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March 24, 2025

Mark D. Marini, Secretary
Massachusetts Department of Public Utilities
One South Station, 3rd Floor
Boston, MA 02110

Re: ***Fitchburg Gas and Electric Light Company d/b/a Unitil; The Berkshire Gas Company; Boston Gas Company d/b/a National Grid; Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty; Eversource Gas Company of Massachusetts d/b/a Eversource Energy; and NSTAR Gas Company d/b/a Eversource Energy,***
D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06

Dear Secretary Marini:

Enclosed for filing please find the Office of the Attorney General's Initial Brief. Please file according to your usual practice.

Thank you for your attention to this matter.

Respectfully submitted,

/s/ Mary R. Gardner
Mary R. Gardner
Assistant Attorney General

Enclosures

cc: Carol Pieper, Hearing Officer
Elyssa Klein, Hearing Officer
W. Jay Lee, Hearing Officer
Service Lists

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INITIAL BRIEF OF THE OFFICE OF THE ATTORNEY GENERAL

I. BACKGROUND

On October 31, 2024, each local gas distribution company ("LDC" or "company")[1] submitted its 2025 Gas System Enhancement Program ("GSEP") plan to the Department of Public Utilities ("Department"). The GSEP plans included information regarding leak-prone pipe ("LPP") remediation and associated costs pursuant to *An Act Relative to Natural Gas Leaks*, c. 149 of the Acts of 2014, codified as G.L. c. 164, §§ 144 and 145 ("GSEP Statute").

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

The Legislature passed the GSEP Statute in 2014 to address leaking and aging natural gas infrastructure and to improve the safety and reliability of the Commonwealth's distribution system.[2] Each year, on or before October 31, an LDC may submit a GSEP plan to the Department, detailing the company's proposed GSEP projects for the subsequent construction year to remediate LPP.[3] Thereafter, the Department reviews and decides whether to approve or reject the plan within six-months of filing.[4] After the GSEP work is completed, the LDC may file for cost recovery through the GSEP reconciliation mechanism ("GREC").[5] Once again, the Department has six months to consider whether: (1) the LDC substantially complied with the Department's approved GSEP plan; and (2) the LDC prudently and reasonably managed the costs of its investments.[6] The GSEP Statute entitles the LDCs to accelerated cost recovery for "eligible infrastructure measures,"[7] subject to a cap, which shall not exceed "(i) 1.5 percent of the gas company's most recent calendar year total revenues . . . 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 firm revenues."[8] In 2019, the Department raised the revenue cap to 3 percent for all LDCs.[9]

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2 Exh. AG-DL-DM-1, at 5–7.

3 G.L. c. 164, §§ 145(d).

4 G.L. c. 164, §§ 145(d) and (e).

5 G.L. c. 164, § 145(f).

6 G.L. c. 164, §§ 145(f) and (h).

7 G.L. c. 164, § 145(a).

8 G.L. c. 164, § 145(f).

9 *Unitil*, D.P.U. 18-GSEP-01, Order, at 24–27 (2019).

In the 2025 GSEP plans, the LDCs seek approval for investments totaling $879.6 million,[10] with rate approvals for effect May 1, 2025. If approved by the Department, the LDCs' revenue requirement for 2025 will collectively *increase* by $93.8 million in connection with proposed GSEP spending:

Docket	**LDC**	**Proposed 2025 Revenue Requirement Increase**[11]
24-GSEP-01	Unitil[12]	($463,960)
24-GSEP-02	Berkshire Gas[13]	$3,396,598
24-GSEP-03	National Grid[14]	$46,275,673
24-GSEP-04	Liberty Utilities[15]	$3,015,517
24-GSEP-05	EGMA[16]	$19,618,097
24-GSEP-06	NSTAR Gas[17]	$21,916,377
	TOTAL:	**$93,758,302**

10 *See Unitil*, D.P.U. 24-GSEP-01, Exh. Unitil-DTN-2, Sch. 2, line 46; *Berkshire Gas*, D.P.U. 24-GSEP-02, Exh. BGC-DBS-2, Sch. 2c, line 14; *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-MS/CSS-3, at 1, line 4; *Liberty*, D.P.U. 24-GSEP-04, Exh. LU-KMJ-2, Sch. 1.1; *EGMA*, D.P.U. 24-GSEP-05, Exh. EGMA-ANB-1, Sch. 2 - 2025, line 55; and *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. ES-ANB-1, Sch. 2G, line 56.

11 These figures represent the proposed increase in the total revenue requirement being charged through the GSEP component of the gas bill. The amount represents the difference between the proposed GSEP revenue requirement in the LDCs' filings and the GSEP revenue requirement in their 2023 GSEP filings.

12 *Unitil,* D.P.U. 24-GSEP-01, Exh. Unitil-DTN-2, Sch. 1, line 12.

13 *Berkshire Gas*, D.P.U. 24-GSEP-02, Exh. BGC-DBS-2, Sch. 1, line 22.

14 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-MS/CSS-2, at 1, line 23.

15 *Liberty*, D.P.U. 24-GSEP-04, Exh. LU-KMJ-2, at line 4.

16 *EGMA*, D.P.U. 24-GSEP-05, Exh. EGMA-ANB-1, Sch. 8, line 1.

17 *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. ES-ANB-1, Sch. 9, line 12.

In September 2024, the Attorney General's Office ("AGO") filed a notice of intervention pursuant to G.L. c. 12, §§10 and 11E and the common law authority to represent and protect the public interest.[18] Also, in September 2024, the Department issued a procedural memorandum requiring the LDCs to provide testimony and exhibits in response to a series of questions intended to aid the Department's review of the GSEP plans.[19] The Department's questions required the LDCs to consider their GSEP plans in the context of the Commonwealth's transition away from greenhouse-gas ("GHG") emitting fuels and towards electrification and renewable energy.[20] Based on the substantial record evidence, the AGO requests the Department make the following findings:

- The GSEP program must be reconciled with climate-focused legislative and regulatory changes;
- The LDCs must reduce excessive and imprudent spending on new natural gas infrastructure;
- The LDCs' significant departure from their Department-approved GSEP plans undermines the regulatory process;
- The LDCs' administration of the GSEP program is inconsistent with the "worst-first" requirement of the gas distribution integrity management program ("DIMP"); and
- The Department has broad authority and discretion to administer the GSEP program and intends to exercise this authority to make the GSEP program more affordable and compliant with the Commonwealth's climate mandates.

As ratepayer advocate, the AGO makes the following recommendations to reduce cost burdens on ratepayers and to better align the GSEP program with the Commonwealth's climate mandates. Specifically, the AGO respectfully recommends the Department:

- gradually lower the GSEP cap over the next 3 years to the statutory minimum cap of 1.5 percent;

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18 D.P.U. 24-GSEP-01 through -06, AGO Notice of Intervention (Sept. 13, 2024).

19 2025 GSEP Filings - Procedural Memorandum (Sept. 13, 2024).

20 *Id.*

- require the LDCs to resubmit their 2025 GSEP plans to reflect a 2.5 percent cap;
- clarify the evidentiary burden for the LDCs' requirement to "prudently manage project costs";
- clarify the evidentiary burden for the LDCs' requirement to "substantially comply with a plan";
- define "stranded assets" and provide guidelines for stranded asset cost-benefit analysis; and
- require the LDCs to integrate their GSEP plans into the Climate Compliance Plans ("CCPs") and other integrated energy planning ("IEP") efforts.

II. ARGUMENT

A. The GSEP Program Must be Reconciled with Climate-Focused Legislative and Regulatory Changes.

The Department's procedural memorandum asked each LDC to address whether "circumstances changed since the Department adopted the existing 3.0 percent revenue cap in D.P.U. 18-GSEP-02."[21] The AGO maintains that the circumstances surrounding GSEP have changed significantly, thereby necessitating adjustments to the GSEP program.[22] For example, since the Department's order in D.P.U. 18-GSEP-02,[23] Massachusetts lawmakers have established ambitious GHG emissions reductions mandates that indicate a clear intent to transition the Commonwealth to electricity and renewable energy.

First, in 2021, *An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy* ("Chapter 21N") established a statutory mandate for net-zero GHG emissions by the year 2050 and at least a 50 percent reduction in GHG emissions by 2030.[24] Further, Chapter 21N required the Executive Office of Energy and Environmental Affairs ("EEA") to create a Clean

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21 2025 GSEP Filings - Procedural Memorandum, at 4.

22 AGO Comments (Dec. 19, 2024).

23 *Berkshire Gas*, D.P.U. 18-GSEP-02, Order, at 18, 21 (Apr. 30, 2019).

24 G.L. c. 21N, §§ 3, 3A, and 4.

Energy and Climate Plan ("CECP") every five years to ensure the GHG emissions mandates are met.[25] The Massachusetts CECPs for 2025/2030 and 2050 mandate that the buildings sector, which includes emissions attributable to customer combustion of natural gas, must achieve at least a 47 percent reduction from 1990 GHG emissions levels by 2030[26] and a 93 percent reduction by 2050.[27]

Second, in 2022, *An Act Driving Clean Energy and Offshore Wind* established the GSEP Working Group, charged with developing a report for the Legislature with recommendations to better align the GSEP statute with the Commonwealth's climate goals.[28] This legislation also amended the GSEP statute by: (1) requiring LDCs to consider including the use of advanced leak repair technology; and (2) allowing LDCs to recover the costs through GSEP of replacing GSEP-eligible gas infrastructure with "utility-scale non-emitting renewable thermal energy infrastructure," such as geothermal systems.[29]

More recently, in 2024, the Legislature passed *An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers* ("2024 Climate Act"), which made several key amendments to the GSEP Statute.[30] First, the amended GSEP Statute now requires the Department to review the LDCs' interim GSEP targets "to ensure each gas company is meeting the appropriate

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25 EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030, at 52 (Jun. 30, 2022), available at: https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download.

