrastructure in 2019 (total spending divided by number of miles/services replaced). Those average costs

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[130] There is no public reporting by the DPU that provides a consistent running inventory of the amount of remaining infrastructure to be replaced. The closest accounting is the DPU's report to the Massachusetts Legislature in late December of each year called *Report to the Legislature on the Prevalence of Natural Gas Leaks in the Natural Gas System* (20-GLR-01), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13083938. But this report does not provide tables identifying the rolling inventory of GSEP-eligible leak-prone infrastructure by material or the numbers of miles and services replaced. The main purpose of the GLR report is to provide information about the status of leaks across the fossil gas distribution systems of each LDC (provided in a single appendix at the end of the report). For each LDC, the report also gives a snapshot summary of leak-prone pipe, miles replaced, and miles to be replaced in the future. The only cost information provided is a retrospective summary of total capital spending by year across all LDCs since GSEP's inception in 2015.

[131] Joshua R. Castigliego et al., *Fixing Massachusetts Leaky Pipes: When Will It Be Paid Off?*, Applied Economics Clinic (Arlington, MA: December 2020), https://aeclinic.org/publicationpages/fixing-massachusetts-leaky-pipes-when-will-it-be-paid-off.

[132] Joshua R. Castigliego et al., *Fixing Massachusetts Leaky Pipes: When Will It Be Paid Off?*, Applied Economics Clinic (Arlington, MA: December 2020), 2, https://aeclinic.org/publicationpages/fixing-massachusetts-leaky-pipes-when-will-it-be-paid-off. AEC estimates that in 2020 LDCs charged customers approximately 7 cents per therm for an average of 70 therms per month for GSEP-related costs.

for main replacement ranged from $507,166 to $1,862,376. As presented in the previous section, this study finds LDC-reported unit costs for 2021 ranging from $807,840 to $2,554,350, with considerable evidence that future unit costs will accelerate more rapidly than the overall rate of inflation in the economy.

In its study called *Getting Off Gas*, the **Conservation Law Foundation** (CLF) estimates that GSEP costs are likely to total $13.4 billion.[133] CLF assumes a 36-year depreciation period, an average rate of return to equity of 9.25 percent, unit costs for pipe replacement of $1.9 million per mile, and an annual inflation factor of 2 percent. In addition, CLF adjusted for property tax expenses, deferred tax reserves, and the operations and maintenance offset (these adjustments were not included in the AEC modeling).

The most significant difference between the AEC and CLF studies is the differing assumptions made about depreciation. CLF used a more traditional depreciation time frame for pipeline assets[134] whereas AEC assumed a shorter schedule that allows most of the new GSEP assets to be fully or partially depreciated within the original twenty-year GSEP infrastructure replacement timeline and completely depreciated by 2050.

AEC's depreciation assumption appears in line with emerging expert opinion within the gas industry that LDCs need to accelerate their rate of capital-cost recovery, given the financial impact on the fossil gas industry of the Commonwealth's goals for net zero by 2050 and substantial momentum towards decarbonization.[135] For example, as part of its new rate case (DPU 20-120), National Grid's depreciation study concludes that it is no longer appropriate to use a "business-as-usual" approach to depreciation in which service lives are based largely on the company's historical experience. The author of National Grid's depreciation report presented testimony as follows:

> [A]lthough we do not know with certainty what the actual path forward will be to achieve these reductions, a plan to reduce greenhouse gas emissions to Net Zero by 2050 and no more than 85 percent below 1990 levels could certainly have a profound impact on the natural gas industry, including declines in natural gas consumption and the migration of customers to other energy sources. Any such declines in natural gas consumption or migration of customers away from natural gas service would mean that it would not be equitable to recover costs in the same manner that has been done historically. The economic lives of the Company's assets may be significantly shorter than has occurred historically and, even if much of the natural gas infrastructure remains in place by 2050, it may be providing significantly lower volumes of gas service – both because customers may leave the system and because those that remain may be using significantly less of the commodity provided by the gas system, whether the commodity used at that time is natural gas or another fuel type.[136]

[133] Conservation Law Foundation, *Getting Off Gas: Transforming Home Heating in Massachusetts* (Boston, MA: December 2020), https://www.clf.org/publication/getting-off-gas/.
[134] In the accounting world, it has been standard practice to assume that pipelines have a service life of about 55 years and that services have a life of about 35 years.
[135] Conservation Law Foundation, *Getting Off Gas: Transforming Home Heating in Massachusetts* (Boston, MA: December 2020), 20, https://www.clf.org/publication/getting-off-gas/. In its report, CLF comments on the notion of accelerated depreciation: "Our estimate is that accelerating the depreciation to accomplish [accelerated cost recovery by 2050] would only have a modest, 5-6% on residential gas rates. This occurs because the increased depreciation would be partially offset by a lower investment base (reflecting the increased depreciation) for return on capital and property taxes. In fact, the impact on consumers would likely be even smaller because the gas utilities could not prudently continue to reinvest in their infrastructure as they approach 2050."
[136] DPU 20-120, Exhibit NG-NWA-1, 24-25.

The testimony concludes:

> For these reasons, my opinion is that the risks resulting from decarbonization goals are most appropriately dealt with by incorporating the potential for shorter asset lives into depreciation today. The sooner the Department incorporates these factors, the lower the risk to future customers and the lower total cost to customers.[137]

The implications for ratepayers of faster cost recovery by LDCs are important to understand. In the short- to medium-term, accelerated depreciation will result in higher rates charged to gas consumers but in the long run, faster cost recovery will lead to lower total costs for consumers because the increased depreciation will be partially offset by a lower investment base (due to the increased depreciation) to which the return on capital and property taxes is applied. From the perspective of LDC investors, faster cost recovery will not alter their rate of return on infrastructure replacement investments, but shorter asset lives will put downward pressure on the longer-term earnings of gas companies.

