



The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 24-GSEP-03

April 30, 2025

Petition of Boston Gas Company d/b/a National Grid for Approval of its 2025 Gas System Enhancement Plan, pursuant to G.L. c. 164, § 145, for rates effective May 1, 2025.

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SUMMARY

Through these orders, the Department of Public Utilities directs significant changes in the gas system enhancement plans (“GSEPs”), which the Massachusetts natural gas utilities use to recover costs associated with their work repairing and replacing existing gas distribution pipelines. We act today to ensure energy affordability and to protect public safety, all while complying with the Commonwealth’s laws that require reductions in greenhouse gas emissions.

These orders change course from recent years’ GSEPs, as required by the Legislature and as informed by robust public process. The 2022 Climate Act directed the Department to convene the GSEP Working Group, which held ten meetings from April 2023 to January 2024 to review the GSEP program. The final report of the GSEP Working Group made many consensus recommendations to improve the GSEP program, which the Legislature enacted as part of the 2024 Climate Act. These amendments address several needed areas of reform, including ratepayer affordability, the avoidance of stranded assets, and the need for a remediation strategy for leak-prone pipe that departs from the current heavy reliance on pipe replacement. With the adoption of the 2024 Climate Act, it is now our responsibility to implement these important reforms.

The GSEP Working Group process, the Legislature’s actions, and the record in these cases point to significant flaws in the existing GSEP program, which our orders today will remedy. Fundamentally, the GSEP program as currently implemented is not striking a good balance between safety and affordability, given the escalating costs and limited progress in addressing leak-prone pipe. Since the program’s inception a decade ago, the utilities’ spending on the program has increased markedly—doubling between 2015 and 2023—with greater increases projected in 2024 and 2025. At the same time, the benefits from the program, in the form of miles of main and services replaced, have not increased similarly. The record in this case and our decision below discuss this inefficient spending in extensive detail. At a time of rising costs, our duty is to ensure the wise spending of ratepayer dollars by reforming and refocusing the GSEP program.

We therefore take five significant actions in these proceedings to substantially reform the GSEP process:

- (1) Reducing from 3.0 percent to 2.5 percent the revenue cap that sets the upper limit on annual GSEP-related spending, which will result in near-term reductions to customer bills;
- (2) Allowing spending in excess of the newly established 2.5 percent revenue cap up to 3.0 percent for non-pipeline alternatives, *i.e.*, NPAs, which will encourage gas companies to consider solutions that avoid additional investment in fossil fuel infrastructure;

- (3) Eliminating carrying charges on deferred GSEP expenditures, which will provide a strong incentive for the gas companies to control costs and evaluate solutions that address leak-prone pipe in a more affordable manner;
- (4) Requiring a more rigorous risk prioritization process for GSEP projects, which will ensure that the safety of the gas distribution system is maintained even as GSEP-related spending declines over time; and
- (5) Imposing the express requirement that the gas utilities evaluate advanced leak repair technology as an alternative to pipe replacement, which will result in more affordable solutions for customers and avoid unnecessary investment in potential stranded assets.

The Department is confident that these actions will set the GSEP program on a more sustainable trajectory, ensuring that the program is affordable for ratepayers, maintains focus on public safety, and aligns with the Commonwealth's climate policies.

I. INTRODUCTION

On October 31, 2024, Boston Gas Company doing business as National Grid (“National Grid” or “Company”) filed a petition with the Department of Public Utilities (“Department”) pursuant to G.L. c. 164, § 145 (“Section 145”), for approval of its 2025 gas system enhancement plan (“GSEP”) to address aging or leaking natural gas pipeline infrastructure. The Company sought approval to collect \$203,002,671 for the former Boston Gas Company (“Boston Gas Division”) and \$17,058,686 for the former Colonial Gas Company (“Colonial Gas Division”) for effect on May 1, 2025, to recover the cost to replace or repair eligible leak-prone infrastructure for both divisions through the end of calendar year 2025 (Exh. NG-MS/CSS-2, at 1-2).¹ The Company’s proposed revenue requirement does not exceed the allowed 3.0 percent cap (Exhs. NG-MS/CSS-1, at 13; NG-MS/CSS-2, at 1-2).² To this revenue requirement, the Company added the estimated cost to repair Grade 3 leaks identified as having a significant environmental impact (“G3SEI leaks”) of \$1,148,708 for the Boston Gas Division and \$75,146 for the Colonial Gas Division, resulting

¹ Boston Gas and Colonial Gas Company were previously separate affiliates operating within the holding company system of National Grid USA. Effective March 15, 2020, the former Colonial Gas Company merged with Boston Gas, with Boston Gas as the surviving legal entity, as approved by the Department in Boston Gas Company and Colonial Gas Company, D.P.U. 19-69 (2019). We refer to them separately by “division” in this Order, as they have one coordinated GSEP with individual replacement schemes and individual gas system enhancement adjustment factors for each division.

² In Boston Gas Company and Colonial Gas Company, D.P.U. 18-GSEP-03, at 21 (2019), the Department found that the use of a 3.0 percent cap was consistent with the intent of Section 145. See also M.D.P.U. No. 60.9, § 9.0.

in a net amount to be collected through the gas system enhancement adjustment factors (“GSEAFs”) of \$204,151,379 for the Boston Gas Division and \$17,133,832 for the Colonial Gas Division (Exhs. NG-MS/CSS-1, at 6, 12; NG-MS/CSS-2, at 1-2; NG-MS/CSS-5, Line 6; NG-GPP-2, at 15). Based on the Company’s proposed revenue requirement, it proposes to implement, for the Boston Gas Division, GSEAFs per therm of \$0.2208 for residential customers, \$0.2188 for small commercial and industrial (“C&I”) customers, \$0.1886 for medium C&I customers, \$0.1701 for large C&I customers, and \$0.1302 for extra-large C&I customers, and for the Colonial Gas Division, GSEAFs per therm of \$0.0746 for residential customers, \$0.0636 for small C&I customers, \$0.0612 for medium C&I customers, and \$0.0257 for large C&I customers (Exh. NG-MS/CSS-5). The general terms of the Company’s GSEP and the formula for calculation of its GSEAFs are set forth in its local distribution adjustment clause (“LDAC”) tariff, M.D.P.U. No. 60.9, § 9.

The Department has docketed this matter as D.P.U. 24-GSEP-03. In addition to National Grid, the other local distribution companies (“LDCs”) that petitioned for approval of their respective GSEPs are: Fitchburg Gas and Electric Light Company d/b/a Unitil (D.P.U. 24-GSEP-01); The Berkshire Gas Company (“Berkshire”) (D.P.U. 24-GSEP-02); Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty (D.P.U. 24-GSEP-04); Eversource Gas Company of Massachusetts d/b/a Eversource Energy (D.P.U. 24-GSEP-05); and NSTAR Gas Company d/b/a Eversource Energy (“NSTAR Gas”) (D.P.U. 24-GSEP-06).

On September 13, 2024, the Department issued a procedural memo outlining additional testimony and supporting documentation that each LDC was required to submit at its initial filing. D.P.U. 24-GSEP-03, 2025 GSEP Filings – Procedural Memo (September 13, 2024). Also on September 13, 2024, the Attorney General of the Commonwealth of Massachusetts (“Attorney General”) submitted a notice of intervention pursuant to G.L. c. 12, § 11E. On November 21, 2024, the Department approved the notice of the Attorney General for retention of experts and consultants at funding not to exceed \$150,000, filed pursuant to G.L. c. 12, § 11E(b). D.P.U. 24-GSEP-03, Stamp Approval of Attorney General’s Notice of Retention of Experts and Consultants (November 21, 2024). Pursuant to notice duly issued, the Department provided an opportunity for public comment.³ On November 29, 2024, the Department granted intervention to the United Joint Petition of United Steelworkers and Utility Workers’ Union of America Locals 318, 350, and 369 (“Unions”), Conservation Law Foundation (“CLF”), and Sierra Club.⁴

³ The Department received written comments from interest groups, businesses, labor unions, individual ratepayers, and elected officials concerning the GSEPs. Commenters expressed concern regarding the costs of the plans given the Commonwealth’s transition to electrification. Several commenters expressed support for the GSEPs as essential for pipeline safety. The Department appreciates the thoughtful comments provided by these groups and individuals. The Department will address any specific comments, as necessary, in the sections below.

⁴ On December 6, 2024, the LDCs filed an appeal encompassing all six GSEP dockets requesting that the Commission overturn the Hearing Officer’s Ruling granting intervention to CLF and Sierra Club. On December 11, 2024, CLF and Sierra Club filed a joint reply to the LDCs’ appeal. On January 27, 2025, the Commission issued an Interlocutory Order denying the LDCs’ appeal. D.P.U. 24-GSEP-01 through

D.P.U. 24-GSEP-03, Hearing Officer Stamp Approval of Unions' Petition to Intervene (November 29, 2024); D.P.U. 24-GSEP-03, Hearing Officer Ruling on Petitions to Intervene of CLF and Sierra Club (November 29, 2024).

In support of its filing, the Company sponsored the testimony of Amy Smith, director, gas strategy and external stakeholder engagement New England gas; Michael Tupper, director, gas distribution asset management and engineering for Massachusetts; Faye Brown, director, gas planning and design engineering for Massachusetts; Mei Sun, manager, New England revenue requirements; and Cody S. Strong, senior analyst, New England gas pricing group. On March 7, 2025, the Department held a joint evidentiary hearing for the six LDCs. On March 24, 2025, the Company, the Attorney General, CLF, Sierra Club, and Unions submitted initial briefs. On March 31, 2025, National Grid submitted a reply brief jointly with the other LDCs, the Attorney General submitted a reply brief, and CLF and Sierra Club together submitted a reply brief.⁵ The record consists of the Company's initial filing, the LDCs' joint response to the Procedural Memo and rebuttal testimony, the Attorney

D.P.U. 24-GSEP-06, Interlocutory Order on Appeal of Hearing Officer Ruling on Petitions for Intervention (January 27, 2025).

⁵ Because the LDCs jointly submitted a reply brief, the Department references them collectively as "LDCs." Similarly, the Attorney General, CLF, and Sierra Club each submitted briefs covering all GSEP dockets, so their respective arguments reference the LDCs collectively.

General's direct and surrebuttal testimony, Sierra Club's direct and surrebuttal testimony, and the Company's responses to 75 information requests and three record requests.⁶

II. STATUTORY REQUIREMENTS

To promote public safety and to reduce lost and unaccounted for ("LAUF") natural gas, Section 145 requires gas distribution companies to submit to the Department plans to address aging or leaking natural gas infrastructure.⁷ On or before October 31, a gas company may file a plan for the subsequent construction year, i.e., the GSEP.

Section 145(d). The Department must review the GSEP within six months. Section 145(d).

The GSEP is effective as of the date of filing, pending Department review. Section 145(d).

The Department may modify the GSEP prior to approval at the request of a gas company or

make other modifications to the GSEP as a condition of approval. Section 145(d). The

Department is required to consider the costs and benefits of the GSEP including, but not

limited to, impacts on ratepayers, reductions of LAUF natural gas through a reduction in

natural gas system leaks, improvements to public safety, and reducing greenhouse gas

emissions in compliance with the limits and sublimits established in chapter 21N.

G.L. c. 25, § 1A; Section 145(d). The Department is also required to give priority to

⁶ At the evidentiary hearing, the Department moved these exhibits into the record (Tr. 1, at 185).

⁷ On November 20, 2024, Governor Healey signed an Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers, St. 2024, c. 239 ("2024 Climate Act"), which amended Section 145. The effective date of the changes was February 18, 2025. Because this proceeding covers calendar year 2025, we have considered the amended Section 145 in our analysis.

GSEPs narrowly tailored to addressing leak-prone infrastructure most immediately in need of remediation. Section 145(d). If a GSEP complies with Section 145, and the Department determines that it operates in a balanced manner to reasonably accelerate eligible infrastructure measure and provides benefits to customers, the Department must preliminarily accept the GSEP either in whole or in part. Section 145(e). The gas company may begin recovering the estimated revenue requirement beginning on May 1 of the year following the submission of the GSEP. Section 145(e).

Subsequently, on or before May 1 of each year, the gas company must file final project documentation for construction completed in the previous calendar year to demonstrate substantial compliance with the GSEP and to demonstrate that the costs were reasonably and prudently incurred, i.e., the GREC. Section 145(f). The Department must review the GREC within six months. Section 145(f). In reviewing the prior year's construction costs and any associated proposed rate change, the Department shall determine whether the gas company has over- or under-collected its requested revenue requirement. Section 145(g). If the Department determines that any of the costs were not reasonably or prudently incurred, the Department shall disallow the costs and direct the gas company to refund the full value of the costs charged to ratepayers with the appropriate carrying charges (interest) on the over-collected amounts. Section 145(g). A company may nonetheless be allowed to recover the disallowed costs in a future proceeding where it demonstrates through additional evidence that the costs were reasonably and prudently incurred. Section 145(g). If the Department determines that any of the costs did not comply with the approved GSEP,

however, the Department shall disallow the costs from the cost recovery mechanism with no future opportunity for recovery through the cost recovery mechanism and shall direct the gas company to refund the full value of the costs charged to ratepayers with the appropriate carrying charges (interest) on the over-collected amounts. Section 145(g). The Department may also discontinue the GSEP and require a gas company to refund any costs charged to customers due to failure to substantially comply with the approved GSEP or failure to reasonably and prudently manage project costs. Section 145(h).

The GSEP shall include, but not be limited to, the following: (i) eligible infrastructure measures⁸ concerning mains, services, meter sets, and other ancillary facilities

⁸ Section 145(a) defines eligible infrastructure measure as:

a replacement, retirement[,] or an improvement of existing infrastructure of a gas company that: (i) is made on or after January 1, 2015; (ii) is designed to improve public safety or infrastructure reliability; (iii) does not increase the revenue of a gas company by connecting an improvement for a principal purpose of serving new customers; (iv) reduces, or has the potential to reduce, [LAUF] natural gas through a reduction in natural gas system leaks; (v) is not included in the current rate base of the gas company as determined in the gas company's most recent rate proceeding; (vi) may include use of advanced leak repair technology approved by the department to repair an existing leak-prone gas pipe to extend the useful life of such gas pipe by no less than ten years; and (vii) may include replacing gas infrastructure with utility-scale non-emitting renewable thermal energy infrastructure.

composed of non-cathodically protected steel,⁹ cast iron,¹⁰ and wrought iron,¹¹ prioritized to implement the distribution pipeline integrity management plan (“DIMP”)¹² annually submitted

⁹ Cathodic protection is a technique to reduce the corrosion of a metal surface by making that surface work as the cathode of an electrochemical cell. NACE International SP0169-2013, Standard Practice, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” at § 2, revised October 4, 2013.