26 *Id*.

27 EEA, Massachusetts Clean Energy and Climate Plan for 2050, at 55 (Dec. 2022), available at: https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.

28 St. 2022, c. 179, § 68.

29 *Id.* § 58.

30 St. 2024, c. 239, § 81.

pace to reduce the leak rate in a safe and timely manner and *comply with the limits and sublimits established pursuant to chapter 21N of the general laws*."[31]

Second, the GSEP plans must now include "a description of customer costs and benefits under the plan, including the costs of potential stranded assets and the benefits of avoiding exposure to such assets."[32] Remarkably, the LDCs initially claimed in this proceeding that "[t]o the extent that there could be stranded assets on the gas distribution system . . . that issue is not within what we understand to be the scope of the GSEP statute or docket."[33] This repudiation of the Legislature's statutory amendment was later walked back in the evidentiary hearing, where National Grid instead asserted that it did not have sufficient time to analyze stranded assets in this docket, but would do so in the future.[34] Finally, the original statutory language of "eligible infrastructure replacement" was replaced with "eligible infrastructure measure," emphasizing that pipe-for-pipe replacement should not be the only or default means of remediating leak-prone pipe.[35]

Likewise, in D.P.U. 20-80 ("Future of Gas"), the Department's landmark order established that LDCs can no longer conduct "business as usual" but instead must play an active role in achieving the Commonwealth's climate mandates.[36] The Order identified electrification as a primary means of decarbonization and required the LDCs to conduct non-gas pipeline alternative

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31 *Id*. (emphasis added).

32 *Id*.

33 Exh. LDC-Rebuttal-1, at 29.

34 D.P.U. 24-GSEP-01 through -06, Evidentiary Hearing Transcript, at 59–60 (Mar. 7, 2025).

35 St. 2024, c. 239, § 81.

36 *Future of Gas*, D.P.U. 20-80-B, Order, at 18 (Dec. 6, 2023) ("It is important, for example, for LDCs to move beyond 'business as usual' practices toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth's GHG emissions reductions targets.").

("NPA") analysis before continuing to invest in natural gas infrastructure.[37] Additionally, in D.P.U. 20-80-C, the Department unequivocally established that it "did not carve out GSEP or any other project category as exempt from the NPA analysis requirement."[38]

Taken together, these actions demonstrate a clear intent from the Legislature, EEA, and the Department to depart from business-as-usual natural gas investment through GSEP, and to instead focus investment on costs necessary for safety and reliability while transitioning the Commonwealth towards electrification and renewable energy.

1. GSEP encourages investment in new gas infrastructure.

The GSEP program incentivizes the LDCs to invest in natural gas infrastructure. Through the accelerated cost recovery mechanism, LDCs may recover the costs of their capital investments from ratepayers outside of regular base rate cases. As discussed below, accelerated cost recovery encourages the LDCs to maximize investments in upgrading the gas distribution system, and those costs have dramatically increased over time. As a result, GSEP has become a significant driver of ratepayers' gas bills. Gas ratepayers are paying to prop up the gas system infrastructure, while also paying for Massachusetts' decarbonization efforts. Recently, the Department approved a $4.5 billion budget for the Mass Save® energy efficiency programs.[39] It is simply antithetical and unfair to ratepayers to approve costly, unnecessary gas infrastructure upgrades while also requiring ratepayers to foot the bill for costly investments in pursuit of clean energy transition goals. The LDCs' current administration of the GSEP program is at odds with the Commonwealth's

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37 *Id*. at 98.

38 *Future of Gas*, D.P.U. 20-80-C, Order, at 21 (Apr. 2, 2024) ("The Department did not carve out GSEP or any other project category as exempt from the NPA analysis requirement in its Order and we will not do so as a clarification here.").

39 *2025-2027 Statewide Three-Year Plans*, D.P.U. 24-140 through 24-149, Order, at 1–3 (Feb. 28, 2025).

decarbonization goals. At this critical juncture, the GSEP program should be reconciled with climate mandates, which necessarily includes a reduction in GSEP spending.

2. GSEP does not sufficiently address GHG emissions limits for the natural gas sector.

The LDCs use two metrics to estimate the amount of methane leaking from gas pipes. First, the LDCs measure and report lost and unaccounted for gas ("LAUF") by measuring metered lost gas from the distribution system.[40] Second, the Companies estimate GHG emissions using a reporting methodology established by the Massachusetts Department of Environmental Protection ("Mass DEP") based on deemed emissions, meaning the pipeline material is deemed to emit or leak a certain amount of gas per mile.[41] Emissions from gas leaks ("Scope 1 emissions") are categorized as distribution sector emissions.[42] Addressing distribution sector emissions, although important, is not nearly sufficient to meet the Commonwealth's GHG emissions limits for the broader natural gas sector.[43] The amended GSEP Statute, which requires compliance with all "*limits and sublimits* established pursuant to chapter 21N of the general laws,"[44] requires the LDCs to also consider buildings sector emissions, which includes emissions attributable to customer combustion of natural gas ("Scope 3 emissions").[45] While the distribution sector is tasked with reducing emissions from 0.6 million metric tons carbon dioxide ("$MMTCO_{2e}$") in 2020 to 0.4

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40 D.P.U. 19-44-A, Appendix C (Dec. 31, 2019) (guidelines for reporting LAUF pursuant to G.L. c. 164, § 147 and 220 CMR 115.00).

41 310 CMR 7.73 (Mar. 2021) (requiring each LDC to annually report emissions from the total miles of mains and service pipelines by material type, and to report the total miles of mains and service pipelines by material type and age).

42 EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030, at 72

43 Exh. AG-DL-DM-1 at 21.

44 St. 2024, c. 239, § 81 (emphasis added).

45 EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030, at 46–47.

$MMTCO_{2e}$ in 2030, the buildings sector must reduce emissions from 19.5 $MMTCO_{2e}$ in 2020 to 12.5 $MMTCO_{2e}$ in 2030.[46] Put simply, the emissions attributable the buildings sector are far greater than the emissions attributable to the distribution sector, and the buildings sector emissions must decrease by a greater percentage in order to reach the limits at the 2030 benchmark.

For example, EGMA reported that, in 2023, its gas sales to customers resulted in GHG emissions of 2.81 $MMTCO_{2e}$.[47] EGMA's proposed 2025 GSEP projects are estimated to avoid only 0.002 $MMTCO_{2e}$, which would amount to a 5.9 percent reduction in distribution sector emissions, and a 0.06 percent reduction in building sector emissions.[48] A reduction of less than a tenth of a percent of EGMA's buildings sector emissions is insufficient to achieve the significant reduction required by the CECP. Moreover, upgrading LPP with new pipe is likely to entrench reliance on the natural gas system, locking in buildings sector emissions for years to come.

Furthermore, even the Scope 1 emissions data reported in the 2024 GSEP dockets is irreconcilable. The LAUF estimation is a measure of the difference between the amount of natural gas that enters the LDCs' distribution system, and the amount metered to customers.[49] Remediating LPP should reduce LAUF by stopping gas leaks; yet EGMA, NSTAR Gas, and National Grid each reported an increase in their LAUF percentage:

- EGMA's LAUF percentage rose from 1.46 percent in 2019 to 2.88 percent in 2023;[50]
- NSTAR Gas' LAUF percentage rose from 1.35 percent in 2019 to 2.36 percent in 2023;[51] and

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46 Exh. AG-DL-DM-1 at 22 (citing EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030, at 52, 75).

47 *EGMA*, D.P.U. 24-GSEP-05, Exh. AG-1-8.

48 *Id.*, Exh. AG-1-9, Att. AG-1-9.

49 Exh. AG-DL-DM-1 at 20.

50 *EGMA*, D.P.U. 24-GSEP-05, Exh. AG-1-8.

51 *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. AG-1-8.

- National Grid's LAUF for the Boston Gas service territory rose from 3.79 percent in 2019 to 4.08 percent in 2023.[52]

At the evidentiary hearing, Department Chair Van Nostrand questioned National Grid about the inconsistencies in their LAUF estimation.[53] In response, National Grid asserted that LAUF included "other areas like maintenance work that's being done that may result in emissions or venting and purging lines on the system from work that's done in a single year."[54] While LAUF and emissions are different measures, the measures should logically move in the same direction over several years. Because LAUF measures *actual* leaks based on metered gas (as opposed to estimated leaks based on pipe type), the LDCs' reported LAUF data does not support their argument that costly investment in new natural gas infrastructure results in meaningful GHG emissions reductions. Actual metered lost gas data indicates that actual Scope 1 GHG emissions for these three LDCs have increased.

The AGO requests the Department find that (1) the GSEP program, in its current form, is at cross purposes with climate-focused legislative and regulatory developments; and (2) business-as-usual GSEP spending is not resulting commensurate reductions in GHG emissions and will not be sufficient to reach the Commonwealth's emissions limits and sublimits.

B. LDCs Must Reduce Excessive and Imprudent GSEP Spending.

1. GSEP has become a system-wide capital improvement plan.

The GSEP program was designed as a financing mechanism the LDCs could utilize to prudently and reasonably mitigate safety and system reliability risks caused by aging natural gas

52 *National Grid,* D.P.U. 24-GSEP-03, Exh. AG-1-8.