This study models the future costs of GSEP using a capital revenue requirement approach similar to AEC's and assumes full depreciation of the assets created by the program by 2050–the year when the Commonwealth has mandated net-zero emissions–and a 2 percent inflation rate.[138] The model incorporates the most recent figures for LDC unit costs for main replacement (see Figure 5), the current LDC average rate of return to capital of 9.82 percent (see Table 2), and up-to-date numbers for each LDC's leak-prone pipeline inventory. The results indicate **total GSEP costs of more than $20 billion ($2019)**, a significantly higher cost than that found by AEC and CLF. Costs of this magnitude would make GSEP one of the most expensive infrastructure projects ever undertaken in the Commonwealth—one rivaling the scale of the Big Dig.

Given the substantial financial implications both for LDCs and ratepayers, there is a clear need for overall GSEP costs to be tracked, modeled, analyzed, and pro-actively managed at an aggregate level—presumably by the DPU. Important questions to be addressed: (1) Under what scenarios will it be possible for this scale of costs to be absorbed by ratepayers in a feasible time frame? (2) Will LDCs be able to recover their capital costs given the constraints of the revenue cap which limits cost recovery in any given year to at most three percent of total LDC revenue?

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[137] DPU 20-120, Exhibit NG-NWA-1, 35. National Grid's depreciation study develops several scenarios to be considered and recommends shortening the composite remaining life for gas mains from 55 years to 44 years. This shortening would require depreciation rates that recover the costs of gas mains and services expected to be retired by GSEP by 2039 for National Grid-Boston Gas and 2034 for legacy former Colonial Gas assets. According to testimony presented by the author of the National Grid depreciation study, the company proposes a smaller increase in depreciation than was recommended by National Grid's depreciation study (DPU 20-120, Exhibit NG-NWA-1, 31).

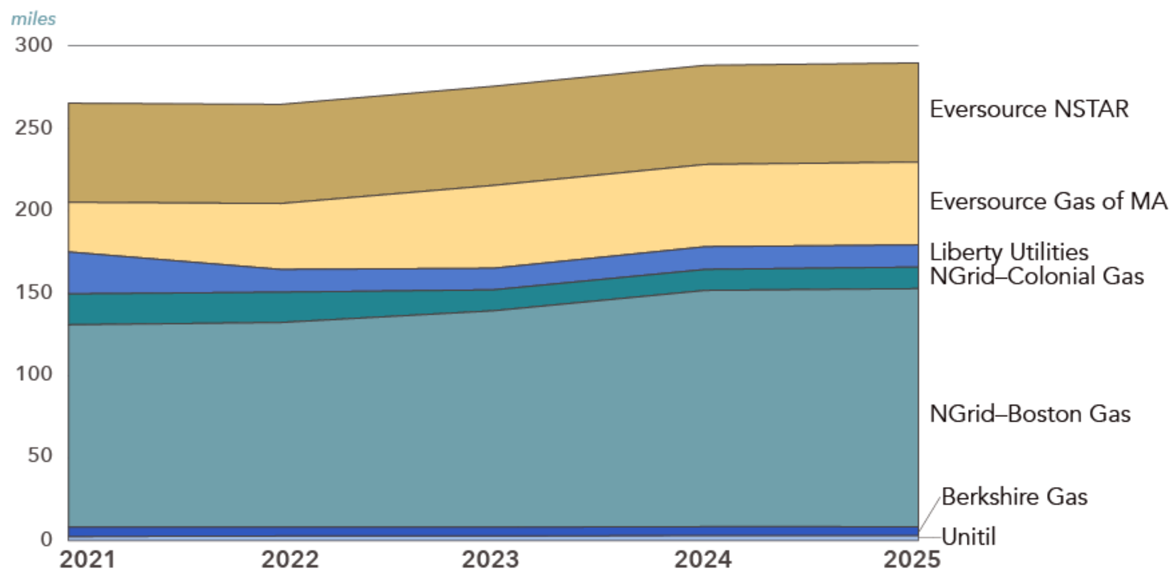
[138] Massachusetts Executive Office of Energy and Environmental Affairs, *Determination of Statewide Emissions Limit for 2050* (April 22, 2020), https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download. "Net-zero emissions" is defined by the Executive Office of Energy and Environmental Affairs as: "A level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level."

B. Prospects for meeting GSEP's extended timeline

The original GSEP timeline goal established by the legislature in 2014 was twenty years. Since that time, the DPU has granted extensions to several LDCs until as far out as 2039.[139] Even assuming the extended time frame, the rate of main pipeline replacement is lagging the elapsed timeline: a quarter of the timeframe has already passed but only twenty percent of the leak-prone pipe inventory has been replaced. This lag merits concern regarding whether the program is on track to conclude by its extended timeframe.

If GSEP's target replacement goal and time frame are to be achieved, then the collective annual replacement rate will have to accelerate considerably. Several LDCs reported setbacks to their replacement work in 2020 due to the COVID-19 pandemic and, therefore, they have pushed unfinished approved 2020 projects into 2021. In their 2020 GSEP filings, in addition to reporting on their 2020 replacement work, each LDC provided a forecast of the main replacement work it expects to accomplish over each of the next five years (see Figure 13). Taken together, LDCs expect to replace a total of 265 miles of main in 2021, increasing to 289 in 2025, for a total of **1,383 miles** replaced from 2021 to 2025.

Figure 13: Projected GSEP main replacement, 2021-2025 (miles of main per year by company)



Source: 20-GSEP-01 through 20-GSEP-06.