¹⁰ This category applies to gray-cast iron that is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal. American Gas Association, Gas Piping Technology Committee, Guide for Gas Transmission Distribution, and Gathering Piping Systems, at § 192.3, Subpart A, Glossary of Commonly Used Terms, https://www.aga.org/wp-content/uploads/2023/02/ANSI-GPTC-Z380-1-2022-Addendum-2-02_02_23.pdf (Updated February 2023). Cast iron is relatively brittle and is susceptible to stress cracking under high-pressure situations. U.S. Department of Transportation, Pipeline & Hazardous Materials Safety Administration, Pipeline Glossary, <https://primis.phmsa.dot.gov/comm/glossary/index.htm#CastIron> (last visited March 13, 2025).

¹¹ Together with cast iron, wrought iron pipelines are among the oldest energy pipelines constructed in the United States. The degrading nature of iron alloys, the age of the pipelines, and the pipe joint designs have greatly increased the risk involved with the continued use of such pipelines. United States Department of Transportation, Pipeline & Hazardous Materials Safety Administration, Pipeline Replacement Background, available at: https://opsweb.phmsa.dot.gov/pipeline_replacement/default.asp (last updated September 11, 2024).

¹² LDCs are required to adopt a written integrity management plan, *i.e.*, the DIMP, under federal pipeline safety regulations 49 C.F.R. § 192.1007. Each LDC’s DIMP must contain procedures for developing and implementing several elements including identifying threats and ranking risk. Under the federal regulations, LDCs are required to undertake a risk-based assessment of the distribution system and to identify threats to the system in seven categories, which are corrosion, natural forces, excavation damage, other outside force damage, material and weld failure, equipment failure and malfunction, and inappropriate operation. 49 C.F.R. § 192.1007(b). See, e.g., D.P.U. 24-GSEP-04, Exh. LU-NMW-2, at 20; D.P.U. 24-GSEP-06, Exh. ES-RJB-1, at 35. The federal regulations require evaluation and prioritization of

to the Department, and consistent with 49 C.F.R. §§ 192.1001 through 192.1015; (ii) an anticipated timeline for the completion of each project; (iii) the estimated cost of each project; (iv) rate change requests; (v) a description of customer costs and benefits, including the costs of potential stranded assets and the benefits of avoiding financial exposure to such assets; (vi) the relocations, where practical, of a meter located inside of a structure to the outside of said structure for the purpose of improving public safety; and (vii) any other information the Department considers necessary to evaluate the GSEP or GREC.

Section 145(c).

Each gas company's GSEP shall also include interim targets, which the Department must review to ensure that each gas company is meeting the appropriate pace to reduce the leak rate in a safe and timely manner and comply with the limits and sublimits established pursuant to G.L. c. 21N. Section 145(b).¹³ These interim targets shall be for periods of not more than six years and shall be incorporated into timelines for removing or remediating all leak-prone infrastructure. Section 145(b). If a gas company fails to meet these interim

the risk that these threats pose and the implementation of measures to address the highest risks with an emphasis on leak management, enhanced damage prevention, operator qualification to reduce human error, and system replacement. 49 C.F.R. § 192.1007(c), (d). See, e.g., D.P.U. 24-GSEP-04, Exh. LU-NMW-2, at 20; D.P.U. 24-GSEP-06, Exh. ES-RJB-1, at 35.

¹³ The Secretary of Energy and Environmental Affairs established a relevant sublimit for emissions from the natural gas distribution systems (i.e., emissions from leaks on distribution and service lines on the distribution system) in the Massachusetts Clean Energy and Climate Plan for 2025 and 2030, at 22-23, which can be found at <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030> (last visited March 1, 2025).

targets, the Department may levy a penalty up to 2.5 percent of the gas company's transmission and distribution service revenues for the previous calendar year.

Section 145(b).

III. COMPANY PROPOSAL

National Grid distributes natural gas to approximately 950,000 customers in 144 cities and towns (Exh. NG-GPP-2, at 9). As of December 31, 2023, the Company owns and operates 7,281 miles of distribution mains and 570,269 services for the Boston Gas Division and 3,935 miles of distribution mains and 203,378 services for the Colonial Gas Division (Exh. NG-GPP-2, at 10). For the Boston Gas Division, National Grid states that approximately 13.2 percent (958 miles) of the distribution system mains consist of non-cathodically protected steel, 18.6 percent (1,351 miles) consist of cast iron and wrought iron, and 2.4 percent (177 miles) consist of pre-1985 Aldyl-A plastic, which means that approximately 34 percent of the distribution system mains consist of leak-prone pipe (Exh. NG-GPP-2, at 10). For the Colonial Gas Division, National Grid states that approximately 1.4 percent (57 miles) of the distribution system mains consist of non-cathodically protected steel, approximately 1.4 percent (56 miles) consist of cast iron and wrought iron, and approximately 4.7 percent (183 miles) consist of pre-1985 Aldyl-A plastic, which means that approximately seven percent of the distribution system mains consist of leak-prone pipe (Exh. NG-GPP-2, at 10).

The Department has approved a timeline for completion of all current leak-prone pipe replacement for the Boston Gas Division by 2039 (Exh. NG-GPP-2, at 18). Boston Gas

Company and Colonial Gas Company, D.P.U. 17-GSEP-03, at 25-26 (2018). The Department has approved a timeline for completion of all current leak-prone pipe replacement for the Colonial Gas Division by 2034 (Exh. NG-GPP-2, at 18). Boston Gas Company and Colonial Gas Company, D.P.U. 19-GSEP-03, at 30 (2020). In the current GSEP, the Company anticipates replacing 120 miles of leak-prone mains and associated services in 2025 for the Boston Gas Division and 7 miles of leak-prone mains and associated services in 2025 for the Colonial Gas Division (Exh. NG-GPP-8, at 1).

National Grid proposes to recover a GSEP revenue requirement of \$203,002,671 for the Boston Gas Division and \$17,058,686 for the Colonial Gas Division (Exh. NG-MS/CSS-2, at 1-2). For the Boston Gas Division, the Company proposes the inclusion of costs for advanced pipe lining to repair half a mile of cast iron main and for the cast iron joint sealing robot (“CISBOT”) to repair 685 cast iron joints as part of its 2025 GSEP revenue requirement, consistent with An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 (“2022 Clean Energy Act”), which modified the definition of an eligible infrastructure replacement project to authorize the use of advanced leak repair technology to repair mains (Exhs. NG-GPP-2, at 3-6, 43; NG-GPP-6; NG-GPP-7; NG-GPP-8). The revenue requirement incorporates recovery of depreciation, property taxes, and pre-tax return, less a calculation of operations and maintenance savings (Exh. NG-MS/CSS-1, at 7-11). National Grid then added \$1,148,708 to its Boston Gas Division revenue requirement and \$75,146 to its Colonial Gas Division revenue requirement to account for the cost of proposed repairs of the G3SEI leaks (Exhs. NG-GPP-2, at 15;

NG-MS/CSS-2, at 1-2). The Company's final requested revenue requirements are \$204,151,379 for the Boston Gas Division and \$17,133,832 for the Colonial Gas Division (Exhs. NG-MS/CSS-1, at 6; NG-MS/CSS-2, at 1-2; NG-MS/CSS-5).

IV. REVENUE CAP

A. Introduction

Section 145(f) limits the annual change in an LDC's GSEP revenue requirement to:

(i) 1.5 percent of the gas company's most recent calendar year total revenues for firm service, including gas revenues attributable to sales and transportation customers; or (ii) an amount determined by the Department that is greater than 1.5 percent of the gas company's most recent calendar year total revenues for firm service, including gas revenues attributable to sales and transportation customers. In D.P.U. 18-GSEP-04, at 28-29, the Department determined that use of a 3.0 percent GSEP cap was reasonable and consistent with the intent of Section 145. National Grid presented a GSEP revenue requirement of \$204,151,379 for Boston Gas and \$17,133,832 for Colonial Gas, which did not exceed the 3.0 percent cap (Exhs. NG-MS-CSS-2, at 1-2; NG-MS-CSS-1, at 6, 12-13).

B. Positions of the Parties

1. Attorney General

The Attorney General urges the Department to reduce the revenue cap over the next three years to the statutory minimum of 1.5 percent of an LDC's most recent calendar year total firm revenues, arguing that circumstances have sufficiently changed since the cap was increased to 3.0 percent in 2019 (Attorney General Brief at 2, 32-33, citing

D.P.U. 18-GSEP-01, at 24-27; Attorney General Reply Brief at 15). Specifically, the Attorney General recommends that the Department lower the cap to 2.5 percent in these proceedings, with further reductions to 2.0 percent and 1.5 percent in the 2026 and 2027 GSEPs, respectively (Attorney General Brief at 35; Attorney General Reply Brief at 17).

The Attorney General recommends that the Department direct the LDCs to resubmit the 2025 GSEPs to reflect a 2.5 percent cap (Attorney General Brief at 40).

The Attorney General maintains that the plain language of Section 145(f) gives the Department discretion to lower the cap to the statutory minimum of 1.5 percent (Attorney General Reply Brief at 12-13). Further, the Attorney General takes issue with the LDCs' assertion that circumstances have not changed since the revenue cap was raised in 2019 (Attorney General Reply Brief at 15). The Attorney General contends that there have been numerous changes highlighting that the LDCs may no longer do business as usual, including climate mandates to significantly reduce the Commonwealth's GHG emissions, amendments to Section 145 to comply with G.L. c. 21N and to require the analysis of potential stranded costs, and Orders by the Department (Attorney General Brief at 5, citing An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8, § 87 ("2021 Climate Act"); 2022 Clean Energy Act; An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers, St. 2024, c. 239, § 81 ("2024 Climate Act"); Massachusetts Clean Energy and Climate Plan for 2025 and 2030; D.P.U. 20-80-B at 18; Attorney General Reply Brief at 15). The Attorney General argues that lowering the revenue cap will reduce ratepayers' costs and align the GSEP with the Commonwealth's climate

mandates (Attorney General Brief at 36; Attorney General Reply Brief at 16-17). The Attorney General also asserts that lowering the revenue cap would force the LDCs to consider less expensive alternatives to replacement and focus on “worst first” pipe replacement (Attorney General Brief at 36).

The Attorney General disputes the LDCs’ assertion that lowering the cap would increase the timeline for replacing or remediating all leak-prone pipe and result in more frequent base distribution rate cases (Attorney General Brief at 38, citing Exh. AG-DL-DM-1, at 10–12). The Attorney General argues that the LDCs’ assertions are predicated on the assumption that the LDCs will continue to replace all leak-prone pipe with new pipe, which may not be the case as the Commonwealth transitions to electrification and as the LDCs decommission leak-prone pipe without replacement (Attorney General Brief at 38-39).

In addition, the Attorney General recommends that the Department deny recovery of carrying charges for any deferred amounts above the cap (Attorney General Brief at 35-36; Attorney General Reply Brief at 17-18). The Attorney General contends that denying the LDCs carrying charges on any deferred amounts over the cap would curb the LDCs’ GSEP spending and ensure prudent cost management (Attorney General Brief at 38).

2. CLF and Sierra Club

CLF and Sierra Club agree with the Attorney General’s recommendation that the Department gradually lower the GSEP revenue cap from 3.0 percent to the statutory minimum of 1.5 percent to align with climate targets and customer protection (CLF Brief

at 10; Sierra Club Brief at 19-20; CLF/Sierra Club Reply Brief at 7, citing Attorney General Brief at 35). CLF and Sierra Club assert that the 3.0 percent cap is no longer consistent with the Commonwealth's climate laws and regulations (CLF Brief at 10, Sierra Club Brief at 19-20; CLF/Sierra Club Reply Brief at 7, citing Attorney General Brief at 35).¹⁴ CLF and Sierra Club also join in support of the Attorney General's recommendation that the LDCs should be required to resubmit their GSEPs using a 2.5 percent cap (CLF/Sierra Club Reply Brief at 7). Sierra Club claims that lowering the GSEP cap would require the LDCs to prioritize high-risk projects and encourage fewer GSEP-funded upgrades that would become stranded assets in the future, while still allowing for significant GSEP investment (Sierra Club Brief at 20). Sierra Club asserts, however, that the Department should consider an exception to the 1.5 percent cap for repairs, non-pipeline alternatives ("NPAs"), and retirements, allowing recovery up to 3.0 percent for the costs associated with these categories of measures (Sierra Club Brief at 20).

In addition, Sierra Club argues that the Department should consider changing the LDCs' tariffs to disallow carrying charges on the deferrals above the GSEP cap, as allowing carrying charge accrual on those deferrals undermines the revenue cap function as a meaningful control on GSEP spending (Sierra Club Brief at 20; CLF/Sierra Club Reply Brief at 7, citing Attorney General Brief at 35-35). Sierra Club rejects the LDCs' position that, in

¹⁴ In its initial brief, Sierra Club recommends that lowering the GSEP revenue cap from 3.0 percent to 1.5 percent take place by 2028 (Sierra Club Brief at 20). In its reply brief, submitted jointly with CLF, this referenced year is omitted (CLF/Sierra Club Reply Brief at 7).

the case of a cap reduction, they will continue to exceed the GSEP cap, with cost deferrals continuing to accrue interest, as well as the LDCs' position that a cap reduction requires an extension of the GSEP timeline (Sierra Club Brief at 21). Sierra Club avers that these positions assume that the LDCs will not alter their strategy of wholesale replacement of leak-prone pipe under the GSEP, and states that these issues could be addressed by shifting the focus of GSEP remediations towards less expensive strategies, including strategic decommissioning, monitoring, repair, and NPAs (Sierra Club Brief at 21; CLF/Sierra Club Reply Brief at 7, citing Attorney General Brief at 23-24). In addition, Sierra Club asserts that lowering the GSEP revenue cap does not inhibit the LDCs' ability to comply with the DIMP, as compliance is not contingent upon GSEP funding (Sierra Club Brief at 21).

3. Unions

The Unions assert that although environmental concerns and lowering ratepayer costs are laudable goals, the record demonstrates that the proposed changes to the GSEPs would be a grave mistake because the safety and reliability concerns related to the Commonwealth's aging distribution infrastructure have not gone away (Unions Brief at 2, citing Exh. LDC-Rebuttal-1, at 23). The Unions maintain that Massachusetts has some of the oldest natural gas infrastructure in the nation and continues to have a disproportionately high percentage of leak-prone pipe compared to the national average (Unions Brief at 2, citing Exhs. LDC-Rebuttal-1, at 9-10; LU-KMJ-1, at 7-8; Tr. at 181-182). The Unions contend that lowering the revenue cap will reduce the amount of leak-prone pipe that can be replaced

each year, which increases risk of pipe failure and compromises the LDCs' ability to complete the work by the statutory deadline pursuant to Section 145(c) (Unions Brief at 3-4).

4. Company

The LDCs point to the Department's Order increasing the revenue cap to 3.0 percent, which considered the intent of the Legislature in enacting Section 145 and noted the importance of providing a reasonable opportunity to recover GSEP costs balanced against the potential bill impacts on ratepayers and the risk of rate shock caused by cost deferrals (LDCs Reply Brief at 69, citing D.P.U. 18-GSEP-06, at 27). The LDCs contend that they requested the revenue cap increase because it would allow the LDCs to avoid or mitigate future deferrals while facilitating timely achievement of the GSEP goals (LDCs Reply Brief at 69).