53 Tr. Vol. 1, at 67–68.

54 *Id.* at 68–69.

infrastructure.[55] Over the past decade, unfortunately, GSEP has morphed into a tool for system-wide capital replacements with little regard for targeted replacements and prudent cost management. Since 2015, the LDCs reported GSEP capital expenditures ("CapEx") totaling approximately \$6.2 billion.[56] The pace of GSEP CapEx spending has increased by an average of 11.9 percent per year—from \$291 million per year in 2015 to \$880 million per year in 2025.[57] In 2023, the LDCs' financial statements reported total CapEx of nearly \$1.5 billion with GSEP accounting for more than half of the LDCs' total capital investments.[58] This staggering level of spending far exceeds prudent and reasonable investment in safety and system reliability.

The excessive cost of GSEP is due to the LDCs' nearly exclusive focus on replacing *all* LPP with new gas pipe. Since the GSEP program began in 2014, the LDCs have used replacement as the primary means of remediating GSEP-eligible infrastructure.[59] Over ten years ago, upgrading LPP with new pipe made sense because the Commonwealth reasonably expected continued reliance on natural gas. As discussed above, the Commonwealth has since taken clear and decisive steps away from GHG-emitting fuels and towards electrification and renewable energy, and these legislative and regulatory developments explicitly and implicitly alter the requirements of the GSEP program. Given these changes, replacing all LPP with new gas pipe is increasingly uneconomic and imprudent. This is especially true given the rising costs of pipe replacement.

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[55] D.P.U. 24-GSEP-01 through 24-GSEP-06, Chairman Barrett Comments (Jan. 10, 2025); G.L. c. 164, §§ 145(b)-(f).

[56] Exh. AG-DL-DM-1, at 8–10.

[57] *Id.*; *supra* note 10.

[58] Exh. AG-DL-DM-1, at 8–10.

[59] *Id.* at 29–30.

The costs of pipe replacement have increased significantly due to inflation, new contracts, and construction cost factors.[60] For example, National Grid's cost per mile to replace LPP increased by 49 percent over the five-year period from 2019 to 2023 for its Boston Gas service territory.[61] National Grid's current average cost of leak-prone main replacement is a staggering $3.3 million per mile.[62] For EGMA, the cost per mile to replace LPP has increased by approximately 8 percent between 2018 and 2023, up to $2 million per mile.[63] The LDCs purport that GSEP projects are becoming increasingly complex, which will require more time, more resources, and greater costs per mile.[64]

If the LDCs continue to administer GSEP as predominately a pipe replacement program, a conservative estimate of remaining GSEP investment costs exceeds $13.7 billion.[65] The following chart from the AGO's expert testimony shows the estimated total cost to replace all LPP remaining on the LDCs' gas distribution systems:[66]

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60 *Id*. at 28–29.

61 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-1, at 15.

62 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-2, at 43.

63 *EGMA,* D.P.U. 24-GREC-05, Exhs. AG-1-4; EGMA-RJB-2.

64 *See, e.g., Liberty,* D.P.U. 24-GSEP-04, Exh. LU-NMW-1, at 6 ("Liberty anticipated that progress in successfully completing these upcoming GSEP projects will be slower, will require the allocation of more resources, and will ultimately be more expensive to complete").

65 Exh. AG-DL-DM-1, at 30–31.

66 *Id*.

Remaining Statewide GSEP Costs

	Remaining Miles	Year End of Remaining Miles	Cost / Mile	Year of Cost / Mile	Est. Remaining Cost with annual inflator ($M)
Unitil	29	2024	$1,316,699	2024	$45.8
Berkshire Gas	47	2024	$890,757	2024	$54.8
National Grid	2,669	2024	$3,203,667	2023	$10,694.1
Liberty	104	2023	$963,138	2023	$114.6
EGMA	482	2023	$1,998,908	2024	$1,064.9
NSTAR Gas	718	2023	$2,099,380	2024	$1,750.5
Total	**4,049**				**$13,724.7**

Importantly, $13.7 billion is extremely conservative because the AGO's experts escalated the GSEP investment cost per mile at the assumed inflation rate of 2 percent instead of the much higher inflation rates experienced recently.[67] Additionally, $13.7 billion significantly underestimates the total costs to ratepayers since it does not include return on investments and carrying charges in the form of interest. According to the GSEP Working Group Report, some experts estimate that, if the LDCs continue a business-as-usual strategy for GSEP, the total costs will exceed $40 billion.[68]

67 *Id.* at 31.

68 GSEP Working Group Report and Recommendations, at 55 (Jan. 31, 2024), available at: https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act; Dorie Seavey, *Spending billions fixing gas system makes no sense*, Commonwealth Beacon (Apr. 26, 2022), available at: https://commonwealthbeacon.org/opinion/spendingbillions-fixing-gas-system-makes-no-sense/ ("Assuming DPU's approved rate of return on pipeline assets (currently averaging 9.65 percent) and the 60-year asset life for plastic pipes claimed by the gas companies, then the Investigation's annual forecasts indicate total GSEP costs of $40 billion (in constant 2019 dollars)").

GSEP was not meant to be a system-wide infrastructure improvement tool. When the GSEP statute was passed, it was intended to incentivize accelerated remediation of LPP to reduce gas leaks and enhance safety and system reliability with the assumption that the natural gas distribution system would remain in service permanently. In his January 10, 2025 Comments, Senator Michael J. Barrett, Chairman of the Telecommunications, Utilities and Energy Committee, explains that the "unanticipated consequences" of GSEP include "overly aggressive installation of altogether new fossil fuel infrastructure."[69] Importantly, he notes that "[t]he single-note emphasis on wholesale replacement" costs ratepayers more than necessary and promotes excessive GHG emissions that are likely to last past 2050 and even 2060.[70] Given the Commonwealth's ongoing effort to transition away from GHG-emitting fuels, and considering the rising costs of LPP replacement, it is especially important that the LDCs end their business-as-usual practice of upgrading and improving all aging pipe on their gas distribution systems.

2. GSEP costs are unduly burdensome to ratepayers.

GSEP investments are recovered from ratepayers on an accelerated timeline through a charge in their distribution rates. In addition to paying the costs associated with pipe replacement, ratepayers also pay carrying charges for prior years' GSEP expenditure above the cap. Although the GSEP statute establishes a cap, it also allows the LDCs to defer any revenue requirement approved by the Department above the cap for recovery in the following year.[71] The LDCs have a pattern of exceeding the cap set by the Department. For example, in the 2024 GREC proceedings, five out of six LDCs exceeded the 3 percent cap and were, thus, able to defer cost recovery to

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69 Chairman Barrett Comments, at 2.

70 *Id.*

71 G.L. c. 164, § 145(f).

future years.[72] As the deferred amounts increase, it is increasingly difficult for the LDCs to manage costs within the 3 percent cap. NSTAR Gas, for example, has requested a waiver of the cap three times since the Department increased the cap, most recently requesting a waiver that would increase the cap to 6.57 percent.[73] The Department denied the waiver of the cap, citing "the Company's continued inability to manage its GSEP within the cap set by the Department," but allowed NSTAR Gas to defer all above-cap amounts to future years.[74]

The LDCs earn interest on these deferred amounts, which ratepayers must pay over time through distribution rates. This generates profit for the LDC and encourages overspending. The excessive pipe replacement cost, coupled with the LDCs' failure to prudently manage GSEP spending within the cap, feeds burgeoning GSEP costs and leaves ratepayers in the lurch.

Reining in excessive GSEP costs is critical given the ongoing energy affordability crisis in Massachusetts. Natural gas prices have been a focal point in the Commonwealth in recent months as high distribution charges paired with extremely cold weather led to unmanageable gas bills.[75] In response, the Department directed the LDCs to file revised reconciling factors that would result in no less than a five percent reduction in residential and residential low-income average bills for

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72 *Unitil*, D.P.U. 24-GREC-01, Order at 20 (Unitil's incremental revenue requirement exceeds the 3 percent cap by $2,065,451) (Oct. 31, 2024); *National Grid*, D.P.U. 24-GREC-03, Order, at 23 (the Boston Gas Division proposes to defer $29,101,014 for future recovery) (Oct. 31, 2024); *Liberty Utilities*, D.P.U. 24-GREC-04, Order, at 19 (Liberty's entire under-recovery balance of $26,489,401 exceeds the three-percent cap) (Oct. 31, 2024); *EGMA*, D.P.U. 24-GREC-05, Order, at 1 (EGMA's reconciliation exceeds the cap by $2,197,776) (Oct. 31, 2024); *NSTAR Gas*, D.P.U. 24-GREC-06, Order, at 19 (NSTAR Gas requests that the Department grant a waiver of the GSEP cap and increase in the cap to 6.57 percent to allow the Company to recover its total under-recovery balance of $23,709,187) (Oct. 31, 2024).

73 *NSTAR*, D.P.U. 24-GREC-06, Order, at 19.

74 *Id*. at 23–24.