If an annual replacement rate of roughly 290 miles is achieved by 2025 and sustained, roughly 14 more years would be required to complete the remaining replacement work, meaning that GSEP replacement work would not conclude until 2039.[140] Note that this calculation does not include Eversource Gas of

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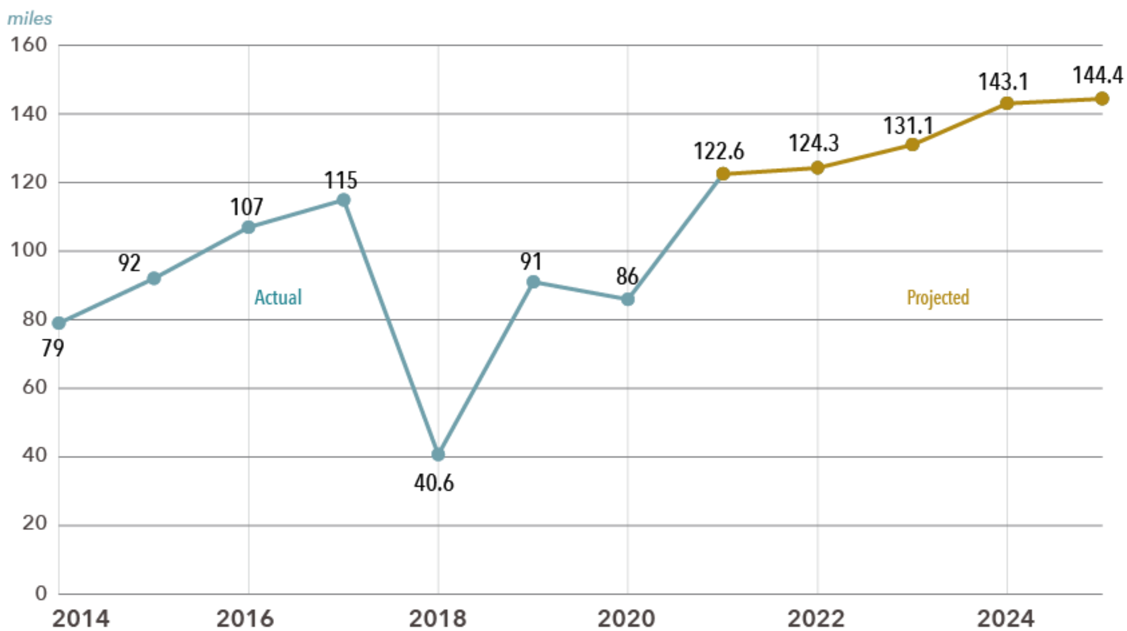
[139] See note 32.

[140] Calculations using data provided by the LDCs in their 2020 Annual Reports to PHMSA show 4,583 miles of leak-prone pipe material (non-cathodically protected steel and cast/wrought iron). To this total should be added the pre-1985 Aldyl-A pipe approved by the DPU that has not yet been replaced: 380 miles for National Grid, 356 miles for Eversource NSTAR, and 6 miles for Liberty Utilities. Adding this additional plastic pipe yields a total of **5,325 miles** of GSEP-eligible leak-prone pipe. This figure is an underestimate, however, since it does not include

Massachusetts' inventory of pre-1985 plastic pipe, which could total as much as 342 miles and add an additional six years to this company's GSEP timeline, assuming the company's proposed replacement rate for 2025.

However, the lynchpin to Massachusetts' gas system is National Grid-Boston Gas. Achieving and sustaining an overall replacement level of about 290 miles per year implies replacement levels for Boston Gas that seem unrealistic, especially given that the company reports that it has yet to undertake the most difficult and time-consuming replacement projects in its portfolio (see Section III.D). Figure 14 shows Boston Gas Company's reporting of its historical and projected main replacement, spanning the period 2014 to 2025.

Figure 14: National Grid-Boston Gas historical and projected main replacement in miles, 2014-2026



Source: DPU 20-GSEP-03, Exhibit AG-1-6.

Prior to 2021, the most miles that National Grid-Boston Gas had replaced in any year was in 2017 when 115 miles were replaced. As Figure 14 shows, over the next five years, National Grid-Boston Gas forecasts ramping up to an annual replacement rate of 144 miles. If that goal is achieved, then in that fifth year—2025—the company would be confronting a legacy infrastructure of approximately 2,582 miles of leak-prone pipe. At an annual replacement rate of 144 miles, it would take an additional 18 years—or until the year 2043—for National Grid-Boston Gas to accomplish its GSEP infrastructure replacement commitment. This end-year projection is likely conservative since it assumes that the company will not identify or reclassify any additional pipe as leak prone.[141]

Eversource Gas of Massachusetts' inventory of pre-1985 plastic pipe which could total as much as 342 miles (see note 35).

[141] See the end of Section IV. C. of this report for information about possible significant pipe reclassification by National Grid from cathodically protected to non-cathodically protected (i.e., leak prone).

C. Looming cost recovery challenges for LDCs

Analysts of fossil gas distribution systems and climate advocates across the country have been warning about the problem of stranded assets. "Stranded assets" refers to assets whose financial value declines because of the energy supply transition away from fossil fuels. The concern is that stranded assets will result as capital investments continue to be sunk into gas distribution systems that are fast becoming obsolete. This outcome seems likely given the exigencies of climate change and emerging local, state, and federal policies pushing toward a low-carbon future by mid-century.

It is no longer hypothetical to assert that the finances and operations of the Massachusetts gas industry are strongly impacted by changing market conditions associated with the transition to a low-carbon economy. This report provides evidence of significant policy changes being requested by the gas industry directly in response to the likelihood of reduced demand for fossil gas and the adverse financial implications of this reduced demand for existing LDC business models, whose profitability is closely tied to building and/or replacing more infrastructure. Specifically, this report details expert testimony from National Grid-Boston Gas in the company's current rate case calling for two important changes:

1. A higher rate of return on LDC investor equity to compensate company investors for the fact that gas industry investments are becoming increasingly risky, and

2. Accelerated capital-cost recovery through depreciation to avoid stranded assets in the face of likely declining fossil gas consumption and the migration of customers away from fossil gas service. [142]

Given the future financial challenges faced by the gas industry, both these changes may be reasonable from the LDCs' point of view, but not necessarily from a consumer equity standpoint. If the DPU agrees to these changes, a precedent will be set for the other LDCs to request similar changes in their next rate cases. These changes will result in higher gas rates for consumers[143] and add to the disadvantage of gas rates relative to electricity rates, a topic addressed in the next section of this report.