The LDCs argue that the Attorney General has provided no reliable evidence that would justify reducing the cap below 3.0 percent and that any Department departure from past precedent must be accompanied by an adequate statement of reasons, including a determination of each issue of fact or law necessary to the decision (LDCs Reply Brief at 72, citing G.L. c. 30A, § 11(8)). The LDCs maintain that the record evidence demonstrates that reducing the cap is contrary to the provisions of Section 145, inconsistent with the Commonwealth's climate goals, and harmful to customers from a risk and a financial perspective (LDCs Reply Brief at 73). In addition, the LDCs assert that there is no clear path for the Department to reach a different interpretation of Section 145(f) than it reached in D.P.U. 18-GSEP-06 (LDCs Reply Brief at 73). Specifically, the LDCs maintain that the circumstances that led to the Department's decision to increase the cap to 3.0 percent have

not changed in any manner (LDCs Reply Brief at 74). The LDCs also assert that the impetus for increasing costs associated with the GSEP are largely outside of their control (LDCs Reply Brief at 74).

The LDCs also maintain that the Department must consider that the LDCs have new obligations under the recently revised 220 CMR §§100.00 and 101.00, and a recent U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") rulemaking to implement revisions to their pipeline safety regulations, which further demonstrates that the need to identify and address risks on the system stands as a critically important obligation of each LDC and makes it clear that there is no legislative intent to de-prioritize public safety (LDCs Reply Brief at 74-75). Moreover, the LDCs argue that the 3.0 percent cap does not act as an incentive to spend more under the GSEP to reach the cap and that some of the LDCs' incremental GSEP revenue requirements have exceeded the cap due to the risks on the system that must be remediated or eliminated pursuant to their DIMP (LDCs Reply Brief at 75). In addition, the LDCs claim that a reduction of the revenue cap below 3.0 percent would have negative impacts for customers since the existing cap helps to minimize carrying charges (LDCs Reply Brief at 75). The LDCs further assert that a reduction of the revenue cap to 1.5 percent would mean that a majority of the LDCs would not be able to meet their long-term leak-prone pipe replacement and retirement goals within the 20- and 25-year timelines approved by the Department (LDCs Reply Brief at 75).

The LDCs maintain that if the Department were to reduce the revenue cap to 1.5 percent, they would need to file more frequent base distribution rate cases to recover the

costs associated with replacement of leak-prone pipe, in which case it would be likely that all the costs the LDCs incur would increase, leading to higher rates overall (LDCs Reply Brief at 76, citing Exh. LDC-Rebuttal-1, at 31). Under a lower revenue cap, the LDCs maintain that addressing the replacement of leak-prone infrastructure would occur over a longer timeline; customers would still incur these costs from base distribution rate case proceedings, but the more frequent and less gradual bill impacts are more difficult for customers to manage than the more predictable rate changes that result from the GSEP revenue cap (LDCs Reply Brief at 76, citing Exh. LDC-Rebuttal-1, at 31-32). In addition, the LDCs oppose the Attorney General's, CLF's, and Sierra Club's recommendation that the Department should require the LDCs to refile their 2025 GSEPs using a 2.5 percent revenue cap (LDCs Reply Brief at 72). The LDCs explain that such a proposal is inappropriate and unworkable in practice because they are already three months into the 2025 GSEP, and such a reduction at this point would be unnecessarily disruptive to the implementation of the 2025 GSEPs (LDCs Reply Brief at 72).

In response to the Sierra Club's recommendation that the Department grant an exception to the 1.5 percent revenue cap up to 3.0 percent of the LDCs' revenue requirement for all repairs, NPAs, and retirements, the LDCs assert that this recommendation is premised on an unfounded and incorrect assumption that they are not undertaking leak-prone pipe repairs or NPAs because those types of projects are less profitable than leak-prone pipe replacement (LDCs Reply Brief at 77, citing Exh. LDC-Rebuttal-1, at 74).

The LDCs argue that the Attorney General's suggestion that the Department is authorized to reject carrying charges on prudently incurred GSEP costs is also in clear conflict with the intent of Section 145 because the Legislature did not include any qualifiers on the term "costs," and where the meaning of the language chosen by the Legislature is plain and unambiguous, it is inappropriate to ascribe different intent to the use of the language (LDCs Reply Brief at 71, citing Sterilite Corporation v. Continental Casualty Company, 397 Mass. 837, 839 (1986)).

C. Analysis and Findings

1. Overview

In 2014, the Legislature enacted An Act Relative to Natural Gas Leaks (the "Gas Leaks Act"), which established the GSEP as an accelerated cost recovery mechanism aimed at repairing or replacing aging or leaking natural gas infrastructure, in the interest of public safety and to reduce LAUF natural gas. D.P.U. 14-130, at 2, citing Section 145(a). Absent the GSEP, each LDC would still be required to comply with its DIMP, which is primarily based on federal PHMSA requirements (Exh. DPU 2-6, Att.). 49 C.F.R. § 192.00. Without the accelerated, annual cost recovery allowed through the GSEP, each LDC would recover its pipeline replacement costs through traditional ratemaking in a base distribution rate case proceeding. Boston Gas Company et al., D.P.U. 10-55, at 119-120 (2010); Bay State Gas Company, D.P.U. 09-30, at 119-120 (2009); Bay State Gas Company, D.P.U. 05-27, at 45-49 (2005).

The Commonwealth's climate policies and strategies have evolved since 2014 when the Gas Leaks Act was enacted, including at least three significant legislative enactments since 2021. In determining the appropriateness of continuing the 3.0 percent revenue cap currently in place, the Department must take this legislative direction into account. The statutory history bearing upon the scope and structure of the GSEP program includes the following enactments.

The Global Warming Solutions Act of 2008 required the Secretary of the Executive Office of Energy and Environmental Affairs ("EEA") to adopt a 2020 statewide GHG emissions limit, and a plan for achieving said reduction. G.L. c. 21N, § 4(a); St. 2008, c. 298, § 6. At least once every five years thereafter, the EEA Secretary is required to update the plan for achieving the maximum technologically feasible reductions of GHG to implement the 2030, 2040, and 2050 statewide emission limits. G.L. c. 21N, § 4(h).

In 2021, the Legislature enacted the 2021 Climate Act, St. 2021, c. 8, which amended Chapter 21N to require the EEA Secretary to set statewide emissions limit and sector-specific sublimits every five years. The 2021 Climate Act further established the 2030 emissions limit at least 50 percent below the 1990 baseline and the 2040 emissions limit at least 75 percent below the 1990 level. EEA developed and finalized the Clean Energy and Climate Plan for 2050 ("CECP") in December 2022 to comply with the 2021 Climate Act.

The 2022 Clean Energy Act amended the Gas Leaks Act to require the gas distribution companies to consider including the use of advanced leak repair technology to repair any existing leak-prone gas pipe to extend the useful life of such gas pipe by no less

than ten years. 2022 Clean Energy Act, St. 2022, c. 179, § 58. The 2022 Clean Energy Act also authorized replacing gas infrastructure with utility-scale non-emitting renewable thermal energy infrastructure. 2022 Clean Energy Act, § 58.

Another provision of the 2022 Clean Energy Act required the Department to convene a stakeholder working group (“GSEP Working Group”) to “develop recommendations for regulatory and legislative changes that may be necessary to align [GSEPs] with the applicable statewide GHG emission limits and sublimits established pursuant to chapter 21N and the commonwealth’s emissions strategies.” 2022 Clean Energy Act, § 68. Of particular relevance to this issue, the GSEP Working Group in its Final Report and Recommendations presented to the Legislature on January 31, 2024¹⁵ adopted a recommendation proposed by the Attorney General and National Consumer Law Center to gradually phase out the 3.0 percent revenue cap according to the following schedule:

¹⁵ The Final Report and Recommendations of the GSEP Working Group is available at: <https://www.mass.gov/doc/gsep-working-group-final-report-and-recommendations-13124/download>.

Year	Percent of the gas company's most recent calendar year total firm revenues
October 1, 2024	2.8
October 1, 2025	2.5
October 1, 2026	2.0
October 1, 2027	1.5
October 1, 2028	1.0
October 1, 2029	0.5
October 1, 2030	0.0

Other elements of the GSEP Working Group recommendations were incorporated into the 2024 Climate Act. Among other things, the 2024 Climate Act adds an express requirement in the GSEP statute that the LDCs in their GSEPs “comply with the limits and sublimits established pursuant to chapter 21N of the general laws” (Section 145(b)), and further requires the Department to consider “the costs and benefits of the plan including . . . reducing greenhouse gas emissions in compliance with the limits and sublimits established in chapter 21N.” 2024 Climate Act, § 81; Section 145(d). The 2024 Climate Act also expressly modifies the requirement regarding a description of customer costs and benefits under the plan to include “the costs of potential stranded assets and the benefits of avoiding financial exposure to stranded assets.” 2024 Climate Act, § 81; Section 145(c). In addition, the 2024 Climate Act changes the defined term from “eligible infrastructure replacement” to “eligible infrastructure measure,” and adds “retirement” to the definition. 2024 Climate Act, § 81; Section 145(a). Other parts of Section 145 are modified to expressly include “remediating” in addition to removal or replacement (Sections 145(c) and (d)); “remediation”

rather than “replacement” (Section 145(d)); and elimination of “the replacement program” in favor of “a plan” (Section 145(h)). 2024 Climate Act, § 81. Finally, the 2024 Climate Act adds a requirement that the plan must “operate [] in a balanced manner” to reasonably accelerate infrastructure “measures” rather than “replacement” (Section 145(d)). 2024 Climate Act, § 81.

The Department also has acted to update its policies to support the Commonwealth’s efforts to meet its climate targets, with a special focus on the role of the LDCs going forward. See, e.g., Investigation into Role of Gas Local Distribution Companies as Commonwealth Achieves Target 2050 Climate Goals, D.P.U. 20-80-B (2023). The Department specifically stated that the ambitious mandates established by the Commonwealth require the LDCs to move beyond business as usual in their gas system planning. D.P.U. 20-80-B at 15. The Department also noted that it is important for the LDCs to move beyond business as usual toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth’s GHG emissions reduction targets. D.P.U. 20-80-B at 18. Based on these factors, the Department finds that the LDCs’ assertion that circumstances have not changed since the 3.0 percent cap was set in 2019 lacks merit.

The statutory revisions since adoption of the Gas Leaks Act in 2014, taken together, substantially redefine the purpose of GSEPs. It is no longer reasonable to proceed on the basis that leak-prone pipe must be remediated in a manner that presumes the existence of a natural gas distribution system in perpetuity. A remediation strategy that relies primarily

upon replacement of leak-prone pipe, rather than consideration of advanced leak repair technology, might be defensible under the statutory and regulatory regime in existence upon passage of the Gas Leaks Act in 2014. The position of the LDCs that “[r]epairs only defer inevitable replacement” (LDCs Reply Brief at 26) evinces a strategy that fails to minimize exposure to stranded assets and is inconsistent with reducing GHG emissions in compliance with the limits and sublimits established in Chapter 21N, both of which are required by the 2024 Climate Act. And a replacement strategy disregards the inclusion in the 2022 Clean Energy Act of advanced leak repair technology—which would extend the useful life of gas pipe rather than replace it—and thermal energy networks as “eligible infrastructure measures.” Finally, the Legislature in the 2024 Climate Act expressly substituted other solutions (e.g., “measure,” “retirement,” “remediation,” and “plan”) instead of the reliance on “replacement” formerly included in the GSEP statute. 2024 Climate Act, § 81. We cannot ignore this clear direction from the Legislature that the gas system enhancement process must be recalibrated to align with the restated objectives of the GSEP statute and the Commonwealth’s emissions reductions targets.

The 2024 Climate Act also requires that the Department determine that “the plan operates in a balanced manner,” which raises the issue of affordability. 2024 Climate Act, § 81. Natural gas customers in the Commonwealth experienced unusually large rate increases this past winter, due in large part to colder-than-normal weather and high natural gas prices, which resulted in large increases in the supply portion of customers’ bills. These increases were exacerbated by high costs included in the delivery portion of each customer’s

bill, due in large part to the charges associated with the GSEP program as the LDCs consistently spend at or above the 3.0 percent revenue cap.¹⁶ The replacement strategy followed by the LDCs is the most expensive path for customers, and the one most profitable for the LDCs given the earnings benefits of making a capital investment in new pipe having a useful life of fifty to sixty years (upon which the LDCs will earn a return), rather than incurring an operating expense to extend the life of an existing pipe for a few years until it can be decommissioned (as will be necessary for the LDCs to achieve compliance with the GHG emission limits and sublimits of Chapter 21N) (Tr. at 93-97). Consistent with the obligation imposed on the Department to find that the GSEPs operate in a balanced manner, and in light of the other statutory changes in the GSEP statute since 2014, there is an insufficient basis for the Department to retain the revenue cap at 3.0 percent.¹⁷

We note that in crafting the GSEP statute, the Legislature gave the Department discretion to raise the revenue cap above 1.5 percent by specifically stating “an amount

¹⁶ In the case of NSTAR Gas, for example, the GSEP-related charges represented about 36 percent of the local distribution adjustment charge (“LDAF”) on a typical customer’s bill (Exh. ES-ANB-2, at 1, 3).

¹⁷ The LDCs were put on notice that the Department would consider a reduction in the revenue cap in these proceedings. See, e.g., Procedural Memo at 4-5; D.P.U. 24-GSEP-01, Exhs. DPU 3-1; D.P.U. 24-GSEP-05, Exhs. DPU 2-8; DPU 5-1. In addition to discussion of the issue by the GSEP Working Group, the Attorney General raised the issue in the most recent GREC proceedings, where we determined there was insufficient record evidence to lower the cap at that time, noting instead that the Department would address the revenue cap in these proceedings. See, e.g., D.P.U. 24-GREC-04, at 22-23. Then in a procedural memo issued before LDCs submitted their initial filings in these proceedings, the Department directed the LDCs to provide additional evidence regarding the appropriate cap level. Procedural Memo at 4-5.

determined by the department.” Section 145(f). The Legislature included no requirement that the Department use any specific method to determine the appropriate amount. The LDCs correctly note that when the Department raised the revenue cap to 3.0 percent, we considered the intent of the Legislature in enacting Section 145, which was to accelerate the repair or replacement of aging or leaking natural gas infrastructure as well as to provide a reasonable opportunity for the recovery of associated costs by LDCs, balanced against the potential bill impacts on ratepayers and the risk of rate shock caused by cost deferrals.

D.P.U. 18-GSEP-01, at 25, citing Section 145(a), (b), (d), (g); D.P.U. 17-GSEP-01, at 13.

In raising the revenue cap, the Department also relied on the LDCs’ assertions that a 3.0 percent revenue cap would be high enough to avoid or mitigate future deferrals.