75 *See, e.g.*, Mariam Wasser, *Why your heating bills are so expensive this winter in Mass.*, WBUR (Fe. 25, 2025); available at: https://www.wbur.org/news/2025/02/19/massachusetts-natural-gas-bills-eversource-national-grid-expensive-delivery-rate.

the remainder of the peak season.[76] On February 21, 2025, Attorney General Campbell wrote a letter to Chairman Van Nostrand requesting the Department promptly use all its available authority to provide both immediate and meaningful, long-term relief for ratepayers.[77] This letter identified GSEP as one of the drivers of high natural gas bills.[78]

For example, in 2024, GSEP accounted for 8.33 percent of the average customer's monthly gas bill during the peak season and 10.54 percent of the average monthly gas bill during the off-peak season for NSTAR Gas customers.[79] For the average non-low-income customer, this amounts to a GSEP charge of $25.82 per month during the peak season.[80] For the average low-income customer, the GSEP charge is $18.83 per month during the peak season.[81]

Eliminating excessive GSEP spending, including disallowing excessive GSEP deferrals, will help to alleviate one of the drivers of the gas bill upsurge. Reducing imprudent GSEP spending is especially important as the Commonwealth continues to transition away from GHG-emitting fuels and towards electrification and renewable energy. Most LDCs have acknowledged that the climate mandates necessarily involve some reduction in the size of the natural gas distribution system. For example, National Grid "recognizes that the Commonwealth's pathway to net zero

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76 Department's Letter to LDCs, Immediate Winter Rate Relief, at 1 (Feb. 20, 2025); available at https://media.wbur.org/wp/2025/02/Commission-Letter-to-LDCs-re-Immediate-Bill-Relief.pdf.

77 AG Campbell Letter to the Department, at 1 (Feb 21, 2025); available at https://www.mass.gov/news/in-letter-to-the-dpu-ag-campbell-calls-for-immediate-and-long-term-relief-for-ratepayers.

78 *Id.*; *see also*, Eversource, Understanding Your Winter Natural Gas Bill, at 9 (Feb. 2025) (GSEP accounts for 24 percent of the distribution adjustment charge on the customer's gas bill); available at: https://www.documentcloud.org/documents/25550141-understanding-your-winter-natural-gas-bill-nstar-feb-2025-v3/.

79 *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. AG-1-7.

80 *Id*.

81 *Id*.

implies substantial declines in both gas volumes and customer counts."[82] As gas customers leave the gas distribution system, costs will increase for remaining customers, which should naturally prompt more gas customers to transition to electrification. The AGO has labeled this phenomenon the "price vortex" because it will likely result in gas prices that continue to spiral out of control.[83] As the customer base shrinks, the gas ratepayers who remain on the system will bear the costs of increasingly expensive GSEP investments. These costs will disproportionately burden low-and middle income ("LMI") ratepayers since LMI customers are: (1) more likely to be renters who lack the optionality to switch to electric appliances or heat pumps, and (2) less likely to have the cashflow to cover the up-front costs of transitioning their homes. Reducing LDC spending on new gas infrastructure is essential to protecting ratepayers in the short and long term.

3. GSEP investments are likely to become stranded assets.

It is imprudent and uneconomical to invest an additional $13.7 billion into natural gas infrastructure at time when the Commonwealth is working to meet the required net-zero emissions limit by 2050.[84] As the gas distribution system shrinks, GSEP investments are likely to become stranded assets, which the AGO's testimony defines as an asset that becomes unnecessary or redundant before the end of its nominal useful service life.[85]

LDCs typically replace LPP with new plastic pipe, which is a long-life asset, having a useful life of approximately 40 years.[86] Once a main or service is no longer needed to reliably

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82 *National Grid,* D.P.U. 24-GSEP-03, Exh. AG-1-10, at 2.

83 *Future of Gas*, D.P.U. 20-80, AGO Line Extension Comments, at 8, 15–16 (Oct. 11, 2024).

84 Exh. AG-DL-DM-1, at 31–32.

85 *Id*.

86 *Id.*; *see, e.g., EGMA,* D.P.U. 24-GSEP-05, Exh. EGMA-ANB-1, Sch. 2-2025 in 2025 (Different types of mains have different useful lives ranging from 16.7 for bare steel and 49.5 for plastic mains.).

serve demand, the asset becomes stranded. Assuming Massachusetts achieves its 2050 net-zero emissions goal, many new GSEP investments installed in 2025 will become stranded assets in 2050, when they are only halfway through their deprecation lifespan. This issue is exacerbated as GSEP-approved LPP is replaced in future years. To be clear, the AGO is not suggesting that all natural gas pipes will be out of service by 2050. Rather, the AGO assesses GSEP in the context of the energy transition and emphasizes that upgrading and further entrenching the gas distribution system as gas throughput and customer count declines is uneconomic and imprudent.[87]

In addition to being at cross purposes with the Commonwealth's climate mandates, stranded assets are fundamentally unfair to ratepayers. Ratepayers should not have to pick up the tab for expensive, unnecessary infrastructure upgrades which will likely be decommissioned before the end of their useful lives, while also footing the bill for decarbonization. Additionally, the costs of stranded assets will fall disproportionately on the ratepayers who remain on the gas system as other customers shift towards electrification. It stands to reason that, when the GSEP charge is spread across a smaller customer base, it will account for a greater percentage of those customers' bills.

As discussed above, the recent amendments to the GSEP statute require the LDCs to include "a description of customer costs and benefits under the plan, including the costs of potential stranded assets and the benefits of avoiding financial exposure to such assets."[88] With this mandate, the Legislature recognized the likelihood that certain GSEP investments will become redundant or will be retired before the end of their useful lives and added this requirement to ensure

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87 Exhs. AG-DL-DM-1, at 31–32; AG-DL-DM-Surrebuttal, at 8–9 (March 4, 2025).

88 St. 2024, c. 239, § 81.

prudent investments going forward.[89] In Section III below, the AGO recommends that the Department define stranded assets and provide guidelines for the new, statutorily-mandated stranded asset cost-benefit analysis.

4. LDCs must consider less-costly means of leak remediation.

To reduce the cost burden of GSEP, prevent stranded assets, and better align GSEP with the climate mandates, the LDCs must consider alternatives to replacing LPP with new pipe. In their Joint Rebuttal Testimony, the LDCs state, "[u]ntil all GSEP-eligible work is completed, GSEP will remain a significant portion of capital spending," and it "simply is unsurprising that a significant portion of the LDCs' capital investments relate to pipeline investments because pipe and associated materials is one of the primary assets for each LDC."[90] The LDCs seem to suggest that the GSEP statute grants them the authority to replace *all* LPP 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.[91] This view is inconsistent with the statutory and regulatory changes that require LDCs to consider less costly means of LPP remediation. Going forward, the Department should require that, in addition to replacement of the leakiest pipe, the LDCs' GSEP plans must include decommissioning and implementation of NPAs, targeted decommissioning of non-essential and redundant pipe, repair, and advanced monitoring.

a. Non-Gas Pipe Alternatives

Implementation of NPAs should reduce the costs of the GSEP program. When an LDC replaces LPP with new pipe, it recovers the cost of decommissioning the LPP and the cost of

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89 Chairman Barrett Comments, at 7 ("The Legislature tasked the DPU and the gas companies with weighing stranded asset risks to ratepayers -- and minimizing them.").

90 Exh. LDC-Rebuttal-1, at 17.

91 Exh. AG-DL-DM-Surrebutal, at 1.

installing the new pipe though the GSEP accelerated cost recovery mechanism.[92] When an LDC decommissions LPP as part of a targeted electrification project, it only recovers the costs of decommissioning through the GSEP accelerated recovery mechanism. In fact, even if the total cost (regardless of cost recovery method) of implementing a NPA is higher than the new gas pipe replacement cost, the NPA is likely to be the more prudent investment given the climate mandates and ongoing decarbonization efforts in the Commonwealth.

The interim NPA framework applied by the LDCs in these proceedings was wholly inadequate because the overwhelming majority of GSEP projects were excluded from NPA consideration.[93] Five of the six LDCs excluded 98 to 100 percent of GSEP projects from NPA analysis.[94] National Grid was the outlier in that it excluded 58.6 percent of GSEP projects from NPA analysis.[95] After designating projects as "NPA opportunities," however, National Grid conducted an analysis comparing the costs of NPA implementation to the costs of pipe replacement.[96] In instances where the cost of the NPA exceeded the cost of pipe replacement, the project was categorized as no longer NPA eligible.[97]

NPA analysis is not optional, and it is not a one-for-one cost comparison between the NPA and replacement. 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 electrifies and pursues other decarbonized energy sources. An NPA with a higher *initial* cost

[92] Evidentiary Hearing Transcript, at 50 (Tupper explaining that when you replace LPP with new pipe you also decommission the LPP that was there previously).

[93] Exh. AG-DL-DM-1, at 23–26.

[94] *Id*. at 25.

[95] *Id*.

[96] Evidentiary Hearing Transcript, at 54.

[97] *Id*.

compared to gas pipe replacement is likely to be a more prudent investment because it will be used and useful longer, and it is consistent with Massachusetts' decarbonization goals.

The AGO recognizes that the interim NPA framework will soon be modified based on the work of the D.P.U. 20-80 NPA Working Group. The AGO maintains, however, that it is important to discuss and consider the NPA process in the context of the GSEP dockets. The Department should issue clear directives to the LDCs that, in subsequent GSEP proceedings, the LDCs will not be permitted to exempt the overwhelming majority of GSEP projects from the NPA framework developed by the NPA Working Group.