D. Gas rates soon to exceed electricity rates

Another important issue that has been studied outside of the DPU—and which arguably the DPU should be modeling internally—is the relative price change of gas to electricity as expressed in the rates paid by ratepayers. The Applied Economics Clinic (AEC)[144] and the Conservation Law Foundation (CLF)[145] have both modeled this and reach a similar conclusion, namely, that we are close to an inflection point wherein, normalized to an equivalent unit of energy, gas rates will exceed electricity rates. Both analyses

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[142] Gannett Fleming, Inc., *2019 Gas Depreciation Study: Calculated Annual Depreciation Accruals Related to Gas Plant as of December 19, 2019,* prepared for Boston Gas Company d/b/a National Grid. Presented in DPU 20-120, Exhibit NG-NWA-3, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12873229. Also see testimony in Exhibit NG-NWA-1.

[143] A higher rate of return on LDC investor equity, if approved by the DPU, will increase the company's annual revenue requirement. Accelerated capital-cost recovery will increase National Grid's depreciation by approximately $29.4 million beginning in 2020. See DPU 20-120, Exhibit NG-NWA-1 November 13, 2020, 22.

[144] Joseph R. Castigliego et al., *Inflection Point: When Heating with Gas Costs More*, prepared for HEET by Applied Economics Clinic (Arlington, MA: January 2021, updated March 2021), https://aeclinic.org/publicationpages/2021/01/13/inflection-point-when-heating-with-gas-costs-more.

[145] Conservation Law Foundation**,** *Getting Off Gas: Transforming Home Heating in Massachusetts* (Boston, MA: December 2020), https://www.clf.org/publication/getting-off-gas/.

emphasize that a key factor pushing the cost of gas higher than that of electricity is the GSEP tariff currently being applied to customer bills to allow LDCs to recover their capitalized GSEP spending.

The two studies also underscore the concern that, as more customers move away from gas to take advantage of cleaner, lower-cost energy supplies, a smaller gas customer base will be left behind to face unrecovered GSEP costs on top of the ongoing maintenance and repair costs of the gas distribution system generally. In other words, rising gas rates will have distributional consequences and the emerging cost recovery challenges of the fossil gas industry may foreshadow regressive burdens for low-income households. The CLF report describes this scenario as follows:

> [M]any of [the remaining customers] may be low-income homeowners, renters, or others unable to switch because of high upfront costs or landlords unwilling to invest in conversions that benefit renters. These remaining customers will be burdened with paying more than their fair share for a system that is increasingly expensive as well as less viable over the long term than systems using cleaner and lower-cost energy.[146]

Concern with the impending "risk of intergenerational inequity" was recently highlighted in testimony by a depreciation expert in the current National Grid-Boston Gas rate case:

> [I]f depreciation rates are too low today—and if customers electrify and leave the gas system—then the impact on future customers will be much greater because there will likely be fewer customers to pay the remaining capital costs. They will also have to pay a higher return on [the] rate base, further compounding the issue. Lastly, they will likely have to bear the costs of assets that [were] retired without being fully recovered, which is also inequitable.[147]

E. Can GSEP be aligned with state climate policy?

An in-depth examination of the 2020 GSEP proceedings of each LDC reveals no evidence of a coordinated, forward-looking inquiry by the DPU to assess whether and what changes might be needed to GSEP given the Commonwealth's evolving climate policy and aggressive climate targets that the state has been mandating for more than a decade. The first substantial climate legislation adopted in Massachusetts was *the Global Warming Solutions Act* (GWSA) of 2008.[148] which required the reduction of greenhouse gas emission levels by at least 80 percent below 1990 levels by 2050. Most recently, in March 2021 Governor Baker signed into law An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy which goes a step further to establish a statutory net-zero greenhouse gas emissions limit for Massachusetts as of 2050.[149]

During the 2020 GSEP proceedings, the Attorney General's Office asked each LDC to answer two new "climate future" questions:[150]

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[146] Conservation Law Foundation**,** *Getting Off Gas: Transforming Home Heating in Massachusetts* (Boston, MA: December 2020), 9, https://www.clf.org/publication/getting-off-gas/.
[147] DPU 20-120. Exhibit NG-NWA-1, 35.
[148] An Act Relative to Green Communities, 2008 Mass. Acts 169; An Act Establishing the Global Warming Solutions Act, 2008 Mass. Acts 298; Massachusetts Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth, September 16, 2016.
[149] An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts 8, Section 15(1A), https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.
[150] For Unitil, see DPU 20-GSEP-01 (Exhibits AG-3-6 & AG-3-7); for Berkshire Gas Co., see DPU 20-GSEP-02 (Exhibits AG-2-5 & AG-2-6); for National Grid-Boston Gas, see DPU 20-GSEP-03 (Exhibits AG-2-5 & AG-2-6);

1. Please explain whether the Company has considered other cost-effective alternatives to traditional distribution infrastructure investment that would be better aligned with the Commonwealth's 2050 climate goals, e.g., abandoning leak prone pipes for geo-thermal micro-districts, strategic electrification or other alternatives.
2. Please provide a detailed explanation of whether the Company has considered the possible future introduction of hydrogen fuel into its distribution system when selecting replacement pipe and other replacement parts of its GSEP construction work. In other words, installing pipe and material now that can accommodate the possible introduction of hydrogen fuel.