D.P.U. 18-GSEP-01, at 26-27, citing, e.g., D.P.U. 18-GSEP-06, RR-DPU-2. This assertion has not been borne out by actual experience, however. Instead, some of the LDCs continue to spend at a level that exceeds the revenue cap, even at 3.0 percent, thereby generating the deferrals that the 3.0 percent revenue cap was intended to avoid. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 22-GSEP-01, at 1-2; NSTAR Gas Company,

D.P.U. 21-GSEP-06, at 1-2, 15-16 (2022). The higher revenue cap adopted in 2019, rather than resulting in more miles of leak-prone pipe remediated each year, has simply resulted in the LDCs spending more money per mile, with the progress at remediating leak-prone pipe occurring at a pace that is largely unchanged from when the GSEP program was first initiated in 2015, as shown in Table 1 below.

Table 1

Year	Capital Spending (\$ millions)	Main Miles Replaced	Services
2015	291.6	221.24	11,119
2016	356.0	250.00	16,804
2017	416.7	280.30	18,708
2018	287.2	165.40	11,337
2019	418.5	214.89	13,995
2020	506.6	213.55	14,287
2021	510.9	255.30	17,619
2022	561.1	275.89	17,598
2023	583.7	268.50	16,519
2024 (est.)	791.0	266.77	
2025 planned	901.8	280.99	
TOTAL	5,625.1	2,692.83	137,986

Report to the Legislature on Prevalence of Natural Gas Leaks in the Natural Gas System,

D.P.U. 24-GLR-01, at 16-17 (2024) (“Gas Leaks Report”).¹⁸

Adding the tentative capital spending totals for 2024 and 2025 to the 2023 total brings total GSEP capital spending since 2015 to \$5.6 billion (in nominal dollars), a 21 percent year-over-year increase since the program’s inception. See Gas Leaks Report at 16-17. Yet

¹⁸ The Gas Leaks Act required the Department to annually submit a report addressing the prevalence of natural gas leaks, including the total number of Grade 1, Grade 2, and Grade 3 leaks, estimates for LAUF and methane emissions as a result of such leaks, and the time and cost estimates for eliminating the backlog of such leaks. Gas Leaks Report at 1. The Department incorporates the Gas Leaks Report into the record pursuant to 220 CMR 1.10(3).

the number of miles of main replaced has increased by only 27.0 percent over the same period, an annual increase of 2.70 percent. See Gas Leaks Report at 16-17.

The fundamental issue is the lack of any meaningful incentive for cost containment, given the accelerated rate recovery provided by the GSEP statute, which eliminates the regulatory lag associated with traditional ratemaking—the period between when a cost is incurred and the ability to recover that cost in rates in a subsequent rate proceeding—that provides an effective incentive for the LDCs to minimize costs. While the LDCs claim that they currently have sufficient incentives to minimize costs, the evidence suggests otherwise, given the continued reliance on pipe replacement to the exclusion of advanced leak repair technology notwithstanding the express authorization of that remediation strategy by the Legislature in the 2022 Clean Energy Act. See, e.g., D.P.U. 24-GSEP-02, Berkshire Brief at 37-38; D.P.U. 24-GSEP-06, NSTAR Gas Brief at 56-59. This lack of meaningful cost control incentive has resulted in a 162 percent increase in the cost per mile (inclusive of services and meters) in GSEP spending over the last decade, from \$1.32 million in 2015 to a projected \$3.46 million in 2025, as shown in Table 2 below. Inverting this ratio shows another way to look at this, namely, the change in the number of miles replaced per \$10 million of GSEP capital spending. As shown in Table 2 below, from the GSEP's inception to the projections for 2025, the number of miles replaced per \$10 million of GSEP expenditures has fallen 62 percent from roughly eight miles to less than three miles.

Table 2

Year	Spending per mile of distribution main installed (\$ millions) ¹⁹	Miles replaced per \$10 million
2015	1.32	7.59
2016	1.42	7.02
2017	1.49	6.73
2018	1.74	5.76
2019	1.95	5.13
2020	2.37	4.22
2021	2.00	5.00
2022	2.03	4.92
2023	2.17	4.60
2024 (estimated)	2.97	3.37
2025 (planned)	3.46	2.89

See Gas Leaks Report at 16-17.

Boston Gas Company's projected average cost for leak-prone pipe replacement for its 2025 GSEP work is \$4 million per mile, inclusive of meters and services. During the past five years, this cost has increased by 63 percent or 12.5 percent per year (Exh. AG 1-4).

Given the 4,049 miles of leak-prone pipe still remaining to be replaced, it will cost an estimated \$13.7 billion in additional GSEP spending if the LDCs continue down the current path of relying primarily on pipe replacement and failing to control costs in any meaningful manner. D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06, Exh. AG-DL-DM-1, at 31.

¹⁹ The spending per mile includes the cost to replace services plus related work. Gas Leaks Report at 16-17.

And this \$13.7 billion is relatively conservative, inasmuch as it assumes a 2.0-percent annual inflation rate as compared to the recent historic growth rate of GSEP capital spending of 11.9 percent annually D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06, Exh. AG-DL-DM-1, at 31. Ratepayers simply cannot afford to continue down this path, and the Department would be failing our obligation under the GSEP statute to ensure that plans operate in a balanced manner, if we do not take significant action in these proceedings to reform the GSEP process. In addition to addressing affordability, the Department has an obligation to implement the other elements in the GSEP statute included in the 2024 Climate Act, including the avoidance of stranded assets, taking action to achieve the GHG emission limits and sublimits established in Chapter 21N, and directing a remediation strategy for leak-prone pipe that moves away from the current heavy reliance on pipe replacement.

We are therefore taking five significant actions in these proceedings to substantially reform the GSEP process:

- (1) Reducing the revenue cap from 3.0 percent to 2.5 percent;
- (2) Allowing spending in excess of the newly established 2.5-percent revenue cap up to 3.0 percent for NPAs;
- (3) Eliminating carrying charges on deferred GSEP expenditures;
- (4) Requiring a more rigorous risk prioritization process for GSEP projects; and
- (5) Imposing the express requirement that as a matter of burden of proof, LDCs will be required to demonstrate evaluation of advanced leak repair technology as an alternative to pipe replacement.

These actions are described in more detail in the sections immediately below and in Sections IV.B.3. and V.3.

2. Reduction in the Revenue Cap

For the reasons set forth in the preceding discussion, we are reducing the revenue cap from 3.0 percent to 2.5 percent, consistent with the recommendations of the GSEP Working Group. We further express our intention that, absent compelling evidence in future GSEPs, it is likely that the Department will implement the recommendations from the GSEP Working Group to continue to lower the revenue cap to 2.0 percent for the 2026 GSEPs and to 1.5 percent for the 2027 GSEPs.

The Attorney General, Sierra Club, and CLF asked that the Department require each LDC to submit a revised GSEP reflecting the lowered cap (Attorney General Brief at 40; CLF/Sierra Club Reply Brief at 7). The LDCs assert that filing revised 2025 GSEPs is unworkable in practice (LDCs Reply Brief at 72). The Department finds that such a requirement is unnecessary and burdensome on the LDCs. The Department acknowledges that work on the 2025 GSEP is already underway. The Department has typically granted the LDCs some degree of flexibility concerning the GSEP projects approved in these Orders versus the actual GSEP projects completed during any given GSEP construction year. This flexibility should allow the LDCs to modify their lists of proposed 2025 GSEP projects, as necessary, to adapt to the revised GSEP revenue cap approved herein.

We are unpersuaded by the LDCs' arguments that reducing the revenue cap will extend the period when GSEP repairs are necessary. The Department recognizes that if the

LDCs continue with business as usual and focus solely on replacing leak-prone pipe, the GSEP target end day may be extended. See, e.g., D.P.U. 24-GSEP-04, Exhs. DPU 2-11; DPU 2-12. As noted throughout this Order, the Department is requiring reforms to the GSEP process that will preclude the LDCs from continuing with business as usual. Further, the Legislature provided the Department with discretion to extend the timeline beyond 20 years. Section 145(c). Section 145(c) specifically authorizes the Department to set a “reasonable target end date considering the allowable recovery cap.” For the reasons stated in the succeeding sections, the Department expects that with reforms in the risk prioritization process and increased integration of NPAs and advanced leak repair technology into the GSEP process, the target end day will not need to be extended, nor will it require \$13.7 billion in additional GSEP spending to remediate the remaining 4,049 miles of GSEP-eligible pipe.

3. Elimination of Carrying Charges on GSEP Deferrals

Since the beginning of GSEP, the Department, in approving the LDCs’ tariffs, has permitted the recovery of carrying charges on deferred amounts that exceed the cap. See, e.g., The Berkshire Gas Company, D.P.U. 14-131, Stamp-Approved GSEP Adjustment Clause at § 6.1 (November 4, 2015). In GSEP Orders, the Department has not explicitly addressed the appropriateness of accruing carrying charges on deferred amounts above the GSEP cap. See, e.g., D.P.U. 14-130; D.P.U. 21-GSEP-04. Thus, the Department has no formalized policy on this issue, but rather the practice has simply developed without any discussion. Given our obligation to ensure that the GSEP plans operate in a balanced manner

pursuant to the 2024 Climate Act, § 81, we address the appropriateness of the LDCs continuing to accrue carrying charges on newly deferred revenue requirements and enunciate a specific policy in the context of providing an incentive for cost containment.

The LDCs contend that the Department is not authorized to reject carrying charges because Section 145(c) allows the recovery of prudent costs and carrying charges represent an element of the costs an LDC incurs in connection with GSEP projects (LDCs Reply Brief at 71). The LDCs contend that the Legislature intended to have the LDCs recover carrying charges based on the plain meaning of the term “costs” (LDCs Reply Brief at 71 n.43 (citing to a dictionary definition of the term “costs”)). We reject that interpretation. This argument is inconsistent with the principles of statutory interpretation, which require that statutes be read as a whole to ascertain legislative intent. Commonwealth v. Morgan, 476 Mass. 768, 778 (2017); Commonwealth v. Williamson, 462 Mass. 676, 681 (2012). When the Legislature uses different language in different paragraphs of the same statute, it intends different meanings. Williamson, 462 Mass. at 682. Applying these principles of statutory interpretation, we need not turn to an asserted plain meaning of the term “costs” to ascertain whether the Legislature authorized carrying charges in for deferred costs under Section 145(d). Rather, reading Section 145 as a whole, it is clear from the statute that the Legislature recognizes the concept of carrying charges, as it made specific reference to them in including a “return associated with the plan” in Section 145(d) and “appropriate carrying charges” in Section 145(g) in connection with any subsequent disallowances of spending

within the cap.²⁰ The Legislature did not include any reference to “carrying charges” in connection with authorizing deferrals under Section 145(d). Therefore, we conclude that the recovery of carrying charges is entirely within the discretion of the Department.

The Attorney General, CLF, and the Sierra Club urge the Department to deny the LDCs recovery of carrying charges for any deferred amounts above the cap, arguing that this practice undermines the revenue cap as meaningful control on GSEP spending (Attorney General Brief at 35-36; Attorney General Reply Brief at 17-18; Sierra Club Brief at 20; CLF/Sierra Club Reply Brief at 7). Taken as a whole, the LDCs have accrued millions of dollars of interest tied to deferrals since the Gas Leaks Act was enacted in 2014. See, e.g., D.P.U. 22-GSEP-03, at 2, 15-16; D.P.U. 22-GSEP-06, at 1; D.P.U. 23-GSEP-01, at 10-11; D.P.U. 23-GSEP-04, at 10.

The Department, in its discretion, may allow any revenue requirements above the cap to be deferred. Section 145(f) provides that “[a]ny revenue requirement approved by the department in excess of such cap *may* be deferred for recovery in the following year” (emphasis added). There is nothing in the GSEP statute that suggests LDCs are entitled to recover carrying charges on any deferred amounts that the Department may authorize. Moreover, according to ratemaking principles, granting a deferral does not necessarily signify that a company will be made whole for deferred costs. Fitchburg Gas and Electric

²⁰ The reference to “appropriate carrying charges” in Section 145(g) is irrelevant to the issue of carrying charges on deferrals, as Section 145(g) applies to spending within the cap that is subsequently disallowed (*i.e.*, for any amounts that are disallowed, the LDC would also have to refund the carrying charges associated with those amounts).

Light Company, D.P.U. 13-90, at 151-152 (2014). Additionally, allowing carrying charges on a deferral pending its ultimate ratemaking treatment (i.e., recovery through future GSEAFs or base distribution rates) incentivizes a company to spend in excess of the revenue cap in anticipation of being made whole in future years, thereby weakening the incentive to control costs. D.P.U. 13-90, at 151. Insufficient incentives to control costs have led some of the LDCs²¹ spending at levels that exceed the revenue cap even after it was raised in 2019. See, e.g., D.P.U. 23-GSEP-04, at 10; D.P.U. 22-GSEP-06, at 10. Continuing to allow carrying charges on deferred GSEP expenditures would substantially weaken the incentive to control costs, instead encouraging continued spending at current and projected levels. That result would run counter to the urgent need to effect significant reform in the GSEP process. Eliminating carrying charges on deferrals going forward provides a very effective cost-containment incentive for the LDCs to begin to align their GSEP spending with lower revenue caps going forward. Therefore, beginning with the 2025 GSEPs, the LDCs will no longer be allowed to recover carrying charges on amounts deferred in excess of the revenue cap.

To be clear, the Department is not departing from our current practice of authorizing deferrals of GSEP spending in excess of the revenue cap. Nor are we departing from our current practice of requiring that any amounts deferred be subject to a prudence review in a

²¹ Since the enactment of the Gas Leaks Act, Berkshire Gas is the only LDC that has never exceeded the GSEP cap. See, e.g., D.P.U. 23-GSEP-02, at 1; D.P.U. 18-GSEP-02, at 7-8.

subsequent GREC proceeding before any such costs may be recovered in rates. As discussed below, that prudence review includes a requirement that the LDCs demonstrate their evaluation of alternatives to replacement of leak-prone pipe, such as the advanced repair technology that was added to Section 145(a) in the 2022 Clean Energy Act. We are discontinuing only the recovery of carrying charges on such deferred amounts. Further, we continue to allow recovery of carrying charges on any current deferral balances accrued by the LDCs prior to the change in policy we announce here. Accordingly, we direct the LDCs to submit within five business days a compliance filing revising their LDAC tariffs to eliminate the recovery of carrying charges on amounts deferred in 2025.

Additionally, we note that the GSEP statute does nothing more than provide a rate recovery mechanism for the LDCs to recover in a more expeditious manner the costs associated with remediating leak-prone pipe. Regardless of the level of the revenue cap, and whether the Department allows deferrals of amounts above the revenue cap or carrying charges on such deferrals, the LDCs are obligated to spend whatever it takes to maintain and operate a safe gas distribution system, in compliance with all Federal safety requirements. See, e.g., D.P.U. 24-GSEP-04, Exh. DPU 2-6, Att.; see also 49 C.F.R. § 192.00. We observe that the LDCs previously complied with such requirements under a 1.5 percent cap prior to 2019. Operating under the revised GSEP revenue cap, and without the benefit of recovering carrying charges on deferred amounts, will in no way compromise the safety and reliability of the gas distribution system in the Commonwealth.