Furthermore, when a GSEP project is selected for NPA implementation, the LDC should not be allowed to add another pipe replacement project to its GSEP plan. In the evidentiary hearing, National Grid indicated that, if a GSEP project were to "drop off the list" because it has been selected for NPA purposes, it "would look to replace it with another project."[98] It is not clear from National Grid's testimony whether the replacement project would undergo NPA analysis. It is important that LDCs reduce their overall GSEP spending, not maximize spending by adding pipe replacement projects to their GSEP plans simply because other projects were identified as potential NPAs.

b. Targeted Decommissioning Analysis

The AGO recommends that the Department require the LDCs to evaluate their LPP inventory and decommission pipe that does not serve customers (or has become redundant) and is not needed to maintain system reliability. Several LDCs indicated that they perform hydraulic analysis on LPP to determine whether it is essential or non-essential.[99] Non-essential pipe that is

98 Tr. Vol.1, at 60–61.

99 *Id*. at 19–20, 49, 104, 122.

not needed for system reliability should be decommissioned to reduce risks inherent to LPP. It is especially important that the LDCs do not replace LPP with new pipe where the new pipe is already redundant or wholly unnecessary.

Targeted decommissioning analysis alone is not sufficient to comply with the climate mandates, as most pipe at this time will probably still be categorized as "essential." For example, in 2024, Unitil decommissioned only 2.91 miles of leak-prone main and 3 inactive leak-prone services without replacement.[100] That said, targeted decommissioning analysis likely will become increasingly important as more gas customers leave the distribution system. Targeted decommissioning, where possible, can help to prevent costly replacement of gas infrastructure that either has already become, or will likely soon be, redundant due to customer electrification and decarbonization.

c. Repair and Advanced Monitoring

Next, the AGO recommends that the Department require, where possible, the LDCs to opt for pipe repair and advanced monitoring of LPP to delay total pipe replacement while NPAs are implemented. The LDCs purport that replacing LPP with new pipe is the only way to reduce risk on the gas distribution system.[101] On the contrary, the only way to *eliminate* gas risk from material failure is to decommission gas pipe and transition customers to alternative heating systems.[102] Repairing and monitoring non-leaking LPP can extend the life of the pipe until it can be decommissioned and replaced with lower-GHG alternatives. These strategies minimize the costs

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100 *Unitil*, D.P.U. 24-GSEP-01, Exh. AG-1-FGE.

101 Exh. LDC-Rebuttal-1, at 11.

102 Exh. AG-DL-DM-Surrebuttal, at 10–11.

of infrastructure improvements over the long term and support the need to balance accelerated remediation of LPP with the rising cost to ratepayers.

To be clear, replacement of LPP with new pipe will still be necessary in instances where the pipe is actively leaking and presents a high level of risk to safety and reliability. But different segments of pipe present different levels of risk, and not all LPP must be replaced in the near-term. For example, according to National Grid's prioritization factors filed in its GSEP plan, it must replace LPP within 3 years if it has a prioritization factor greater than 20.[103] At the evidentiary hearing, Chair Van Nostrand highlighted that, of the 175 GSEP projects included in National Grid's plan, over 60 had prioritization factors less than 20.[104] Instead of pursuing costly replacement for these projects, the LDCs should repair the pipe or conduct advanced monitoring until the pipe can be decommissioned and replaced with an NPA.

In summary, investing in new natural gas infrastructure with little regard for the actual risk level presented for the segment of LPP is imprudent and increasingly uneconomic. By developing a meaningful NPA process, conducting targeted decommissioning analysis, and implementing strategies for repair and advanced monitoring, the LDCs can significantly reduce the cost of the GSEP program and alleviate the burdens on ratepayers. The AGO requests that the Department find that the LDCs must reduce excessive and imprudent spending by considering less costly means of remediating LPP and avoiding unnecessary expenditures.

103 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-3, at 6.

104 Tr. Vol. 1., at 71.

C. LDCs' Significant Departure from Department-Approved GSEP Plans Undermines the Regulatory Process.

The GSEP statute requires that GSEP plans be considered and adjudicated on a six-month timeline.[105] Consequently, the Department and all parties have limited time to consider the expenditures and investments proposed by the LDCs. Despite this expedited timeline, the Department approves GSEP plans after a full adjudicatory process. Unfortunately, the LDCs frequently disregard the Department's approvals and depart significantly from the approved GSEP plans.

1. LDCs' departure from Department-approved GSEP plans surpasses their need for "flexibility."

The degree of compliance with Department-approved GSEP plans varies by company. For example, on one end of the spectrum, Unitil did not stray far from its 2024 GSEP plans, completing 14 out of 18 projects, deferring 4 projects, and adding 2 unreviewed projects.[106] On the other end of the spectrum, NSTAR Gas completed only 132 out of 279 Department-approved projects in its GSEP plan, while deferring the remaining 147 Department-approved projects and adding 265 new projects.[107] This brazen disregard of the Department's approval meant that NSTAR Gas added nearly as many unapproved projects as had originally been proposed and approved in its GSEP plan.[108] Worse still, National Grid completed only 77 of the 211 Department-approved GSEP

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105 G.L. c. 164, § 145(d)-(e).

106 Unitil, D.P.U. 24-GREC-01, Exh. Unitil-CLTB-1, at 8–10 (Revised).

107 *NSTAR Gas,* D.P.U. 24-GREC-06, Exh. AG-2-4, Att. AG-2-4(a).

108 *Id.*

projects and added 345 new projects.[109] The figure below shows the extent to which the LDCs complied with their Department-approved GSEP plan:[110]

2024 GREC	**Unitil**[111]	**Berkshire Gas**[112]	**National Grid**[113]	**Liberty** [114]	**EGMA**[115]	**NSTAR Gas**[116]
DPU-Approved projects	18	59	211	30	75	279
Completed Projects	14 (77.8%)	37 (62.7%)	77 (36.5%)	12 (40%)	56 (74.4%)	132 (47.3%)
Deferred Projects	4 (22.2%)	22 (37.3%)	110 (52.1%)	18 (60%)	19 (23.3%)	147 (52.7%)
Total Completed Projects	16	94	422	19	140	397
Projects Not on 2023 GSEP Plans	2 (12.5%)	57 (60.6%)	345 (81.8%)	7 (36.8%)	84 (60.0%)	265 (66.8%)

The Department has already expressed concern with the LDCs' pattern of deviating significantly from their GSEP plans. In the 2024 GREC proceedings, the Department directed the LDCs to submit additional evidence to support their decisions to prioritize a new project over a Department-approved project.[117] The LDCs assert that "[a] new or worsening leak can be

109 *National Grid,* D.P.U. 24-GREC-03, Exh. AG-2-3, Att. AG-2-3.

110 Exh. AG-DL-DM-1, at 23–26.

111 *Unitil*, D.P.U. 24-GREC-01, Exh. Unitil-CLTB-1, at 8–10 (Revised).

112 *Berkshire Gas*, D.P.U. 24-GREC-02, Exhs. BGC-JP-3, at 1; AG-2-2, Att. 2-2.

113 *National Grid*, D.P.U. 24-GREC-03, Exh. AG-2-3, Att. AG-2-3.

114 *Liberty*, D.P.U. 24-GREC-04, Exh. LU-NMW-1, at 6–7.

115 *EGMA*, D.P.U. 24-GREC-05, Exhs. AG-2-4, Att. AG-2-4(a); AG-2-6, Att. AG-2-6.

116 *NSTAR Gas,* D.P.U. 24-GREC-06, Exh. AG-2-4, Att. AG-2-4(a).

117 *National Grid*, D.P.U. 24-GREC-03, Order, at 36 (requiring "(1) evidence to support its decision that any new projects should be prioritized over the Department-approved projects; (2) evidence as to whether any new projects displaced an approved project with a higher risk prioritization factor; and (3) where an approved project was canceled due to unforeseen circumstances, evidence that the new replacement project was selected based on appropriate risk prioritization or environmental justice considerations.").

discovered after the GSEP Plan is finalized requiring reprioritization."[118] This development would warrant flexibility. Notwithstanding, it is highly unlikely that all 760 new GSEP projects were due to a new or worsening leak.[119] Instead, LDCs frequently undertake new GSEP projects based on paving moratoriums, roadwork, and other public works projects. For example, EGMA explains that:

> If the Company is notified by a municipality that a paving project is planned on a street, that is not on the Department-approved list, where cast iron, bare steel, or unprotected coated steel facilities exist, the Company will develop and schedule a GSEP project provided the municipality agrees to allow construction prior to paving. In this event, the project will replace or defer a project or projects on the Department-approved list.[120]

Simply put, instead of doing projects that were reviewed and approved by the Department based on their risk to public safety, the LDCs defer those projects and instead complete projects driven by municipal convenience.

2. *Roadwork and impending paving moratoriums should not excuse major departures from the GSEP plans.*

Paving moratoriums and municipal convenience should not be a driver of GSEP projects and should not excuse major departures from the GSEP plans. The LDCs suggest that an upcoming paving moratorium necessitates immediate replacement of LPP because, otherwise, a known risk to system safety and reliability could further deteriorate in the ground for 5 more years.[121] This argument is conclusory. The LDCs have not presented evidence that new GSEP projects in

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[118] Exh. LDC-Rebuttal-1, at 21.

[119] *See, e.g., National Grid*, D.P.U. 24-GREC-03, AG-2-3 ("Projects in the Company's Public Works program are selected on a rolling basis and are based on the timing and type of third-party work rather than on a prioritization factor/risk score . . . The prioritization factor, or risk score, was not available for any of the projects with "N/A" when the decision was made to pursue the project.").

[120] *EGMA,* D.P.U. 24-GSEP-05, Exh. AG-1-22.