Table 5 provides a summary of LDC responses to the attorney general's questions.[151]

Table 5: LDC Responses to Attorney General's Climate Questions, 2020 GSEP proceedings

LDC Responses to AGO Climate Questions in 2020 GSEP filings	AGO QUESTION ON H2	AGO QUESTION ON FUTURE
	Is LDC considering introducing H2 into distribution system?	Is LDC considering alternatives to traditional infrastructure?
Unitil	Yes.	No, but participating in 20-80.
Berkshire Gas	[question not answered]	No, but participating in 20-80.
National Grid-Boston Gas	• Yes. "Company has considered GSEP investments in light of future H2 use and has reason to believe the pipe we are installing now is H2 ready." •"H2 is critical component of company's net zero by 2050 plan." • Company has proposed pilot demonstration for 10% blended H2 for 300 homes and a campus.	Yes, company has 4 pilot demonstration.
Liberty Utilities	Yes, GSEP pipe is conducive to H2 injection.	No, but participating in 20-80.
Eversource Gas Co. of MA	Yes, GSEP pipe is conducive to H2 injection.	No, but participating in 20-80; will evaluate NSTAR's geothermal pilot demonstration.
NSTAR Eversource	Yes, GSEP pipe is conducive to H2 injection.	Yes, company has geothermal pilot demonstration.

Sources: DPU 20-GSEP-01, Exhibits AG-3-6 & AG-3-7; DPU 20-GSEP-02, Exhibits AG-2-5 & AG-2-6; DPU 20-GSEP-03, Exhibits AG-2-5 & AG-2-6; DPU 20-GSEP-04, Exhibits AG-3-5 & AG-3-6; DPU 20-GSEP-05, Exhibits AG-2-5 & AG-2-6; DPU 20-GSEP-06, Exhibits AG-2-5 & AG-2-6.

for Liberty Utilities, see DPU 20-GSEP-04 (Exhibits AG-3-5 & AG-3-6); for Eversource Gas of Massachusetts, see DPU 20-GSEP-05 (Exhibits AG-2-5 & AG-2-6); for Eversource NSTAR, see DPU 20-GSEP-06 (Exhibits AG-2-5 & AG-2-6).

[151] The nearly identical wording of the LDCs' answers to the attorney general's questions suggests that the LDCs coordinated their responses.

Five of the six LDCs report that the pipe they are installing is "hydrogen ready."[152] This raises the prospect that LDCs may use GSEP to piggyback hydrogen into the gas distribution network, blending hydrogen with fossil gas.[153] Major research efforts sponsored by the gas industry are underway to "connect" hydrogen to the fossil gas infrastructure. For example, HyBlend[154] is a two-year, $15 million industry research and development effort to overcome the "technical barriers to blending hydrogen in natural gas pipelines." This project is receiving funding from the US Department of Energy. The gas industry considers hydrogen to be a "low-carbon fuel to substitute for natural gas."[155] However, for the foreseeable future, the vast majority of hydrogen production will depend on fossil gas to fuel its manufacture via steam methane reformation, a process that produces large quantities of CO_2.[156]

Currently, there are no industry standards for "H_2-ready" pipes and no official determination has been made by state government as to the safety and energy concentration of potential blends of fossil gas and hydrogen so that customers can burn this fuel in a safe and efficient manner with the appliances they have. The industry's high-priority research questions include: the compatibility of pipelines with hydrogen, the costs and environmental impacts, and the effect of hydrogen blends on appliances and other equipment in buildings.[157] Safety and health concerns have also been raised about using hydrogen to heat buildings and for cooking: hydrogen has a broader range of conditions under which it will ignite compared to fossil gas without a hydrogen blend component; leakage rates through plastic pipe walls for hydrogen may be higher than for fossil gas because of the small size of the hydrogen molecule;[158] and the

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[152] The principal pipe material that LDCs consider conducive to hydrogen injection is polyethylene (PE) plastic. As of the end of 2020, 52% (10,938) of the distribution mains in investor-owned LDC territories in Massachusetts consisted of this material, according to LDC gas system distribution annual reports filed with PHMSA. See zip file available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids, file name: GD AR 2020 (column CE for Massachusetts investor-own gas companies). If the remaining leak-prone pipeline main inventories were to be replaced with PE plastic, roughly 80% of the LDC gas distribution main network would consist of this "H2 ready" material (calculations by author).

[153] Richard Nemec, "Gas Industry Responds to Climate Change, Readies Transition," *Pipeline & Gas Journal* 248, no. 6 (June 2021), https://pgjonline.com/magazine/2021/june-2021-vol-248-no-6/features/gas-industry-responds-to-climate-change-readies-transition.

[154] More information is available in National Grid's December 18, 2020, press release, "Accelerating Hydrogen Blending to Decarbonize Heat," https://www.nationalgridus.com/News/2020/12/AcceleratingHydrogen-Blending-to-Decarbonize-Heat/. See also: https://www.nrel.gov/news/program/2020/hyblend-project-to-accelerate-potential-for-blending-hydrogen-in-natural-gas-pipelines.html.

[155] DPU 20-132, Exhibit AG 1-48. This information request by the attorney general provides National Grid-Boston's answer to the following question, submitted as part of the company's most recent long-range forecast and supply plan for gas for the period 2020 to 2025: "Please identify and describe all options considered or being considered by the Company to use hydrogen to meet the requirements of its customers being met by natural gas."

[156] Robert W. Howarth and Mark Z. Jacobson, "How green is blue hydrogen?" *Energy Science & Engineering* 00 (2021): 1-12, https://doi.org/10.1002/ese3.965; Sasan Saadat and Sara Gersen, *Reclaiming Hydrogen for a Renewable Future*, Earthjustice (San Francisco, CA: August 2021), https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice.pdf.

[157] National Renewable Energy Laboratory (NREL), US Department of Energy, "HyBlend Project To Accelerate Potential for Blending Hydrogen in Natural Gas Pipelines" (November 18, 2020), https://www.nrel.gov/news/program/2020/hyblend-project-to-accelerate-potential-for-blending-hydrogen-in-natural-gas-pipelines.html.