4. Using GSEPs for NPAs

Sierra Club asserts that the Department should consider an exception to the 1.5 percent cap for repairs, NPAs, and retirements, allowing recovery up to 3.0 percent for the costs associated with these categories of measures (Sierra Club Brief at 20). The LDCs routinely include repairs and retirements in the GRECs filed annually on May 1, and it may be administratively burdensome to apply a different cap to such costs. With respect to NPAs, however, the Department finds that it is appropriate, and consistent with our obligation under the 2024 amendment to the GSEP statute to achieve GHG emissions reductions to comply with the Chapter 21N limits and sublimits and to minimize the potential for stranded costs, to create a bifurcated cap to enable spending on NPAs, over and above the newly established 2.5 percent revenue cap up to the previous 3.0 percent cap. While time is short for the LDCs to modify their 2025 GSEP project lists to accommodate NPA projects, going forward, as the revenue cap will likely continue to decline, it will be increasingly important for the LDCs to modify their GSEPs to devote more attention to consideration of NPAs. That strategy is consistent with the direction we enunciated in D.P.U. 20-80-B and D.P.U. 20-80-C, and to a limited extent puts NPAs on a level playing field with traditional GSEP projects in terms of financial attractiveness for LDCs, while avoiding additional investment in fossil fuel infrastructure.

D. Conclusion

While National Grid has no deferral over the 3.0 percent revenue cap, the Department will allow deferral of costs in excess of a 2.5-percent revenue cap. This allowance is

consistent with Section 145(f), which provides, in part, that “any revenue requirement approved by the [D]epartment in excess of such cap may be deferred for recovery in the following year.” As such, National Grid may defer the under-recovery balance for recovery under the GSEP in future years (consistent with the then applicable revenue cap) or in the Company’s next base distribution rate case. The Company may not recover carrying charges on GSEP costs incurred in 2025 and deferred for future recovery.

V. OTHER GSEP REQUIREMENTS

A. Eligible Infrastructure

1. Introduction

Section 145(a) defines an eligible infrastructure measure as a replacement, retirement, or an improvement of existing infrastructure of a gas company that: (i) is made on or after January 1, 2015; (ii) is designed to improve public safety or infrastructure reliability; (iii) does not increase the revenue of a gas company by connecting an improvement for a principal purpose of serving new customers; (iv) reduces, or has the potential to reduce, LAUF natural gas through a reduction in natural gas system leaks; (v) is not included in the current rate base of the gas company as determined in the gas company’s most recent rate proceeding; (vi) may include use of advanced leak repair technology approved by the department to repair an existing leak-prone gas pipe to extend the useful life of such gas pipe by no less than ten years; and (vii) may include replacing gas infrastructure with utility-scale non-emitting renewable thermal energy infrastructure. In reviewing the proposed GSEP, the Department must determine whether the projects comply with that statutory definition.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the GSEP, in its current form, encourages the LDCs to make unnecessary and costly investments in new gas infrastructure that conflict with climate-focused legislative and regulatory developments (Attorney General Brief at 5-10; Attorney General Reply Brief at 3). The Attorney General maintains that the LDCs seem to suggest that the GSEP statute grants them the authority to replace all leak-prone pipe with new pipe regardless of the cost to ratepayers and without consideration that the pipe may become stranded before the end of its useful life (Attorney General Brief at 20, citing Exh. LDC-Rebuttal-1, at 17). The Attorney General contends that this view is inconsistent with the statutory and regulatory changes that require LDCs to consider less costly means of leak-prone pipe remediation (Attorney General Reply Brief at 20). The Attorney General recommends that going forward, the Department require that, in addition to replacement of the leakiest pipe, the LDCs' GSEPs include decommissioning and implementation of NPAs, targeted decommissioning of non-essential and redundant pipe, repair, and advanced leak monitoring (Attorney General Brief at 20). In addition, the Attorney General argues that the LDCs' proposed GSEPs do not sufficiently reduce GHG emissions to levels to comply with limits and sublimits set forth in Chapter 21N pursuant to Section 145(b) as amended by the 2024 Climate Act (Attorney General Brief at 9-11).

b. CLF and Sierra Club

CLF contends that Massachusetts has identified electrification as the most cost-effective method to achieve its climate mandates and that it is well settled that ramping down the sale and consumption of fossil fuels is a major part of eliminating GHG emissions (CLF Brief at 6). CLF argues that the LDCs' current GSEP filings reflect a "business-as-usual" approach that will be insufficient to achieve Massachusetts' climate policy aims, instead committing large sums of money into fossil fuel infrastructure without providing demonstrable emissions benefits (CLF Brief at 6).

Sierra Club asserts that recent legislative changes to Section 145 demonstrate an intent on the part of the Legislature to fundamentally alter the GSEP mechanism (Sierra Club Brief at 6, citing 2024 Climate Act). Sierra Club cites the removal of references to "replacement" as indicative of the shift in focus of the GSEP away from pipeline replacement (Sierra Club Brief at 6-7). The Sierra Club also notes that the Legislature added "retirement" to the definition of "eligible infrastructure measure" (Sierra Club Brief at 7).

In addition, Sierra Club argues that the changed statutory and regulatory landscape shows that a wholesale pipeline replacement program is no longer the statutory GSEP mandate (Sierra Club Brief at 8). Sierra Club maintains that the Massachusetts Clean Energy and Climate Plan for 2025 and 2030 explicitly urges the LDCs to prioritize lower-cost repairs over replacements of leak-prone pipe (Sierra Club Brief at 9, citing D.P.U. 24-GSEP-03, Exh. SC-MF-1, at 18-19). CLF and Sierra Club contend that repair can successfully reduce risks and extend the life of an existing gas pipe until the pipe is able to be decommissioned

and replaced with lower GHG alternatives (CLF/Sierra Club Reply Brief at 5, citing D.P.U. 24-GSEP-03, Exh. SC-MF-1, at 50; Sierra Club Brief at 17, citing D.P.U. 24-GSEP-06, Exhs. SC-MF-1 at 19-21, 57; AG-DL-DM-Surrebuttal at 11). CLF and Sierra Club argue that the LDCs' GSEP investments have not uniformly resulted in a decrease in LAUF natural gas (CLF/Sierra Club Reply Brief at 2-3; Sierra Club Brief at 13).²²

c. Unions

The Unions claim that proposed changes to the GSEP due to environmental and ratepayer cost concerns would pose a challenge to the safety and reliability of aged natural gas infrastructure (Unions Brief at 2, citing Exh. LDC-Rebuttal-1, at 23). Specifically, the Unions argue that current natural gas infrastructure has high percentages of leak-prone pipe that should be replaced rather than repaired due to safety risks (Unions Brief at 2-3, citing Exhs. LDC-Rebuttal-1, at 9-10; EGMA-RJB, at 22; LU-KMJ-1, at 7-8; Tr. at 126-128,181-182). The Unions also argue that repairs can only eliminate active leaks but do not remove the need to replace the leak-prone pipe that may develop new leaks after it gets repaired (Unions Brief at 3, citing Exh. LDC-Rebuttal-1, at 26-28). The Unions assert that aging, leak-prone pipe is even more prone to break during winter months and replacement work during that time is far more difficult and dangerous (Unions Brief at 3,

²² Sierra Club points to LAUF percentages increasing for both National Grid and NSTAR Gas between 2019 and 2023 (Sierra Club Brief at 14, citing D.P.U. 24-GSEP-03, Exh. AG 1-8; D.P.U. 24-GSEP-06, Exh. AG 1-8).

citing Tr. at 181-182). The Unions maintain that a breakage during the winter months could leave consumers without a heating source for a prolonged period and increase ratepayer costs due to the nature of the work performed (Unions Brief at 3, citing Tr. at 181-182).

d. Company

The LDCs maintain that recent amendments to Section 145 do not alter the fundamental purpose of the GSEP or the Legislature's directives concerning leak-prone pipe (LDCs Reply Brief at 18). Acknowledging Massachusetts' broader policy push toward an energy transition, the LDCs emphasize their ongoing efforts to balance the safe and reliable delivery of gas service with its responsibilities in that transition (LDCs Reply Brief at 20). The LDCs maintain that none of the statutes or policies advancing decarbonization suggest that reducing system emissions should take precedence over their obligation to ensure safety and reliability (LDCs Reply Brief at 20–21). In addition, the LDCs assert that Section 145 does not prohibit leak-prone pipe replacement, and thus, conditioning cost-recovery on not replacing leak-prone pipe should be rejected (LDCs Reply Brief at 80).

The LDCs contend that the Attorney General ignores the fact that repairing leak-prone pipe has the potential to mitigate leaks, but it does not eliminate safety risks because as long as the leak-prone pipe is in the ground, it continues to deteriorate exponentially, i.e., the breakdown of the materials does not happen consistently over time, but rather accelerates once the process starts occurring (LDCs Reply Brief at 64, citing Exh. LDC-Rebuttal-1, at 11; Tr. 1, at 124, 132, 135-136). The LDCs also argue that repairing leak-prone pipe does not support the fundamental purpose of the GSEP, i.e., to reduce leak-prone pipe on

their systems through targeted and systematic removal and replacement (LDCs Reply Brief at 64, citing Exh. LDC-Rebuttal-1, at 11). The LDCs also assert that repairs are considered where appropriate and aligned with their duty to maintain safe and reliable service (LDCs Reply Brief at 27).

NSTAR Gas and National Grid argue that Sierra Club's conclusions and recommendations are based on the mistaken belief that recent amendments to Section 145 have subordinated the LDCs' obligation to provide safe, reliable service to customers to the achievement of the Commonwealth's climate goals (LDCs Reply Brief at 35). Specifically, NSTAR Gas and National Grid disagree with Sierra Club's arguments that the 2024 Clean Energy Act carefully and methodically changed Section 145 to remove all references to pipeline replacement and that this thorough removal of the term replacement and the substitution of the term "measure" or "remediation" evinces a clear intent on the part of the Legislature to shift the focus of the GSEP program away from pipeline replacement (LDCs Reply Brief at 35, citing Sierra Club Initial Brief at 6-7). NSTAR Gas and National Grid dispute Sierra Club's first claim that the 2024 Clean Energy Act did not "remove all references to pipeline replacement," noting that the list of measures included under the phase "eligible infrastructure measure" in Section 145 includes retirement (LDCs Reply Brief at 35). Next, NSTAR Gas and National Grid argue that there is no reasonable interpretation of the term "remediation" that would lead to the conclusion that replacement of leak-prone pipe is prohibited under Section 145 (LDCs Reply Brief at 36). In sum, NSTAR and National Grid reject Sierra Club's reinterpretation of Section 145, arguing that the

Legislature did not prohibit NSTAR Gas or National Grid from replacing leak-prone pipe consistent with their DIMPs (LDCs Reply Brief at 36).

NSTAR Gas and National Grid state that, consistent with PHMSA's regulations, they have identified the risks that leak-prone pipes pose to their distribution systems and have developed mitigation plans under their DIMPs (LDCs Reply Brief at 37-40). NSTAR Gas and National Grid reject the view that the amendments to Section 145 essentially prohibited the companies from implementing their DIMPs and replacing leak-prone pipe through the GSEP. More broadly, NSTAR Gas and National Grid assert that the recommendations made by Sierra Club, Attorney General, and CLF will impede the pursuit of the Commonwealth's climate goals (LDCs Reply Brief at 40).

3. Analysis and Findings

National Grid states that its planned projects are limited to the replacement or repair of mains, services, meter sets, and other ancillary facilities composed of non-cathodically protected steel, cast iron, wrought iron, and pre-1985 Aldyl-A plastic (Exhs. NG-GPP-2, at 3, 11, 15-18; NG-GPP-4; NG-GPP-5). The Company included two projects that use CISBOT systems in its 2025 GSEP as an advanced leak repair technology consistent with the 2022 Clean Energy Act and its LDAC tariff (Exhs. NG-GPP-2, at 4-6, 43; NG-GPP-8; NG-GPP-6; NG-GPP-7; SC 2-6). We find that National Grid provided sufficient documentation to show the planned replacements or repairs for 2025 are consistent with the requirements of Section 145(a) (Exhs. NG-GPP-4; NG-GPP-5; DPU 1-8; DPU 1-9 & Att.; DPU 1-10; DPU 2-6; SC 1-2 & Att.; SC 1-3; SC 3-1; SC 3-2; SC 3-3 & Att.; SC 3-4;

SC 3-5; SC 4-1 & Att.). Nonetheless, there was minimal inclusion of repairs or other remediations short of replacing pipe that would demonstrate the Company is foregoing business as usual (DPU 1-1; DPU 1-6; DPU 2-1). Further, the Company has not provided sufficient documentation to demonstrate that alternatives to full replacement were evaluated (DPU 1-8; DPU 1-9 & Att.; DPU 2-6). The Legislative changes to Section 145 require such evaluations as a necessary component of the GSEP. 2024 Climate Act, § 81.

Further, the evidence in these proceedings fails to demonstrate that the LDCs, including National Grid, rigorously evaluated alternatives to replacement of leak-prone pipe, such as the advanced repair technology that was added to Section 145(a) in the 2022 Clean Energy Act (Exhs. NG-GPP-1, at 20-22; NG-GPP-2, at 24-25, 27-28). See, e.g., D.P.U. 24-GSEP-06, Exhs. ES-RJB-1, at 24-25, 40-42; ES-RJB-1, App. A; D.P.U. 24-GSEP-01, Exhs. Unitil-RKCL-1, at 33; Unitil-RKCL-6. While the LDCs' filings acknowledge repair and relining as alternatives, their treatment is cursory and inadequate (Exh. NG-GPP-2, at 27-28). See, e.g., D.P.U. 24-GSEP-06, Exhs. ES-RJB-1, at 24-25, 40-42; ES-RJB-1, App. A; D.P.U. 24-GSEP-01, Exhs. Unitil-RKCL-1, at 33; Unitil-RKCL-6. Repair is routinely dismissed on the grounds that it only delays eventual replacement, an argument that presumes the existing natural gas distribution will operate in perpetuity, an assumption that we rejected earlier in this Order as being inconsistent with the requirement that potential exposure to stranded costs be minimized and the Department's obligation to achieve GHG emissions reductions in accordance with the limits and sublimits established in Chapter 21N. (Exh. LDC-Rebuttal-1, at 26-28). See Section IV. above.

Although National Grid included two CISBOT projects, the Company did not demonstrate that relining and other advanced leak repair technology were seriously considered or applied to other specific segments of leak-prone pipe (Exhs. NG-GPP-2, at 27-28; SC 2-5; SC 2-6). This failure undermines the statutory directive and the Department's ability both to determine whether costs are prudently incurred and to assess whether the remediation pathway selected by the LDC represents a reasonable, affordable solution for customers.