[121] Exh. LDC-Rebuttal-1, at 22.

response to road paving present greater safety risks than the Department-approved GSEP projects that were originally identified based on their risk prioritization factors. Risk, not road paving, should determine GSEP work. To be clear, there may be instances where the LDCs should coordinate with municipal paving schedules to remediate high-risk segments of LPP. Going forward, however, it important that the decision to coordinate with municipal paving is based on the actual risk of that segment of LPP.

The LDCs also argue that municipal paving can introduce additional risks since "paving can introduce vibrations and ground movement that can lead to leaks."[122] Though this may be true in some cases, road paving does not necessarily create risks for all LPP sufficient to warrant immediate replacement. The decision to replace LPP with new pipe should always be a risk-based decision. As discussed below, deferring Department-approved projects with higher risk scores in favor of new paving projects with lower risk scores undermines the "worst first" requirement of the DIMP.

As previously noted, "[t]he intent of the Legislature in enacting [G.L. c. 164, § 145] was to accelerate the repair or replacement of aging or leaking natural gas infrastructure (in the interest of public safety and to reduce lost and unaccounted for natural gas) . . . ."[123] The purpose of GSEP is *not* to enable LDCs to conveniently upgrade and replace pipe when paving moratoriums are impending and receive accelerated recovery of the associated costs. The AGO requests the

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[122] *Id*. at 20 n.15.

[123] *Unitil*, D.P.U. 18-GSEP-01, Order, at 25 (Apr. 30, 2019) ("The intent of the Legislature in enacting [G.L. c. 164, § 145] was to accelerate the repair or replacement of aging or leaking natural gas infrastructure (in the interest of public safety and to reduce lost and unaccounted for natural gas), as well as to provide 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.").

Department find that the LDCs' significant departure from the approved GSEP plans undermines the regulatory process and will not be allowed to the same degree going forward.

D. The LDCs' Administration of the GSEP Program is Inconsistent with the "Worst-First" Requirement of the DIMPs.

The Department has asked the LDCs to consider whether lowering the GSEP cap would impact compliance with the LDCs' DIMPs, which are required under 49 C.F.R. §§ 192.1001 through 192.101 ("Part 192").[124] In Section III below, the AGO recommends lowering the GSEP cap; maintaining that doing so would not jeopardize compliance with the DIMPs. In fact, the LDCs' current administration of the GSEP program is inconsistent with Part 192's requirement that LDCs prioritize the greatest risks to system safety and reliability.

1. The LDCs mischaracterize the purpose and function of the DIMPs.

The LDCs' testimony repeatedly mischaracterizes the purpose and function of the DIMPs. First, some LDCs incorrectly testify that the DIMP requires the company to replace all LPP with new pipe. For example, National Grid stated that its "DIMP obligates the Company to replace LPP to mitigate risk on the gas system."[125] On the contrary, Part 192 requires the LDCs to develop an integrity management plan with the following elements: (1) knowledge of threats; (2) identification of threats; (3) evaluation and ranking of risk; (4) identification and implementation of measures to address risks; (5) measure performance, monitor results, and evaluate effectiveness; (6) periodic evaluation and improvement; and (7) report results.[126] In other words, Part 192 requires LDCs to develop plans to mitigate risks on the gas distribution system but does not dictate how LPP should be remediated. According to National Grid's actual DIMP, "[d]ue to the

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124 2025 GSEP Filings – Procedural Memorandum, at 5.

125 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-1, at 10.

126 49 C.F.R. § 192.1007; Exhs. AG-DL-DM-1, at 49; AG-DL-DM-Surrebuttal, at 19–20.

significant diversity among distribution pipeline operators and pipelines, the [Part 192] requirements are high-level and performance-based. [Part 192] specifies the required program elements but does not prescribe specific methods of implementation."[127]

Second, the LDCs' Joint Rebuttal Testimony suggests that the DIMPs preclude the LDCs from considering repair as a mean of remediating LPP. The LDCs state that "repair does not eliminate the safety risk associated with the LPP."[128] The LDCs cite to Representative Roy's comments filed in the GSEP dockets,[129] wherein Representative Roy claims he "engage[d] with the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) on the proposed legislation pertaining to GSEP" [130] and that PHMSA "confirmed the potential for [ ] catastrophic consequences if a robust pipeline integrity management system is not maintained."[131]

Here, the LDCs appear to suggest that repairing pipe does not comply with the DIMP and, according to PHMSA, could result in catastrophic consequences. This is a concerning mischaracterization of the actual letter that PHMSA wrote to Representative Roy. The PHMSA letter states that "[t]he consequence of not addressing or mitigating these risks through a comprehensive pipeline integrity management system can be catastrophic,"[132] but the letter does not suggest that repair is an inappropriate means of LPP remediation. In fact, the letter consistently lists repair as a means of addressing risks on the gas distribution system. In response to a question

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127 *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-14, at 13.

128 Exh. LDC-Rebuttal-1, at 26.

129 Representative Roy Comments (Dec. 18, 2024).

130 *Id*.

131 Exh. LDC-Rebuttal-1, at 27.

132 Letter from United States Department of Transportation Pipeline and Hazardous Materials Safety Administration to Representative Roy ("PHMSA Letter"), (Sept. 11, 2024) (The Department incorporated the letter by reference into the record pursuant to 220 CMR 1.10(3)).

about the cost-effectiveness of investments in leak detection and pipeline repair/replacement, the letter states the following: "PHMSA recently proposed new requirements related to methane leak detection and repair, covering nearly 2.7 million miles, nationally. While PHMSA's authority also does not include economic analyses for rate-making purposes, our regulations must be designed in a cost-effective manner and ensure the benefits of the regulations justify the costs."[133] Moreover, the letter acknowledges that "the GSEP in Massachusetts . . . relates primarily to the rate-making method that the [LDCs] are authorized to use to recover the GSEP-related costs in rates."[134]

Third, the LDCs seem to suggest that, because the GSEP is integrated into the DIMP, the GSEP plan as it is currently administered is required by the DIMP. Specifically, an expert testifying on behalf of Eversource stated that "our GSEP program is part of our DIMP program, and our DIMP program is implemented in accordance with Federal regulation . . . So it is, in my view . . . a requirement of the Federal pipeline safety regulations."[135] This circular argument—that the GSEPs are included in the DIMPs, therefore, the GSEPs are required by Part 192—is unsupported. Again, the requirements of Part 192 are not prescriptive, and they do not require that LDCs replace all LPP with new gas pipe. Any changes to the GSEP program would be reflected in the company's annual DIMP updates.[136] If the Department lowers the GSEP cap and requires the LDCs to seriously consider: (1) NPAs; (2) targeted decommissioning; and (3) pipe repair and

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133 *Id*. at 2.

134 *Id*. at 3.

135 Tr. Vol. 1, at 168–69.

136 *Id.* at 183 (The witness for EGMA testified that the Company updates its DIMP annually and includes statutory changes relevant to the DIMP in its updates.)

advanced monitoring, these changes could be incorporated into the LDCs' DIMP, and they would not jeopardize compliance with Part 192.

2. The DIMPs require the LDCs to prioritize GSEP work based on risk level.

Despite the rule's inherent flexibility, Part 192 is clear that the LDCs should address the greatest risks on their distribution system first. In their DIMPs, LDCs are required to "determine the relative importance of each threat and estimate and rank the risks posed to its pipeline."[137] Some LDCs have acknowledged the obligation to prioritize LPP remediation based on risk factor. For example, NSTAR developed an internal computer model to "analyze and prioritize main segments for replacement under a 'worst first' concept."[138] Yet, the LDCs frequently defer GSEP projects that were selected because of their risk factors in favor of GSEP projects that align with municipal paving schedules. The AGO requests the Department find that the LDCs' current administration of the GSEP program is inconsistent with the "worst first" obligation in the DIMP.[139] Any changes the LDCs make to the Department's approved GSEP plan going forward should be driven by risk rather than convenience.

E. The Department has Broad Authority and Discretion to Administer the GSEP Program and Should Exercise this Authority to make GSEP More Affordable and Compliant with the Commonwealth's Climate Mandates.

The Legislature granted the Department broad authority and discretion to administer the GSEP program. The GSEP Statute gives the Department the authority to set the revenue cap.[140] The Legislature initially determined that "1.5 per cent of the gas company's most recent calendar

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137 49 C.F.R. § 192.1007(d).

138 Exhs. LDC-Rebuttal-1, at 75 n.41; ES-RJB-1, at 36.

139 *See* G.L. c. 164, § 145(c). The GSEP statute requires LDCs to prioritize GSEP projects to implement the DIMP. 2025 GSEP Filings – Procedural Memorandum, at 5

140 G.L. c. 164, § 145(f).

year total firm revenues" would serve as an appropriate revenue cap, but allowed adjustments above that threshold to "an amount determined by the department."[141] In 2019, the Department used its discretion to raise the revenue cap to 3.0 percent.[142] Just as changing circumstances enabled the Department to raise the revenue cap seven years ago, the necessity of complying with the Commonwealth's climate mandates, avoiding stranded assets, and alleviating increasing cost pressures on ratepayers warrants the Department's use of its authority to lower the GSEP cap back to 1.5 percent.

The Legislature provided broad discretion in the Department's standard of review for the GSEP plans. Section (d) of the GSEP statute directs the Department to review "the costs and benefits of the [LDC's] plan[s], including, but not limited to, impacts to ratepayers, reductions of lost and unaccounted for natural gas through a reduction in natural gas system leaks and improvements to public safety."[143] The statutory language "but not limited to" establishes the standard of review as an open-ended analysis, implying that the Department is best equipped to consider other factors that may impact the prudence of submitted GSEP plans. It follows that the Department has the statutory authority to consider policy developments that significantly impact natural gas ratepayers, such as recent climate-focused legislation and the GSEP Working Group's recommendations.