[158] M.W. Melaina, O. Antonic and M. Penev, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, National Renewable Energy Laboratory Technical Report NREL/TP-5600-51995 (March 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf.

combustion of hydrogen can produce dangerously high levels of nitrogen oxide (NOx), which is also a powerful greenhouse gas.[159]

When queried by the attorney general during the 2020 GSEP dockets about how climate change and the Commonwealth's mandated greenhouse gas emissions targets might be impacting future considerations and planning, the LDCs and the DPU responded that consideration of such questions should await the DPU 20-80 investigation.[160] DPU 20-80 is an investigation that began in October 2020 in response to a petition filed by the attorney general in June 2020 requesting that the DPU initiate an investigation to assess the future of LDC operations and planning, given the Commonwealth's 2050 net-zero goal. In its order, the DPU directed the LDCs to issue a joint request for proposals for an independent consultant to conduct a study to help the LDCs and the DPU develop a plan to guide the evolution of the Commonwealth's fossil gas industry specifically in light of the Massachusetts 2050 Decarbonization Roadmap[161] and the Massachusetts Clean Energy and Climate Plan for 2030.[162] DPU and the LDCs expect to be informed by "certain 'roadmaps' that have not yet been published by the Executive Office of Energy and Environmental Affairs."[163] Each LDC is required to submit a proposal to DPU on or before March 1, 2022, providing its recommendations and plans for helping the Commonwealth achieve its 2050 climate goals.[164]

In sum, during the 2020 GSEP proceedings, the LDCs and the DPU did not address the future of GSEP within the context of climate change and the Commonwealth's decarbonization goals. Such limitations on the scope of the GSEP-related proceedings are consistent with the narrow interpretation of the GSEP statute adopted by the DPU and the LDCs. However, the DPU and the Commonwealth's largest LDC have been delving into these very issues in the context of the most recent rate case of National Grid-Boston Gas. Testimony by company officials charged with safeguarding National Grid's financial future affirms that the state's climate goals are having a profound impact on the gas industry. Specifically, National Grid's top management is planning for the following:

- Declining gas consumption
- Attrition in the industry's ratepayer base as customers migrate to other energy sources
- Increases in the overall operating and financial risk for LDCs

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[159] California Air Resources Board, "Nitrogen Dioxide & Health," https://ww2.arb.ca.gov/resources/nitrogen-dioxide-and-health; London Energy Transformation Initiative, *Hydrogen: A decarbonisation route for heat in buildings?* (London: February 2021), https://www.leti.london/hydrogen; Lew Milford et al., *Hydrogen Hype in the Air*, Clean Energy Group (Montpelier, VT: December 14, 2020), https://www.cleanegroup.org/hydrogen-hype-in-the-air/.

[160] DPU 20-80 aside, two of the six LDCs—National Grid and Eversource NSTAR—state that they are considering "alternatives to traditional infrastructure" and have been petitioning the DPU to conduct pilot demonstrations related to introducing blended hydrogen into fossil gas pipeline networks, geothermal district energy, renewable natural gas, and a gas demand response targeting gas constrained areas. See DPU 20-GSEP-03, Exhibit AG-2-6 and DPU 20-GSEP-06, Exhibit AG-2-6.

[161] Massachusetts Executive Office of Energy and Environmental Affairs and The Cadmus Group, *Massachusetts 2050 Decarbonization Roadmap* (December 2020), https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

[162] Massachusetts Executive Office of Energy and Environmental Affairs, *Massachusetts Clean Energy and Climate Plan for 2030*, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2030.

[163] Each LDC states this expectation in its reply to the attorney general's second question referenced in Table 5. See the sources cited for Table 5.

[164] Future of Gas website, designed by Massachusetts local distribution companies as part of the Massachusetts Department of Public Utilities regulatory process in Docket 20-80, https://thefutureofgas.com/overview.

- Rising cost of operations

In response to changing market conditions and future financial prospects, National Grid company officials are recommending significant changes in how cost recovery of their rate base is conducted.

The DPU recently received expanded directives from the legislature and executive branch regarding its oversight responsibilities as they relate to climate issues. The recently enacted Next-Generation Roadmap for Massachusetts Climate Policy (2021 Mass. Acts 8) incorporates climate and equity into the DPU's enabling legislation and going forward requires the DPU to prioritize equity, security, and reductions in greenhouse gases to meet statewide greenhouse gas emission limits and sub-limits in addition to safety, reliability of service, and affordability.[165] This broadened scope creates the opportunity for the DPU to align its oversight responsibilities with the Commonwealth's mandated emissions goals, and to make changes to its gas planning processes, efficiency and electrification programs, and gas ratemaking.[166]

[165] An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, 2021 Mass. Acts 8, Section 15(1A), https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8.

[166] Recent report examining new approaches to gas utility regulation in light of state-level decarbonization policies: Megan Anderson et al., *Under 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/.

VI. Findings and Conclusions

This study reviews the first six years of GSEP to assess the outcomes achieved thus far. It also looks ahead to examine what can reasonably be projected about the future course of GSEP should it continue on its present path. The key findings of this analysis are summarized below, followed by the report's conclusions.

A. Findings

The findings of this report are grouped into six categories: costs, leak reduction and methane emissions, pipeline prioritization, GSEP timeline, GSEP financial viability, and the degree of alignment between the Commonwealth's climate policy and the DPU and GSEP.

1. Costs

a) The cost of infrastructure replacement in the Commonwealth's gas distribution system has been rising sharply, with the cost of replacing one mile of main distribution pipeline increasing on the order of 17 percent annually for the largest investor-owned gas companies. In 2020-2021, the average cost across all LDCs to replace one mile of main reached $1.95 million (weighted by LDC replacement miles).

b) Nearly 60 percent of remaining leak-prone pipe is in the National Grid-Boston Gas service territory where unit costs are highest—currently $2.56 million per mile.

c) Based on current approved rates of return and unit costs, the total cost of GSEP is likely to top $20 billion. Costs of this magnitude would make GSEP one of the most expensive infrastructure projects ever undertaken in the Commonwealth—one rivaling the scale of the Big Dig.