Beginning with the 2026 GSEPs to be filed by October 31, 2025, the Department will require that, in addition to the existing evaluation of NPAs required by 20-80-C as discussed in Section VII. below, each proposed GSEP project subject to cost recovery must include documentation showing that the feasibility of advanced leak repair and relining methods has been considered as a means of reducing leaks and extending the useful life of the asset. The documentation should enable the Department to evaluate whether:

- The LDC has assessed whether repair or lining is technically feasible for the type and condition of pipeline at issue;
- The most likely failure modes for the segment (e.g., joint leaks vs. wall deterioration) have been identified and matched with appropriate remediation methods;
- The proposed intervention reflects a reasonable consideration of lifecycle costs and expected asset life;
- The segment is located in an area with a potential for decommissioning in the near future, and how that has been factored into the proposed intervention; and

- The rationale for choosing full replacement is clearly supported, where alternatives appear viable.

The Department does not intend to prescribe a specific methodology for remediating leak-prone pipe but, consistent with its obligation to ensure that the GSEPs operate in a balanced manner to maintain affordable rates for customers, the Department must have a basis for evaluating whether the record demonstrates meaningful and project-specific consideration of eligible alternatives consistent with Section 145(d).

We find that the Company's proposed projects are consistent with the other statutory criteria defining eligible infrastructure. The proposed projects are for calendar year 2025 and thus are made on or after January 1, 2015 (Exhs. NG-GPP-1 at 29-30; NG-GPP-4; NG-GPP-5). Additionally, the replacement or repair of the designated leak-prone pipe achieves the goals of improvements in public safety, environmental impact of GHG emissions, infrastructure reliability, and the reduction of LAUF natural gas (Exhs. NG-GPP-2, at 29, 31, 35; AG 1-8, AG 1-9 & Att., AG 1-10, AG 2-1 & Att., AG 2-2, AG 2-3 & Att., AG 2-4).²³ Further, the Company has limited these projects to the replacement or repair of existing leak-prone pipe and will therefore not be increasing its revenue by connecting new customers (Exhs. NG-GPP-4; NG-GPP-5; DPU 1-8; DPU 1-9 & Att.; DPU 1-10; DPU 2-6; SC 1-2 & Att.; SC 1-3; SC 3-1; SC 3-2; SC 3-3 & Att.; SC 3-4;

²³ While there has been fluctuation in LAUF natural gas levels, overall National Grid has remained proactive in eliminating gas leaks with the GSEP in place (Exhs. NG-GPP-1 at 13-14,18; AG 1-8).

SC 3-5; SC 4-1 & Att.). Finally, the Company's last base distribution rate case included GSEP investments through December 31, 2019. Boston Gas Company, D.P.U. 20-120, at 157-160 (2021). As such, the projects proposed in this filing are not included in the Company's rate base.

B. Coordination with Distribution Pipeline Integrity Management Plan

1. Introduction

National Grid's strategy for managing leak-prone pipe is outlined in its DIMP, which was last revised in November 2023 (Exhs. NG-GPP-2, at 23-24; NG-GPP-3). Pursuant to the DIMP, the Company prioritizes the replacement of distribution piping using leak history, type of leak, pipe material, surrounding geography, segment length, nearby construction activity, field conditions, customer issues, open leaks, engineering judgment, and ability to collaborate with municipal projects (Exhs. NG-GPP-2, at 22-23; NG-GPP-3).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the LDCs' administration of the GSEP is inconsistent with the requirements in 49 C.F.R. §§ 192.1001 through 192.101 (Attorney General Brief at 29). The Attorney General argues that the LDCs mischaracterize the federal regulations as requiring the replacement of all leak-prone pipe with new pipe, when the regulations require the LDCs to develop plans to mitigate risks on the gas distribution system but does not dictate how leak-prone pipe should be remediated (Attorney General Brief at 29; Attorney General Reply Brief at 4-6). The Attorney General argues that the LDCs'

replacement of approved GSEP projects with projects that align with municipal paving schedules is inconsistent with the “worst first” obligation in the DIMPs (Attorney General Brief at 32, citing Section 145(c)).

b. Company

National Grid proposes to continue prioritizing leak-prone pipe replacement recovered through the GSEP in accordance with its DIMP (Company Brief at 34). The Company states that, consistent with the DIMP, it prioritizes leak-prone pip main segments for replacement based on consideration of, among other things, leak repair history, type of leaks, pipe material, surrounding geography, segment length, nearby construction, field conditions, customer issues, open leaks, and engineering judgment (Company Brief at 34, citing Exh. NG-GPP-2, at 22). The Company states that it continuously monitors system performance to identify any potential leak-prone pipe with integrity issues (Company Brief at 36, citing Exh. NG-GPP-2, at 24).

The LDCs refute the Attorney General’s claim that the LDCs are managing their GSEPs in a manner that is not consistent with the DIMP’s “worst-first” requirement because they select paving projects for inclusion in the GSEP (LDCs Reply Brief at 65). The LDCs argue that the act of paving and the properties of new pavement represent a risk to leak-prone pipe, and that municipal paving projects add to the risk score for a pipe segment, thereby elevating an otherwise lower risk segment of pipe to a higher risk score (LDCs Reply Brief at 65). The LDCs maintain that concentrating the GSEP solely on high-risk facilities and not considering the increased risk created by paving projects would result in fewer completed

replacements and therefore a higher risk system, which would be contrary to the LDCs' DIMP (LDCs Reply Brief at 65, citing D.P.U. 24-GSEP-03, Exhs. NG-GPP-2, at 25-26, AG 1-2; D.P.U. 24-GSEP-06, Exhs. ES-RJB-1, at 27; DPU 1-8). In addition, the LDCs maintain that the Attorney General raised a similar argument in the initial GSEP proceedings, and the Department found that the DIMP does not require LDCs to prioritize leak-prone pipe replacements in order of worst-first, and that LDCs must consider a wide variety of factors in selecting the appropriate projects (LDCs Reply Brief at 65, citing D.P.U. 14-135, at 19-20, 25; D.P.U. 14-132, at 25). Further, the LDCs maintain that under their DIMPs, they rely on a number of tools and processes to identify, rank, and mitigate or eliminate risk, and they have not suggested that GSEP is required by their DIMPs, as the Attorney General implies; rather, they treat the GSEP as one of those tools (LDCs Reply Brief at 64-65, citing Tr. 1, at 126).

3. Analysis and Findings

Pursuant to federal regulations, the U.S. Department of Transportation's PHMSA and the Department's Pipeline Safety Division ensure the LDCs' compliance with the DIMP (see Exh. NG-GPP-2, at 24). See also 49 C.F.R. §§ 191.11, 192.1007(g). The DIMP aims to enhance safety by identifying and reducing gas distribution pipeline integrity risks (Exh. NG-GPP-2, at 22-23). Section 145(c) requires the Company's GSEP to prioritize implementation of the DIMP, especially the requirements specified in 49 C.F.R. §§ 192.1001 through 192.1015.

The current GSEPs do not appear to be “narrowly tailored to addressing leak-prone infrastructure most immediately in need of remediation.” Section 145(d). While the LDCs maintain that their proposed 2025 GSEP projects are informed by risk scores developed under their DIMPs, their filings do not consistently demonstrate how risks are quantified, compared, or used to prioritize project selection—or how substitutions and mitigation alternatives are evaluated and justified. See, e.g., D.P.U. 24-GSEP-06, Exhs. ES-RJB-1, at 35-38; ES-RJB-1, App. A; D.P.U. 24-GSEP-01, Exhs. Unitil-RKCL-1, at 22-27; Unitil-RKCL-5. In several cases, projects appear to have been substituted due to municipal coordination needs, without clear evidence that the substitute projects address comparable or greater risk. See, e.g., D.P.U. 24-GSEP-06, Exhs. ES-RJB-1, at 35-38; ES-RJB-1, App. A; D.P.U. 24-GSEP-01, Exhs. Unitil-RKCL-1, at 22-27; Unitil-RKCL-5.²⁴ Rather than being narrowly tailored, the development of GSEP project lists seem to be geared toward assembling, in an unsystematic manner, a sufficient number of projects to achieve a level of spending at or above the current 3.0 percent revenue cap. The risk-prioritization process must be more rigorous to ensure the continued safety of the gas distribution system while protecting ratepayers against excessive spending at and above the revenue cap.

²⁴ The Attorney General asserts that LDCs frequently depart from approved GSEPs by deferring multiple projects and adding other projects that were not included in their approved GSEPs (Attorney General Brief at 25). The Department previously directed the LDCs to provide further evidence to demonstrate it appropriately substituted new projects for Department-approved projects in the GREC filings due May 1, 2025. See, e.g., D.P.U. 24-GREC-04, at 32.

To facilitate development of a more comprehensive risk-prioritization strategy, the Department's Pipeline Safety Division will convene a GSEP Risk Assessment Working Group to improve the transparency and consistency of risk prioritization within GSEP filings. In addition to the Pipeline Safety Division, we anticipate that the GSEP Risk Assessment Working Group will include interested parties such as the Attorney General, LDC representatives, and independent experts deemed qualified by the Pipeline Safety Division. Under the direction of our Pipeline Safety Division, the GSEP Risk Assessment Working Group will convene technical sessions over the next few months to develop proposed risk-based prioritization principles that will guide the 2025 GSEP filings this fall. We anticipate that the Department will adopt these risk-based principles through an appropriate Department order or hearing officer memorandum by September 15, 2025. The GSEP Risk Assessment Working Group should develop a risk-based prioritization process that includes the following:

- Clarifies and provides guidance on the federal DIMP rule as it relates to addressing leaks from the gas distribution system, and establishes the relationship between (a) DIMP risk analysis and scoring indexes, and (b) GSEP risk prioritization and risk scoring;
- Establishes an improved and systematic process for reviewing and approving LDC plans for capital and non-capital investments that remediate the riskiest segments of the gas system, including pipeline replacement, NPAs, and decarbonization demonstration projects;

- Creates specific parameters for the LDCs' GREC proceedings to apply to LDC decisions that depart from Department-approved GSEP projects, including evidence that the new project did not displace an approved project with a higher risk-prioritization factor;
- Explains how LDCs prioritize GSEP projects based on the risk to public safety and the environment;
- Shows how DIMP risk analysis and scoring indices inform GSEP risk prioritization and risk scoring;
- Documents the quantitative and qualitative factors considered (e.g., leak history, pipeline material and vintage, pressure class, proximity to high-risk populations or buildings);
- Provides transparent treatment of project substitutions, including evidence that the substitute project is of equal or greater risk;
- Includes a qualitative and quantitative assessment of best industry practice gas pipeline repair methods, identifying which repair techniques are most effective for specific pipe materials and configurations (e.g., small- vs. large-diameter cast iron), and distinguishing cases where such repairs can extend safe service life by ten years or more, in accordance with Section 145(a);
- Includes an evaluation of the technical viability and safety implications of cured-in-place lining ("CIPL") technologies for extending pipeline life beyond 10 years, including material suitability, installation conditions, and risk mitigation factors; and

- Demonstrates how GSEP investments contribute to measurable reductions in system risk over time.

As we have made clear, future GSEP filings must comply with a more rigorous risk-prioritization process to ensure compliance with the DIMP. For purposes of the 2024 GSEPs before us here, which the LDCs prepared pursuant to the Department's prior, less prescriptive directives and prior to 2024 Climate Act, the Department finds that they will implement the DIMP consistent with the requirements specified in 49 C.F.R. §§ 192.1001 through 192.1015

C. Accelerated Replacement

Under the 2025 GSEP, the Company anticipates completing the replacement of 113.4 miles of leak-prone mains and associated services in 2025 for the Boston Gas Division and 6.6 miles of leak-prone mains and associated services in 2025 for the Colonial Gas Division (Exhs. NG-GPP-4; NG-GPP-5; NG-GPP-8). The Company's completion date for the replacement of all GSEP-eligible pipe is 2039 for the Boston Gas Division and 2034 for the Colonial Gas Division (Exh. NG-GPP-2, at 18, 38). Over the next five years, the Company expects to replace an average of 66 miles of leak-prone mains per year for the Boston Gas Division and an average of 5 miles of leak-prone main per year for the Colonial Gas Division (Exh. NG-GPP-2, at 48). The Company states this plan is consistent with the recommendations of the Dynamic Risk Assessment Systems, Inc. ("Dynamic Risk") Report and aligns with the goal of increasing annual cast iron replacements by ten percent by calendar year 2026 as compared with calendar year 2020 (Exh. NG-GPP-2, at 38). See also

Statewide Assessment of Gas Pipeline Safety: Commonwealth of Massachusetts by Dynamic Risk Assessment Systems, Inc., at 38 (January 29, 2020).²⁵ The Company states that this plan will reduce new leaks discovered each year and maintain appropriate focus on risk reduction (Exh. NG-GPP-2, at 38).

The Department finds that National Grid's proposed pace of replacement for 2025 complies with the legislative purpose of the GSEP statute by advancing the removal and replacement of leak-prone pipe from the Massachusetts gas distribution system on an accelerated basis. Section 145(c). The Department previously found that the GSEP is intended to accelerate the replacement of leak-prone pipe, and that in the absence of the GSEP, aging infrastructure would be retired and replaced in due course. Boston Gas Company, D.P.U. 20-GSEP-03, at 13-14 (2021). Based on the foregoing, we find that National Grid's 2025 GSEP accomplishes continued accelerated replacement of leak-prone infrastructure consistent with the requirements of Section 145(c).

National Grid provided interim target goals in accordance with Section 145(b), demonstrating that it is meeting the appropriate pace to reduce the leak rate on its natural gas infrastructure and to replace its leak-prone natural gas infrastructure in a safe and timely manner (Exh. NG-GPP-2, at 4). Specifically, the Company provided interim targets for infrastructure replacement over the next six years in compliance with Section 145(b)

²⁵ The Department retained Dynamic Risk to perform an independent statewide assessment of pipeline safety in Massachusetts, and Dynamic Risk issued its report in early 2020.

(Exhs. NG-GPP-1, at 30-31; NG-GPP-2, at 4, 16-18). These interim goals have been determined based on the Company's DIMP and implemented utilizing the Company's procedure to prioritize replacement of leak-prone pipe, while maintaining the pace of pipe replacements (Exhs. NG-GPP-2, at 22-23; NG-GPP-3). The Department finds that the Company has adequately fulfilled the requirements of Section 145(b).

D. Customer Costs and Benefits

1. Introduction

National Grid states that its GSEP costs are the sum of labor costs, materials, contractor charges, road surface restoration, traffic control, and permitting costs (Exh. NG-GPP-2, at 30-36). The Company states that other costs that affect the GSEP schedule reflect elements outside of National Grid's control, such as field conditions, customer issues, and emergencies (Exh. NG-GPP-2, at 45-46).