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141 *Id.*

142 *Unitil*, D.P.U. 18-GSEP-01, at 26–27 (the Department noted (relying on statements from the LDCs) "that a 3.0-percent GSEP cap would mitigate, if not eliminate, ongoing deferrals while balancing the bill impact to ratepayers over time and permitting the Company to complete its GSEP work within the established timeline." For most LDCs, deferrals have persisted at an unrelenting pace while ratepayers have continued to be squeezed.)

143 G.L. c. 164, § 145(d).

Relatedly, the Legislature amended the GSEP statute to specifically require analysis of the impact of GSEP on the Commonwealth's climate mandates, asserting that the Department must review the LDCs' interim GSEP targets "to ensure 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 chapter 21N of the general laws*."[144] Also, mindful of how the clean energy transition would impact natural gas ratepayers, the Legislature further amended the GSEP statute to require that any GSEP plan filed with the Department must now also include "a description of customer costs and benefits under the plan, including the costs of potential stranded assets and the benefits of avoiding financial exposure to such assets."[145] Accordingly, there is no doubt that the Legislature intended to extend broad deference to the Department to analyze the GSEP plans in the context of the energy transition. As a result, the Department should utilize its broad deference and implement the AGO's recommendations below, which include defining "stranded assets" and providing guidelines for stranded asset cost-benefit analysis, and by requiring LDCs to integrate GSEP plans into CCPs and other IEP efforts.

Further, Section (h) of the GSEP statute states that "[t]he department may promulgate rules and regulations … [and] may discontinue the replacement program and require a gas company to refund any costs charged to customers due to failure to substantially comply with a plan or failure to reasonably and prudently manage project costs."[146] This clause makes clear that the Department is responsible for enforcement of the GSEP program, and provides further discretionary powers the Department can use when the LDCs have failed to: (1) substantially comply with the GSEP

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144 St. 2024, c. 239, § 81 (emphasis added).

145 *Id*.

146 G.L. c. 164, § 145(h).

plan; or (2) prudently manage costs. Section (h) plainly puts the Department in charge of enforcement, and the Massachusetts Supreme Judicial Court has recently affirmed that courts must "give substantial deference to a reasonable interpretation of a statute by the administrative agency charged with its … enforcement."[147] With this authority and discretion, the Department should clarify the LDCs' evidentiary burden to both "prudently manage project costs" and "substantially comply with a plan."

In sum, the language of the GSEP statute grants the Department broad authority and discretion to administer the GSEP program and enforce compliance with the statutory requirements and rules promulgated by the Department. The AGO respectfully requests the Department exercise its statutory authority to (1) make the above findings, and (2) adopt the following recommendations to reduce cost burdens on ratepayers and align GSEP with the climate mandates.

III. RECOMMENDATIONS

A. The Department Should Gradually Lower the GSEP Cap Over the Next 3 Years to the Statutory Minimum of 1.5 Percent.

The AGO recommends the Department gradually lower the cap to the statutory minimum over 3 years.[148] To that end, the 2025 GSEP plans should be adjusted to institute a 2.5 percent cap, followed by a 2.0 percent cap for the 2026 GSEP plans, and finally to a 1.5 percent cap for the 2027 GSEP plans and all future GSEP plans. This recommendation is consistent with the AGO's comments in the GSEP Working Group Report.[149] In addition to lowering the GSEP cap, the AGO

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[147] *DiMasi v. Secretary of Commonwealth*, 491 Mass. 186, 191 (2023), quoting *Water Dep't of Fairhaven v. Department of Envtl. Protection*, 455 Mass. 740, 744 (2010).

[148] Exh. AG-DL-DM-1, at 48.

[149] GSEP Working Group Report and Recommendations, at 44–47.

recommends the Department deny recovery of carrying charges for any deferred amounts above the cap.

1. Gradually lowering the GSEP cap will reduce cost burdens on ratepayers and better align the GSEP program with the Commonwealth's climate mandates.

When the Legislature established the GSEP program in 2014, it balanced the incentive to invest in gas infrastructure (accelerated cost recovery) with a revenue cap to protect ratepayers.[150] As described in detail above, since 2019, the circumstances surrounding the GSEP program have changed significantly, and these changes warrant lowering the cap. Lowering the GSEP cap, however, will not be sufficient on its own to reduce costs; the Department must also make clear that spending over the cap will not be rewarded with concomitant carrying costs. Given the affordability crisis in the Commonwealth, and the likelihood that gas prices will continue to rise as the energy transition continues, it is critically important that the Department take steps to rein in LDC GSEP spending.

Lowering the GSEP cap forces the LDCs to consider less-expensive alternatives to replacement, outlined by the AGO above, by reducing the amount the LDCs can recover on an accelerated timeline.[151] Lowering the cap will also encourage LDCs to exercise greater discretion and focus on "worst first" pipe replacement. The LDCs should be prioritizing GSEP work based on risk, not upgrading all infrastructure where there is road paving with little to no regard for its

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[150] *NSTAR Gas*, D.P.U. 20-GREC-06, at 27–30 (affirming that the purpose of the GSEP cap is "to act as a balance on potential bill impacts on ratepayers").

[151] *See* Part II(B)(4), at 20 (The LDCs must lower GSEP costs by (1) decommissioning LPP and implementing NPAs, (2) targeted decommissioning of LPP that does not serve customers and is not necessary for system reliability, and (3) delaying replacement of LPP with a low risk score through repair or advanced monitoring until an NPA can be implemented.).

actual DIMP prioritization score. A lower cap will force the LDCs to focus replacement efforts on the greatest risks, such as actively leaking pipes.

Gradually lowering the GSEP cap over three years provides the LDCs with sufficient time to adjust their GSEP programs to include meaningful cost-reduction measures. Stepping down the cap may also provide LDCs with the opportunity to recover existing deferrals while decreasing overall GSEP spending.

2. The LDCs' arguments against lowering the GSEP cap are unsupported.

The LDCs' arguments against lowering the GSEP cap are unsupported by the record evidence. First, the LDCs argue that lowering the GSEP cap would jeopardize gas system safety and reliability.[152] As noted by the PHMSA Letter, GSEP "relates primarily to the ratemaking methods that the [LDCs] are authorized to use to recover the GSEP-related costs in rates."[153] In other words, GSEP is a financing mechanism, and the LDCs are legally obligated to maintain a safe and reliable system regardless of whether they receive accelerated cost recovery for their capital investments.[154] Lowering the cap would require the LDCs to move away from system-wide infrastructure upgrades and focus replacement efforts on the greatest risks.

Second, the LDCs argue that lowering the GSEP cap will increase customer bills in the long run because the LDCs will be forced to accrue large deferrals that accrue interest.[155] They

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152 Exh. LDC-Rebuttal-1, at 26–28.

153 PHMSA Letter, at 2.

154 G.L. c. 164, § 144 ("Grade 1 leaks require repair as immediately as possible and continuous action until the conditions are no longer hazardous."); 49 C.F.R. 192.703 ("(b) Each segment of pipeline that becomes unsafe must be replaced, repaired or removed from service; (c) Hazardous leaks must be repaired promptly."); 220 CMR 101.01 (stating every piping system in Massachusetts shall be constructed, operated, and maintained in compliance with Minimum Federal Safety Standards under 49 C.F.R. 192).

155 Exh. LDC-Rebuttal-1, at 30.

further argue that, when the GSEP program ends, the deferred amounts will result in rate shock once they're incorporated into distribution rates through a rate case proceeding.[156] Here, the LDCs appear to imply that they will continue spending at the same rate regardless of a cap. This shows a concerning disregard for regulatory process created by the GSEP Statute and the Department's regulatory authority. Furthermore, the LDCs seem to imply that they are entitled to accrue deferrals over the cap no matter how great. The GSEP Statute states that "[a]ny revenue requirement *approved by the Department* in excess of such cap may be deferred for recovery in the following year."[157] As discussed in Section II. E. above, the Department has the authority to set the GSEP cap and enforce compliance to ensure prudent management of costs. The AGO recommends the Department exercise this authority to lower the cap, deny carrying charges, and give the LDCs notice that imprudent spending above the cap will not be eligible for deferred recovery in future years.

Third, the LDCs argue that a lower cap will result in a longer GSEP timeline and more frequent rate cases.[158] Again, these arguments are predicated on the assumption that the LDCs will continue to spend at the same rate, replacing all LPP with new pipe. As the energy transition continues, and as the LDCs decommission LPP without replacement, the total costs of the GSEP program should decline. Additionally, the AGO has repeatedly argued that the costs of gas infrastructure improvements should be recovered in base rate cases.[159] Rate cases afford greater time for prudence review, allow the Department to consider LPP remediation in the context of all

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156 *Id.*

157 G.L. c. 164, § 145(f).

158 Exh. LDC-Rebuttal-1, 31–32.

159 Exh. AG-DL-DM-1, at 10–12; GSEP Working Group Report, at 44.

capital expenditures, and disincentivize overspending due to regulatory lag.[160] In the GSEP Working Group Report, the AGO recommended that the Legislature gradually phase out the GSEP program and end accelerated cost recovery completely in 2030. Absent a legislative change to that effect, the AGO maintains that the GSEP program should end when it reaches its statutory end date in 2034.[161]

Simply put, the GSEP cap is an accountability mechanism. Gradually lowering the cap will force LDCs to exercise greater discretion and make more prudent investments in the gas distribution system. A lower cap is key to reducing cost burdens on ratepayers and aligning the GSEP program with the Commonwealth's climate mandates.