2. Leak reduction and methane emissions

a) While 15,000 to 18,000 leaks have been repaired or eliminated in each of the last four years, every year has begun with a backlog of unrepaired leaks roughly equal to the number of leaks repaired or eliminated during the previous year. In other words, for the Commonwealth as a whole, leak repair activity, at best, has only managed to keep up with the new leaks emerging each year.

b) Few meaningful metrics and goals have been put in place to direct LDCs to achieve targeted reductions in leaks over time. A provision of the newly enacted Next-Generation Roadmap for Massachusetts Climate Policy (2021 Mass. Acts 8) is the first requirement to set interim leak-rate reduction targets, mandating that the DPU institute more rigorous monitoring of trends in gas leak rates. The DPU has not yet issued regulations to implement this new provision but, given that a small fraction of leaks disproportionately account for the majority of methane emissions in the Commonwealth's aging gas infrastructure system, it would be problematic for the DPU to rely exclusively on one-dimensional leak ratio metrics, such as leaks per mile of pipeline. The only other instance of a metric-based, monitored outcome goal found by this study is the Massachusetts Department of Environmental Protection's program to reduce methane emissions from the gas distribution networks of GSEP-participating LDCs. So far, the results of that program show that, from 2018 to 2020, the three largest LDCs were unable to meet the declining annual maximum allowable methane emission targets established by that program.

c) To date, the Commonwealth has not created incentives to strategically and successfully repair leaks and monitor those repairs. The use of state-of-the-art monitoring and repair technologies by LDCs is hindered by the fact that the regulatory cost recovery system rewards pipe replacement, not repair, even though the life of a pipe can be significantly extended using advanced repair technologies that are more cost effective than traditional excavation and replacement.

3. Pipeline prioritization

a) The larger LDCs are only beginning to prioritize the bulk of the most difficult and expensive pipeline replacement projects where leak rates can be highest. These projects tend to be concentrated in dense, urban areas where the risk and costs involved in the replacement work are greatest and where permitting and coordination with municipalities are most cumbersome and expensive.

b) Since environmental justice communities and dense older infrastructure tend to be co-located, pipeline prioritization to date has left these environmental justice communities with leak rates per km^2 that are much higher than those found in more affluent, largely white communities.

4. GSEP timeline

a) Meeting GSEP's extended target end date—now set for 2039, just a decade before the Commonwealth's mandated 2050 net-zero emissions deadline—is increasingly unlikely. By the end of 2020, approximately 20 percent of the leak-prone pipe in the Commonwealth had been eliminated but nearly a quarter of the extended time frame had elapsed. Moreover, achieving this revised timeline assumes an infrastructure replacement rate for the largest LDC—National Grid-Boston Gas—that is both unrealistic and cost prohibitive, given the cost recovery system for GSEP and the fact that the most complicated and expensive replacement projects within the Boston Gas territory have barely commenced.

b) As infrastructure replacement costs escalate, the "revenue cap" can be expected to become a significant factor constraining LDC replacement work because it limits the increment of new annual expenses that LDCs can recover through customer rate increases (the "revenue requirement"). As LDCs max out their revenue requirement with fewer, more costly replacement miles, they will be unable to keep up with the rate of infrastructure replacement work required by GSEP's timeline unless further extensions are approved.

5. GSEP financial viability

a) As exemplified by the current rate case of National Grid-Boston Gas (DPU 20-120), LDCs can be expected to petition the DPU for two types of unprecedented relief due to the risks inherent in the current situation: (i) higher rates of return on equity, and (ii) accelerated rates of capital-cost recovery through depreciation. These requests reflect the gas industry's growing concern with fully recovering investments and attracting sufficient investment capital considering the transition underway to a low-carbon economy. If approved, each of these changes will necessarily raise customer gas rates through the medium term. Even though the overall return on their pipe replacement will not change, shorter asset lives will put downward pressure on the longer-term earnings of gas companies.

b) Cost recovery challenges, including that of stranded costs, are likely to be substantial as demand for fossil gas inevitably declines and the gas customer base contracts as part of transformative change toward a low-carbon economy. Independent studies confirm that customer gas and electricity rates are already nearing an inflection point as electricity becomes less expensive than gas.

c) For ratepayers, cost recovery challenges for LDC investors and rising gas rates relative to electricity rates foreshadow negative distributional consequences with likely regressive cost burdens for gas customers. Low-income households are likely to be unable to leave the gas system because of high upfront electrification costs or because their landlords fail to invest in cleaner, energy-efficient heating and cooling solutions.

6. GSEP and the DPU's alignment with climate policy

a) The financial outlook and core business models of the Massachusetts gas industry are fundamentally challenged by the rapidly accelerating decarbonization of the energy sector, yet these considerations did not play a role in the DPU's 2020 GSEP proceedings, apart from important information requests by the Office of the Attorney General.

b) GSEP is one of the most expensive capital-intensive programs ever undertaken in the Commonwealth with substantial cost implications for ratepayers, but this mega-project continues to lack alignment with the most critical policy area relating to our future, namely, the state's mandated decarbonization goals.

B. Conclusions

GSEP has brought Massachusetts into an intensive, protracted gas infrastructure replacement cycle that today raises red flags. The program's original intent was sound: to enhance public safety and reduce the amount of methane leaked into the atmosphere by replacing leak-prone pipe on an accelerated basis. But the impact of the replacement activity on safety has been indeterminant, the sheer number of reported gas leaks has only minimally declined, and the three largest gas companies have so far been unable to meet the methane emission targets set by the Commonwealth's Department of Environmental Protection. The findings of this report also raise serious concerns about whether the program, taken as a whole, continues to be financially sound. It is clear that GSEP has become one of the largest, most expensive infrastructure projects ever undertaken in Massachusetts and the program is not receiving the scrutiny, analysis, and evaluation it warrants given its mega-project status.