National Grid states that it has structured its GSEP to achieve a significant reduction in aggregate leak rates over the life of the program, which will represent a substantial improvement in public safety and service reliability (Exh. NG-GPP-2, at 30). In addition, National Grid reports that methane is a principal component of natural gas, and the release of methane from a distribution system results primarily from leaking infrastructure (Exh. NG-GPP-2, at 31). The Company states that the GSEP will provide environmental benefits because replacing leak-prone pipe and repairing gas leaks will help prevent the release of natural gas into the atmosphere and will thus reduce methane emissions (Exh. NG-GPP-2, at 31-35). National Grid also states that its GSEP has resulted in the

creation of new jobs in Massachusetts and that it expects the GSEP will further increase construction work performed on the system, which in turn will create or preserve jobs (Exh. NG-GPP-2, at 35). Finally, National Grid states that the GSEP will reduce costs and inconveniences to municipalities (Exh. NG-GPP-2, at 36). Specifically, the Company states that when a leak occurs, the Company deploys its resources on an emergency basis to investigate the leak, and municipalities also deploy their resources, such as fire departments, police, and other public safety staff, to address potential public safety issues (Exh. NG-GPP-2, at 36). The Company states that these emergency requests result in costs and inconvenience to municipalities (Exh. NG-GPP-2, at 36). As a greater level of system replacement occurs, National Grid anticipates that these emergency costs and inconveniences will be reduced (Exh. NG-GPP-2, at 36).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the LDCs' proposed GSEP investments, many of which are pipeline replacements, will become stranded assets, reflecting spending that far exceeds prudent and reasonable investment in safety and system reliability (Attorney General Brief at 11-15). The Attorney General argues that the costs of these stranded assets will likely have a disproportionate impact on low- and moderate-income ratepayers who would remain on the gas system longer than customers who can pay the upfront costs of electrification (Attorney General Brief at 18-19). The Attorney General recommends that the Department define stranded assets for GSEPs and direct the LDCs to conduct a stranded asset

cost-benefit analysis (Attorney General Brief at 41-42; Attorney General Reply Brief at 18-19). Specifically, the Attorney General recommends defining stranded assets as “an asset that becomes unnecessary or redundant before the end of its nominal useful service life” (Attorney General Brief at 42). The Attorney General contends that this definition is consistent with the definition given by National Grid in its testimony (Attorney General Brief at 42, citing Tr. at 57-58). The Attorney General recommends that the Department direct the LDCs to provide for each GSEP project that includes replacement of leak-prone pipe with new pipe a stranded asset cost-benefit analysis that includes: (1) the estimated useful life of the pipe; (2) the likelihood that the pipe will become redundant or unnecessary to serve customer demand before the end of its useful life; and (3) the ratepayer costs associated with the GSEP replacement project and potential decommissioning once the asset becomes stranded (Attorney General Brief at 42).

b. CLF and Sierra Club

CLF contends that reducing the amount of potential stranded assets is critical to ensuring customers are not left footing the bill for energy infrastructure known to have a limited role in the Commonwealth’s energy future (CLF Brief at 10-11). CLF and Sierra Club argue that GSEP spending must be scaled down and its focus must shift away from wholesale replacement toward repair and NPAs to reduce stranded asset risk and harmonize with the Commonwealth’s climate laws and regulations (CLF/Sierra Club Reply Brief at 5, citing Attorney General Brief at 5-11, 19-20, CLF Brief at 6, 9, Sierra Club Brief at 16-19; Sierra Club Brief at 8, 16-17). Sierra Club contends that the 2025 GSEP filings make clear

that the LDCs have not departed from a business-as-usual approach to GSEP planning and spending (Sierra Club Brief at 10). CLF and Sierra Club maintain that this business-as-usual approach results in financial risk for ratepayers through stranded asset risk and does not result in a meaningful reduction in GHG emissions (CLF/Sierra Club Reply Brief at 2; Sierra Club Brief at 13-15). Sierra Club asserts that, per the amendments to Section 145, GSEPs must include “the costs of potential stranded assets and the benefits of avoiding financial exposure to such assets” (Sierra Club Brief at 8). Regarding the stranded asset risk for ratepayers, CLF and Sierra Club contend that as the Commonwealth reduces its reliance on gas and transitions towards electrification, GSEP investments are likely to become stranded assets, and that the costs of stranded assets will fall disproportionately on the remaining gas customers as customers leave the system (CLF & Sierra Club Reply Brief at 4, citing Attorney General Brief at 18-19; CLF Brief at 10; Sierra Club Brief at 15, citing Exh. AG-DL-DM-1, at 32, 35). Sierra Club argues that, given the pace of the LDCs’ GSEP expenditures from 2015 to 2025, the Department’s guidance to correct course is urgently needed to avoid stranded asset risk (Sierra Club Brief at 15-16, citing Exh. AG-DL-1, at 8).

c. Company

National Grid maintains that there are numerous benefits to accelerating the replacement of leak-prone pipe on its distribution system, including: (1) a reduction in leak rates; (2) the reduction of methane; (3) the creation of jobs stemming from the increased need for a qualified workforce; and (4) a decrease in municipal cost and inconvenience that will correlate with the decrease in the leak rate (Company Brief at 50, citing Exh. NG-GPP-2, at

30-36). National Grid argues that it has structured its GSEP to achieve a significant reduction in aggregate leak rates over the life of the program, which will represent a substantial improvement in public safety and service reliability (Company Brief at 51, citing Exh. NG-GPP-2, at 31). In addition, National Grid asserts that the replacement of leak-prone pipe reduces the impact of methane on the environment (Company Brief at 51, citing Exh. NG-GPP-2, at 31; AG 1-9).

National Grid also argues that the GSEP will reduce costs and inconveniences to municipalities (Company Brief at 53, citing Exh. NG-GPP-2, at 36). Specifically, National Grid explains that when a leak occurs, the Company deploys its resources on an emergency basis to investigate the leak, and municipalities also deploy their resources, such as fire departments, police, and other public safety staff, to address potential public safety issues (Company Brief at 52-53, citing Exh. NG-GPP-2, at 36). National Grid states that these emergency requests result in costs and inconvenience to municipalities and customers (Company Brief at 53, citing Exh. NG-GPP-2, at 36). As a greater level of system replacement occurs, National Grid anticipates that these emergency costs and inconveniences will be reduced (Company Brief at 53, citing Exh. NG-GPP-2, at 36). Finally, National Grid states that the GSEP will increase construction work performed on the system, which in turn will create or preserve jobs (Company Brief at 52, citing Exh. NG-GPP-2, at 35).

The LDCs take issue with the Attorney General's proposed definition of "stranded asset," as they argue it could encompass assets designed to provide system redundancy and to support safety or reliability of the system and ignores the relationship between depreciation

approaches and the potential for asset stranding (LDCs Reply Brief at 81, citing Attorney General Brief at 42). The LDCs claim that infrastructure upgrades such as leak-prone pipe replacement should not be deemed stranded assets when their function is essential to ensuring a safe and reliable system, especially given speculative projections of future asset utilization (LDCs Reply Brief at 82). The LDCs also oppose the Attorney General's recommended stranded asset cost-benefit analysis, which they contend ignores relevant considerations such as obligatory risk mitigation and required NPA analysis (LDCs Reply Brief at 82). In addition, the LDCs maintain that the issue of potential stranded assets is more appropriately addressed in the LDCs' CCPs than in the LDCs' GSEPs (LDCs Reply Brief at 82-83).

3. Analysis and Findings

Section 145(c) expressly calls for a company to include in its GSEP a description of customer costs and benefits under the plan. The 2024 Climate Act added the requirement that in considering customer costs and benefits, the LDCs include the costs of potential stranded assets and the benefits of avoiding financial exposure to such assets. Section 145(c). Because the Company's GSEP was filed prior to the issuance of the 2024 Climate Act, National Grid did not include any analysis regarding stranded assets in its GSEP. In discovery, the Company stated that, in coordination with the other LDCs, it had engaged an expert consultant to study the issue of potential stranded investments and would submit a report in the CCP docket (Exh. AG 1-10). The Company filed the consultant's report, including an LDC-specific analysis as part of its CCP on April 1, 2025. D.P.U. 25-41, Exh. NG-CCP, Att. 6. While the Department remains concerned with the potential amount

of stranded assets, we will not prejudge the adequacy of National Grid's report in this proceeding. Instead, the Department will fully investigate the issue of stranded costs in the CCP dockets.

VI. CONCLUSION ON THE 2025 GSEP

Based on the Department's review of the record in this proceeding, the Department finds that the Company's 2025 GSEP complies with the requirements set forth in Section 145 and G.L. c. 25, § 1A. Accordingly, the Department approves National Grid's 2025 GSEP.²⁶ In addition, the Department finds that the Company's resulting revenue requirements for both divisions are calculated in accordance with its LDAC tariff, are consistent with Department precedent, and result in just and reasonable rates. For the Boston Gas Division, as outlined in Section IV. above, the Department has reduced the revenue cap resulting in revised GSEAFs, which we find to be appropriate (Exh. DPU 3 1-2, at 1-2). For the Colonial Gas Division, proposed GSEAFs do not exceed the allowed 2.5 percent cap. The Department has reviewed the Company's proposed GSEAFs for the Colonial Gas Division and supporting schedules and finds them to be appropriate. Consistent with G.L. c. 25, § 1A, the Department's

²⁶ The Attorney General, CLF, and Sierra Club recommend that the Department direct the LDCs to integrate the GSEPs into the Climate Compliance Plans and other integrated energy planning ("IEP") efforts, which are discussed in D.P.U. 20-80-B (Attorney General Brief at 42-43; Attorney General Reply Brief at 19-20; CLF Brief at 9-10; CLF/Sierra Club Reply Brief at 8). For example, the Attorney General asserts that the IEP process should use the GSEPs to identify gas capital investments and their timing to inform the LDCs' selection of areas for electrification and decarbonization (Attorney General Brief at 43-44). To the extent that it is appropriate for the Department to direct the LDCs to integrate GSEPs into the CCP and IEP efforts, it will be done in the relevant dockets.

authority to regulate rates, and well-established precedent, the Department has reviewed customer bill impacts associated with the GSEAFs for the Boston Gas Division and the Colonial Gas Division and finds that they are within the range of what is reasonable under the circumstances and do not violate the goal of rate continuity.

Based on the foregoing, the Department approves, for the Boston Gas Division, a 2025 revenue requirement of \$203,002,671, along with the estimated costs to repair G3SEI leaks of \$1,148,708, with \$198,836,772 recovered through the GSEAFs for effect May 1, 2025 and the remaining \$5,314,607²⁷ deferred for recovery in the future (Exh. DPU 3 1-2, at 1-2). In addition, the Department approves, for the Colonial Gas Division, a 2025 revenue requirement of \$17,058,686, along with the estimated costs to repair G3SEI leaks of \$75,146, with \$17,133,832 recovered through the GSEAFs for effect May 1, 2025.²⁸

VII. NON-PIPELINE ALTERNATIVES

A. Introduction

The Department set forth future filing requirements regarding NPAs in last year's GSEP Orders. See, e.g., Boston Gas Company, D.P.U. 23-GSEP-03, at 22 (2024).

²⁷ The Department recognizes that the actual deferred amount may differ based on the directive concerning the accrual of carrying charges for GSEP projects completed in 2025 and beyond. See Section IV.C.3 above.

²⁸ Pursuant to Boston Gas Company, D.P.U. 24-OGAF-GRID, Hearing Officer Memorandum at 4 (February 27, 2024), National Grid is directed to submit, within five business days after issuance of this Order, an informational filing in the gas adjustment factor docket with updated local distribution adjustment factors that include these GSEAFs.

Specifically, consistent with the Commonwealth's climate targets, the Department directed the LDCs to demonstrate that they adequately considered NPAs and found them to be nonviable or cost prohibitive. See, e.g., D.P.U. 23-GSEP-03, at 22, citing [Investigation into Role of Local Gas Distribution Companies as Commonwealth Achieves Target 2050 Climate Goals](#), D.P.U. 20-80-B at 97-98 (2023); D.P.U. 20-80-C at 21-22. To obtain full recovery of its GSEP costs, each LDC must demonstrate the adequacy of its NPA analysis. See, e.g., D.P.U. 23-GSEP-03, at 22, citing D.P.U. 20-80-B at 97-98; D.P.U. 20-80-C at 21-22. The Department noted that our directives would not interfere with the mandates of the federal and state regulations intended to ensure the safe maintenance and operation of the natural gas pipeline system. D.P.U. 20-80-C at 21; D.P.U. 20-80-B at 97.

In the instant proceeding, National Grid provided documentation regarding its NPA analysis (Exhs. NG-GPP-2, at 24-25; DPU 1-8). Because the NPA analysis framework is under review by the Department in D.P.U. 25-41, the Company developed an interim NPA analysis (Exhs. NG-GPP-2, at 24-25; DPU 1-8). For its interim NPA analysis framework, the Company developed a three-step process (Exh. DPU 1-8). In step one of the interim NPA assessment National Grid will determine if the gas project is an NPA opportunity (Exh. DPU 1-8). In step two the Company will evaluate the viability of the project by conducting cost comparisons of NPA and gas options as well as gas system integrity and electric capacity analyses (Exh. DPU 1-8). If the project is viable for NPA implementation after additional analyses, it moves forward to NPA implementation (Exh. DPU 1-8).

National Grid states that the projects were all potential NPA projects but were cost prohibitive therefore the analyses were completed in step two (Exh. DPU 1-8; DPU 1-9 &Att.; DPU 2-6). Specifically, the Company explained that after the project was determined to be an NPA opportunity it compared the NPA cost estimate of the project versus the pipe replacement cost estimate, and if the NPA cost exceeded the cost of pipe replacement, the project was deemed as cost -prohibitive and continued as a gas solution (Tr. at 54).

The Company states that as the NPA process evolves and even when it is in place there will be some segments with high risk scores that will require replacement within a certain period and thus will not allow for NPA consideration in order to ensure system safety in accordance with its DIMP (Exh. NG-GPP-2, at 24-25). National Grid states that it will continue to use its prioritization procedures subject to modifications from the NPA stakeholder working group (Exh. NG-GPP-2, at 26)

In D.P.U. 20-80-B at 98 n.66, the Department directed the LDCs to file their proposed NPA analysis framework as part of the CCP, after consulting with stakeholders. See also D.P.U. 20-80-C at 27. The LDCs submitted their CCP, inclusive of their NPA analysis framework, on April 1, 2025, which were docketed as D.P.U. 25-40 through D.P.U. 25-45.

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the LDCs' NPA analysis framework is inadequate as the majority of GSEP projects were excluded from NPA consideration (Attorney General

Brief at 21, citing Exh. AG-DL-DM-1, at 23-26). The Attorney General asserts that the purpose of the NPA analysis is to prevent investment in new gas infrastructure that will likely be decommissioned or become redundant as the Commonwealth pursues its decarbonization goals (Attorney General Brief at 21). The Attorney General contends that an NPA with a higher initial cost than a gas pipeline replacement is a more prudent investment because the NPA will be in use longer than a pipeline replacement (Attorney General Brief at 22).

Acknowledging that the long-term NPA framework is subject to separate adjudication in D.P.U. 25-40 through D.P.U. 25-45, the Attorney General urges the Department to prohibit the LDCs from exempting the majority of GSEP projects from NPA analysis in subsequent GSEP proceedings (Attorney General Brief at 22). The Attorney General also argues that the Department should prohibit the LDCs from adding another pipeline replacement project as a substitute for a GSEP project selected for NPA purposes (Attorney General Brief at 22, citing Tr. at 60-61). In addition, the Attorney General contends that the Department should require the LDCs to perform targeted decommissioning analyses and to decommission leak-prone pipe that does not serve customers, has become redundant, and is not needed to maintain system reliability (Attorney General Brief at 22-23).

The Attorney General disagrees with the LDCs assertion that replacing leak-prone pipe with new pipe is the only way to reduce risk on the gas distribution system and therefore recommends that the Department require the LDCs to, when possible, repair pipe or conduct advance monitoring of leak-prone pipe to delay total pipe replacement while NPAs are implemented (Attorney General Brief at 23, citing Exh. LDC-Rebuttal-1, at 11;

Attorney General Reply Brief at 7-8). The Attorney General asserts that repairing and monitoring non-leaking, leak-prone pipe can extend the life of the pipe until it can be decommissioned after customers transition to alternative heating systems, which she maintains is the only way to eliminate risk from material failure (Attorney General Brief at 23, citing Exh. AG-DL-DM-Surrebuttal at 10-11; Attorney General Reply Brief at 11). The Attorney General argues that repairing and monitoring non-leaking, leak-prone pipe is more prudent than investing in new gas infrastructure, especially for segments with a lower prioritization factor (Attorney General Brief at 24).

2. CLF and Sierra Club

CLF and Sierra Club argue that the LDCs' NPA analyses fail to meaningfully consider alternatives to pipeline replacements as required by the Department's Orders in D.P.U. 20-80 (CLF Brief at 7; Sierra Club Brief at 10-11; CLF/Sierra Club Reply Brief at 4, 6). CLF and Sierra Club maintain, for example, that all but one of the projects in the NSTAR Gas GSEP failed the first step of the analysis because the exclusion criteria were essentially the same criteria that NSTAR Gas uses to prioritize projects for GSEP, meaning that projects will nearly always fail the initial screen if they are risky enough to be prioritized for inclusion in GSEP in the first place (CLF Brief at 7; Sierra Club Brief at 11; CLF/Sierra Club Reply Brief at 6). CLF and Sierra Club contend that the Department should not allow such rudimentary analyses to act as precedent for future filings concerning NPAs, as this near-automatic exclusion cannot reasonably constitute adequate consideration of NPAs (CLF Brief at 7; Sierra Club Brief at 11; CLF/Sierra Club Reply Brief at 7). Instead, Sierra Club

argues that the Department should ensure NPAs are meaningfully considered and prioritized as an alternative to GSEP pipeline replacement to promote a transition to decarbonized buildings and to put the Commonwealth on track to achieve its climate targets (Sierra Club Brief at 18). CLF and Sierra Club urge the Department to assess whether LDCs undertook meaningful NPA analyses until a final framework for NPA analysis is established (CLF/Sierra Club Reply Brief at 7).

Sierra Club also disputes the LDCs' practice of conducting more GSEP projects if the LDCs proceed with NPAs for other, higher-priority GSEP projects (Sierra Club Brief at 11-12). Sierra Club argues that this practice will result in higher near-term costs for ratepayers, as they will pay for both the additional GSEP project and the NPA, while replacing pipe that may not pose a near-term safety risk (Sierra Club Initial Brief at 12).

In addition, Sierra Club maintains that the Department should provide direction to the LDCs regarding the timeline for analysis of NPAs, requiring the LDCs to plan and evaluate NPAs for projects well in advance of the date the pipeline project is planned to commence. Specifically, Sierra Club calls for a ten-year GSEP project forecast with an initial NPA analysis of the projects therein (Sierra Club Brief at 19). Sierra Club urges the Department to direct the LDCs to file an NPA analysis with a cost-benefit assessment for all planned projects through December 31, 2035 for the upcoming GSEP filings for 2026, as well as to direct the LDCs to evaluate NPAs programmatically by investment type (Sierra Club Brief at 19).

3. Companies

The LDCs assert that they complied with the Department's directives and utilized their interim NPA analysis frameworks when developing their 2025 GSEPs (LDCs Reply Brief at 52). The LDCs assert that the fact that some LDCs' NPA analysis did not identify any suitable NPA projects does not mean that the interim NPA analysis frameworks were somehow deficient, suspect, or flawed (LDCs Reply Brief at 52). Instead, the LDCs assert that the interim NPA analysis frameworks appropriately address the need for the LDCs to carefully account for risk, benefits, and costs when evaluating the potential implementation of NPAs (LDCs Reply Brief at 52).

In addition, the LDCs assert that the Attorney General's argument that the LDCs should select NPAs even if the total cost is higher than pipe replacement cost is inconsistent with the Department's statement that an LDC may choose not to implement an NPA because it is cost prohibitive (LDCs Reply Brief at 53). The LDCs' also assert that the Attorney General overstates the potential cost savings associated with NPAs related to decommissioning costs (LDCs Reply Brief at 53).

The LDCs further argue that the Department should reject the Attorney General's recommendation that when an LDC identifies a potential NPA, it should be prohibited from adding another leak-prone pipe replacement project to its GSEP (LDCs Reply Brief at 54-55). The LDCs assert that this recommendation is contrary to the requirement that a GSEP include a plan for removing or remediating all leak-prone infrastructure on an accelerated basis (LDCs Reply Brief at 54-55). In addition, the LDCs maintain that Sierra Club's

recommendation for the requirement of NPA analyses to include cost-benefit assessments for all planned projects through December 31, 2035 is not feasible considering the frequency and rapidity at which leak-prone pipe risk profiles change and the LDCs' obligation to comply with their DIMPs to ensure safe and reliable distribution service (LDCs Reply Brief at 59, citing Exh. LDC-Rebuttal-1, at 61).

C. Analysis and Findings

The Department recognizes that for the 2025 GSEPs, the LDCs relied on an interim NPA analysis framework pending the separate adjudication of a long-term NPA analysis framework. Given the accelerated and annual review of GSEP filings, we find that the LDCs' interim analysis framework is sufficient for purposes of the 2025 GSEPs only. Nonetheless, it appears that the LDCs are continuing with business as usual for the 2025 GSEPs without regard to the Department's mandates in D.P.U. 20-80-B, and we expect the LDCs to sharpen even their interim NPA analysis framework for the forthcoming 2026 GSEPs. We agree with the Attorney General that one aim of the NPA analysis is to prevent investment in new gas infrastructure that will likely be decommissioned or become redundant as the Commonwealth pursues its decarbonization goals.

We direct the LDCs to address deficiencies in their 2025 GSEPs' NPA analysis in their 2026 proposals. Specifically, based on the information provided in the instant dockets, it is difficult to determine whether the LDCs adequately considered NPAs. See, e.g., D.P.U. 24-GSEP-05, Exhs. EGMA-RJB-1, App. A; DPU 1-6; DPU 2-6; AG 1-27; AG 1-28. The Department expects, however, that the LDCs will provide additional

documentation demonstrating that they adequately considered NPAs in the 2026 GSEPs that will be filed on October 31, 2025.

The Department also acknowledges that embarking on a new framework will take time to develop and may include some adjustments based on the final NPA analysis framework. In addition, the Department expects the LDCs to integrate consideration of NPAs into their medium and long-term planning. In this regard, we agree with Sierra Club that the LDCs should be required to plan and evaluate NPAs for projects well in advance of the date the pipeline project is planned to commence.²⁹ We will evaluate this issue further and provide additional guidance in the CCP proceedings, D.P.U. 25-40 through D.P.U. 25-45, in our analysis of the sufficiency of the proposed NPA framework.³⁰ It is essential that the LDCs prioritize NPAs as an alternative to leak-prone pipe measures to assist the Commonwealth in achieving its climate targets, and that the NPA analysis be fully integrated into their planning process. Failure to do so will run the risk of a disallowance of GSEP-related costs, given the burden imposed on the LDCs in D.P.U. 20-80-C at 21-22 to

²⁹ In these dockets, the projects that LDCs found potentially viable for NPAs were removed from their proposed 2025 projects because of the time needed to determine the viability. *See, e.g.*, D.P.U. 24-GSEP-05, Exhs. EGMA-RJB at 11-12; EGMA-RJB-1, at 54; D.P.U. 24-GSEP-06, Exhs. ES-RJB at 12; ES-RJB-1, at 41. Thus, the projects were removed since the work on them will not be performed in 2025. In these instances, it is acceptable for the LDCs to replace the removed projects with other projects that will be completed in 2025.

³⁰ While the intervenors suggest requiring a cost-benefit analysis to compare non-NPA projects and NPA projects, the Department declines to take this action at this time. Instead, such a requirement will be considered after the NPA framework is finalized in the CCP dockets. D.P.U. 25-40 through D.P.U. 25-45.

demonstrate consideration of NPAs as a condition precedent to recovery of additional investment in natural gas distribution infrastructure, including projects included in GSEPs.

VIII. DEPRECIATION

Consistent with the Department's obligation to maintain affordability of gas service and to ensure that the GSEPs operate in a balanced manner, we are concerned that the LDCs may be exposing customers to excessive depreciation charges in accounting for pipe replacements under the GSEPs. The evidence in this case indicates that when existing pipe is retired in favor of replacement pipe, the existing pipe typically is abandoned in place rather than removed from the ground. D.P.U. 24-GSEP-03, Exhs. DPU 1-12; SC 4-1(f). For example, Boston Gas noted that there may be very rare exceptions in cases where field conditions require the replaced pipe to be removed. D.P.U. 24-GSEP-03, Exh. DPU 1-12. The process is referred to as "cut and cap" rather than removal, which produced an average "cost of removal" per foot of \$19 over the past five years, in the case of Boston Gas. D.P.U. 24-GSEP-03, Exh. SC 4-1, Att. At the same time, the depreciation study currently in place for Boston Gas (approved in Boston Gas Company, D.P.U. 20-120, at 257 (2021)) assumes a negative 80 percent net salvage value for assets booked to Accounts 367 (mains) and 380 (services) respectively. D.P.U. 24-GSEP-03, Exh. SC 4-1(d). Under the Uniform System of Accounts, "net salvage value" is defined as "the salvage value of property retired *less the cost of removal*." 220 CMR 50.00 (emphasis added.) "Cost of removal," in turn, is defined as "the cost of demolishing, dismantling, tearing down or otherwise removing utility plant, including the cost of transportation and handling incidental thereto." 220 CMR

50.00. If the decommissioned pipes are not actually removed but are abandoned in place, it is not clear how use of a negative 80 percent net salvage value comports with the Uniform System of Accounts or reflects the costs that the utility actually incurs in decommissioning pipe at the end of its useful life.

There is an insufficient record in this proceeding to make any findings on this issue, as it only indirectly affects the costs incurred by the LDCs under their GSEPs. At the same time, we want to ensure that depreciation charges going forward reflect the practices currently followed by LDCs with respect to the treatment of existing pipe upon its replacement (i.e., removal versus abandoning pipe in place, or “cut and cap”), as the cost implications for customers are far different depending upon the practice. Accordingly, we hereby direct National Grid to file an updated depreciation study in its next base distribution rate case. That depreciation study shall, among other things, reflect a calculation of the net salvage value that is consistent with National Grid’s current practice.³¹

³¹ With respect to previous depreciation charges based on net negative salvage values that are potentially not reflective of the actual costs incurred by LDCs upon pipe decommissioning, the Department will explore that issue in our review of CCPs filed by the LDCs in the CCP dockets. D.P.U. 25-40 through D.P.U. 25-45. Consistent with our obligation under the 2024 Climate Act to minimize customers’ financial exposure to stranded assets, we will include within this examination the issue of the potential mismatch between the LDCs’ existing and previous collection of depreciation charges based on a negative 80 percent net salvage value (based on removal of the existing pipe) versus abandonment of the pipe in place, which potentially has resulted in a substantial over-collection of depreciation charges over time. That over-collection, in turn, could affect the financial exposure to customers from stranded assets and correspondingly could reduce the level of decommissioning costs ultimately borne by customers.

Depending upon what the updated depreciation study shows, other remedies are available to protect customers from excessive depreciation charges. For example, a separate fund could be established for the collection of estimated decommissioning costs, to ensure that the funds collected from customers for the purpose of decommissioning are available for that purpose when it comes time to decommission the assets. Another possible solution is to eliminate the recording of net negative salvage value as part of depreciation charges, and simply have the LDC expense the “cut and cap” costs upon decommissioning of a pipe as those costs are actually incurred. Assuming the costs reported by Boston Gas of \$19 per foot, or \$100,320 per mile,³² are representative of the costs of abandoning the pipe in place, expensing pipe-decommissioning costs could be a far more affordable solution for customers than allowing the LDCs to continue to include net negative salvage value in their depreciation charges. As discussed above, the Department will further investigate each LDC’s decommissioning practices, related depreciation charges, and appropriate charges in the CCP dockets and base distribution rate case dockets.

IX. ORDER

Accordingly, after notice, opportunity to comment, and due consideration, it is

ORDERED: That the petition of Boston Gas Company for approval of a 2025 gas system enhancement plan is APPROVED; and it is

³² \$19 per foot times 5,280 feet.

FURTHER ORDERED: That the gas system enhancement adjustment factors of Boston Gas Company's Boston Gas Division in the amounts of \$0.2208 per therm for residential customers, \$0.2188 per therm for small commercial and industrial customers, \$0.1886 per therm for medium commercial and industrial customers, \$0.1701 per therm for large commercial and industrial customers, and \$0.1302 per therm for extra-large commercial and industrial customers, to take effect on May 1, 2025, are DENIED; and it is

FURTHER ORDERED: That the gas system enhancement adjustment factors of Boston Gas Company's Boston Gas Division in the amounts of \$0.2150 per therm for residential customers, \$0.2131 per therm for small commercial and industrial customers, \$0.1837 per therm for medium commercial and industrial customers, \$0.1657 per therm for large commercial and industrial customers, and \$0.1268 per therm for extra-large commercial and industrial customers, to take effect on May 1, 2025, are APPROVED; and it is

FURTHER ORDERED: That the excess revenue requirement for Boston Gas Company's Boston Gas Division deferred for recovery in future years in the amount of \$5,314,607 is APPROVED; and it is

FURTHER ORDERED: That the gas system enhancement adjustment factors of Boston Gas Company's Colonial Gas Division in the amounts of \$0.0746 per therm for residential customers, \$0.0636 per therm for small commercial and industrial customers, \$0.0612 per therm for medium commercial and industrial customers, and \$0.0257 per therm for large commercial and industrial customers, to take effect on May 1, 2025, are APPROVED; and it is

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.