This report offers the following conclusions:

GSEP is in dire need of systemic, state-wide evaluation that carefully considers the aggregate impact of the program and the likely future ramifications for both gas companies and ratepayers

(the "public"). While the DPU has been the industry policymaker and regulator, the agency offers little in the way of proactive, publicly released, evaluative analysis of the six LDC GSEP plans taken together. As a result, massive infrastructure decisions—totaling more than half a billion dollars annually—are being made in a piecemeal fashion. A critical program oversight question to be addressed at this juncture is the following: if GSEP had not been created in 2014, and instead gas companies had simply replaced their infrastructure at a slower rate under their normal rate programs, what infrastructure program, if any, would be recommended today? In other words, under what conditions would it be advisable to spend more than $500 million annually to replace failing gas infrastructure given the current transition away from fossil fuels?

A comprehensive assessment of the program should also produce guidelines for vastly improved oversight and management of the LDCs by their regulator. Guidelines could include, for example, improved pipe and leak classification systems, clear and strategic criteria for prioritizing leak repair vs. pipe replacement projects based on both safety considerations and climate-damage impact, spending limitations ensuring that new GSEP costs are not incurred for projects that fail to meet prioritized repair/replacement criteria, and rigorous program target goals and benchmarks tied to consistently measured and monitored metrics. The extensive data collection undertaken for this report required painstaking investigation precisely because of the dearth of rigorous, consistent reporting and metrics that would otherwise allow policymakers and the public to understand what outcomes GSEP has delivered over time, how much the program is costing, and how it is impacting retail gas rates. As this report shows, important programmatic details and statistics documenting concrete outcomes are buried in hundreds of pages of docket proceedings.

This report also raises serious concerns about whether GSEP, taken as a whole, is still financially and programmatically sound. In 2021, $570.4 million is expected to be spent by the six LDCs to replace 266 miles of pipeline and associated services. Since 2015, 1,348 miles have been replaced, but more than 5,300 miles remain to be replaced by the program's extended end date of 2039. Unit costs for pipeline replacement have been increasing on the order of 17 percent annually for the largest LDCs. In 2020, these costs reached $2.6 million per mile for National Grid-Boston Gas, the largest LDC in the Commonwealth and the company responsible for about 60 percent of the state's leak-prone pipe. Replacement rates and depreciation practices have become unrealistic relative to the actual useful life of these assets, considering both the physical deterioration and technical obsolescence of the existing gas distribution infrastructure as well as the Commonwealth's mandated greenhouse gas emission limits.

In sum, GSEP is on a course to generate unrecoverable costs, an outcome with potentially serious inequities for ratepayers. Lower-income households are likely to have the most difficulty switching to lower-cost, cleaner energy systems due to higher upfront costs and the likely reluctance of landlords to invest in weatherization and new thermal energy systems.

There is no dispute that safety must remain the essential priority of the gas companies and the DPU. **The largest, most hazardous, and climate-damaging leaks need to be aggressively identified and fixed. To accomplish this, correcting two underlying price regulation distortions is critical: (i) GSEP's financial incentive to replace rather than repair leaking infrastructure should be reversed, and (ii) "lost gas" from leaks should no longer be treated as a normal cost of doing business to be entirely**

passed on to ratepayers. These perverse incentives stand in the way of creating effective incentives to strategically and successfully repair leaks (especially superemitters) and to monitor those repairs.[167]

The DPU's recently broadened mandate to balance equity, security, and reductions in greenhouse gas emissions with its longstanding priorities of safety, reliability, and affordability creates an immediate imperative for rethinking GSEP's "business-as-usual" approach to replacing gas pipes and associated infrastructure. During one of the 2020 LDC GSEP proceedings, the Office of the Attorney General underscored this very point:

> As we plan for and transition to a net-zero carbon energy future, the gas distribution companies have a public service obligation to invest prudently and minimize future stranded costs. This obligation includes thinking realistically and holistically about the future before making capital investment decisions.[168]

The fact that GSEP is neither aligned or integrated with the Commonwealth's climate goals must be addressed: the underlying premise of GSEP—the indefinite continuation of the fossil gas distribution network—is irreconcilably at odds with the Commonwealth's climate-related mandates and the urgency of needed state policy action to dramatically reduce greenhouse gas emissions. Furthermore, Massachusetts' mandatory emissions reduction goals will inevitably require decommissioning at least some parts of the Commonwealth's fossil fuel infrastructure. But while the Commonwealth has set aggressive targets for building electrification, it has yet to establish targets for decommissioning the fossil fuel infrastructure that will be displaced by electrification.

The Governor, the Executive Office of Environment and Environmental Affairs, the DPU, and the legislature need to take a hard look at GSEP and its future viability in light of the significant market and policy forces reshaping our energy future. Much work remains to be done to determine how to efficiently, equitably, and safely create an energy transition for the Commonwealth that balances the interests of society at large, existing and future energy customers, and the shareholders of energy utilities. Rethinking GSEP offers an important opportunity for state government, utilities, and other investors to work together to shape the Commonwealth's energy transition by **redirecting GSEP financing away from sustaining an outdated, failing gas distribution system and toward investments in renewable, zero-emission energy for all.**

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[167] For an example of a legislative incentive proposal, see An Act Relative to the Future of Heat in the Commonwealth, H.3298/S.2148, 192nd General Court (March 2021), joint petition of Rep. Lori A. Ehrlich and Sen. Cynthia Stone Creem, https://malegislature.gov/Bills/192/HD3472.

[168] DPU 20-GSEP-04, Initial Brief of the Office of the Attorney General, filed 3/9/21, 9, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13239787.