B. The Department Should Require the LDCs to Resubmit the 2025 GSEP Plans to Reflect a 2.5 Percent Cap.

Pursuant to the recommendation that the Department begin lowering the GSEP cap, the AGO recommends that the Department require the LDCs to resubmit their 2025 GSEP plans to reflect a 2.5 percent cap. Because the LDCs have overinvested in system-wide infrastructure upgrades for far too long, the AGO encourages the Department to take immediate action to lower the GSEP cap, thereby discouraging excessive spending on new natural gas infrastructure and saving ratepayer dollars.

C. The Department Should Clarify the Evidentiary Burden for the LDCs to "Prudently Manage Project Costs."

The GSEP Statute charges the Department with ensuring that the LDCs incur only prudent costs. First, section (f) of the statute states that "the department shall investigate project costs within 6 months of submission and shall approve and reconcile the authorized rate factor, if

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160 Exh. AG-DL-DM-1, at 10–12.

161 G.L. c. 164, § 145(c) (stipulating a program end date with a target end date of "not more than 20 years of a gas company's initial plan").

necessary, upon a determination that the costs were reasonable and prudent."[162] Second, section (h) of the statute asserts that "[t]he department may discontinue the replacement program and require a gas company to refund any costs charged to customers due to . . . failure to reasonably and prudently manage project costs."[163] Accordingly, the AGO recommends that the Department clarify the evidentiary burden for "prudently manage[d] project costs" by: (1) requiring the LDCs to demonstrate that they are pursuing less costly means of addressing LPP (including NPA implementation, targeted decommissioning, and delay by way of repair and advanced monitoring until NPAs may be implemented); and (2) requiring that LDCs with deferred costs demonstrate an effort to recover those costs within the GSEP revenue cap so that the deferred values do not continue to balloon.

D. The Department Should Clarify the Evidentiary Burden for the LDCs to "Substantially Comply with a Plan."

The Legislature granted the Department significant authority to determine whether the LDCs substantially complied with their GSEP plans. Specifically, section (f) of the GSEP Statute, says "a gas company shall file [with the Department] final project documentation for projects completed in the prior year to demonstrate substantial compliance with the [GSEP] plan."[164] Additionally, section (h) of the statute gives the Department the authority to "discontinue the replacement program and require a gas company to refund any costs charged to customers due to failure to substantially comply with a plan."[165]

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[162] G.L. c. 164, § 145(f).

[163] G.L. c. 164, § 145(h).

[164] G.L. c. 164, § 145(f).

[165] G.L. c. 164, § 145(h).

In the 2024 GREC proceedings, the Department was "concerned with the number of projects that were approved by the Department and were not undertaken as well as the number of new projects that [the LDCs] included."[166] As a result, the LDCs must now produce: "(1) evidence to support its decision that any new projects should be prioritized over the Department-approved projects; (2) evidence as to whether any new projects displaced an approved project with a higher risk prioritization factor; and (3) where an approved project was canceled due to unforeseen circumstances, evidence that the new replacement project was selected based on appropriate risk prioritization or environmental justice considerations."[167]

The AGO recommends additional evidentiary requirements be included in the Department's "substantial compliance" analysis. Going forward, "substantial compliance" should require a showing that all new projects were selected based on risk, and they did not displace Department-approved GSEP projects with higher risk prioritization scores. The Department should make clear that, adding a multitude of unapproved projects to GSEP based on road paving and municipal works, absent evidence of actual LPP risk, will result in a finding that the LDC did not substantially comply with the approved GSEP plan.

E. The Department Should Define "Stranded Assets" and Provide Guidelines for Stranded Asset Cost-Benefit Analysis.

The LDCs are now required to include in their GSEP plans "a description of customer costs and benefits under the plan, including the costs of potential stranded assets and the benefits of avoiding exposure to such assets."[168] Before the next GSEP plans are filed, the AGO recommends

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166 *Unitil*, D.P.U. 24-GREC-01, at 32; *Berkshire,* D.P.U. 24-GREC-02, at 30; *National Grid,* D.P.U. 24-GREC-03, at 36; *Liberty*, D.P.U. 24-GREC-04, at 31; *EGMA*, D.P.U. 24-GREC-05, at 30-31; *NSTAR Gas*, D.P.U. 24-GREC-06, at 31.

167 *Id*.

168 St. 2024, c. 239, § 81.

that the Department: (1) establish a formal definition for stranded assets; and (2) offer guidance on the required stranded asset analysis.

The AGO recommends that, for purposes of the GSEP proceedings, the Department adopt the following definition of stranded assets: "A stranded asset is an asset that becomes unnecessary or redundant before the end of its nominal useful service life." This definition is consistent with the definition provided by National Grid's expert at the evidentiary hearing: "Stranded assets . . . still have the capacity to serve customers, but there [are not many] customers to serve."[169] Defining stranded assets will help ensure consistency across LDCs when the LDCs include the stranded asset cost-benefit analysis in future GSEP plans.

The AGO also recommends the Department provide guidance for the stranded asset cost-benefit analysis. For example, for each GSEP project that includes replacement of LPP with new pipe, the AGO recommends that the LDC provide: (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.

F. The Department Should Require LDCs to Integrate GSEP Plans Into CCPs and Other IEP Efforts.

The Department has acknowledged that "[a] robust, coordinated IEP process is vital to enable the Commonwealth's transition to its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective natural gas service; minimizing the burden on low-and moderate-income households as the transition proceeds; and facilitating a just workforce and energy

[169] Tr. Vol. 1, at 57–58.

infrastructure transition."[170] The AGO defines IEP as a process that considers overall building energy requirements and decarbonized options for meeting them, which necessarily involves major reforms to the Companies' capital planning processes.[171] Capital planning through the GSEP program is inherently pipe-centric, incentivizing the LDCs to rebuild and upgrade the gas distribution system. Even the required NPA analysis is still organized around the needs of the particular gas assets, influencing the timing, scope, geography, and feasibility of each project.[172] The IEP process must be centered around electrification as the primary pathway to achieve the Commonwealth's GHG limits and should consider alternative configurations of electrified or decarbonized heating technologies with a different scope or footprint.[173]

The Climate Compliance Plans ("CCPs"), which the LDCs must file with the Department on or before April 1, 2025,[174] should incorporate the Company's GSEP plans and LPP inventory. Immediate and long-term LPP remediation should influence the geography and timing of electrification and decarbonization efforts. Instead of relying solely on the GSEP's NPA analysis to avoid over-investment in gas infrastructure, GSEP should be a component of broader IEP planning. The IEP process should use the long-term GSEP plans to identify proposed gas capital investments and their timing; the LDCs and EDCs should prioritize customer outreach and

[170] *Future of Gas,* D.P.U. 20-80-D, at 22 (citing D.P.U. 20-80-B, at 5–6, 13–18, 87–88, 131) (Mar. 11, 2025).

[171] Exh. AG-DL-DM-1, at 50.

[172] *Id*. at 50–51.

[173] *Id*.; *Future of Gas*, D.P.U. 20-80-B, at 35 (stating that the Commonwealth's dominant building decarbonization strategy is electrification).

[174] *Future of Gas*, D.P.U. 20-80-B, at 134.

assistance in converting to NPAs to enable decommissioning of LPP before replacement becomes necessary.[175]

As the Commonwealth strives to meet its GHG emissions limits and sublimits, IEP is integral to all gas system planning and investment. GSEP—the capital investment tool used by the LDCs to upgrade aging gas infrastructure—does not exist in a vacuum.[176] By replacing aging gas infrastructure with electrified and decarbonized heating solutions before LPP remediation becomes necessary, the IEP process can proactively avoid substantial gas infrastructure costs through GSEP.

IV. CONCLUSION

Over the course of the 2025 GSEP proceedings, the Department, AGO and other stakeholders have developed a substantial evidentiary record. The AGO respectfully recommends the Department make the following findings:

- The GSEP program must be reconciled with climate-focused legislative and regulatory changes;
- The LDCs must reduce excessive and imprudent spending on new natural gas infrastructure;
- The LDCs' significant departure from their Department-approved GSEP plans undermines the regulatory process;
- The LDCs' administration of the GSEP program is inconsistent with the "worst-first" requirement of the gas distribution integrity management program ("DIMP"); and
- The Department has broad authority and discretion to administer the GSEP program and intends to exercise this authority to make the GSEP program more affordable and compliant with the Commonwealth's climate mandates.

[175] Exh. AG-DL-DM-1, at 51–54.

[176] Exh. AG-DL-DM-Surrebuttal, at 22.

In order to reduce cost burdens on ratepayers and align the GSEP program with the Commonwealth's climate mandates, the AGO further recommends the Department adopt the following changes to its administration of the GSEP program:

- The Department should gradually lower the GSEP cap over the next 3 years to the statutory minimum of 1.5 percent;
- The Department should require the LDCs to resubmit the 2025 GSEP plans to reflect a 2.5 percent cap;
- The Department should clarify the evidentiary burden for "prudent management of project costs";
- The Department should clarify the evidentiary burden for "substantial compliance with a plan";
- The Department should define "stranded assets" and provide guidelines for stranded asset cost-benefit analysis; and
- The Department should require LDCs to integrate GSEP plans into the CCPs and other IEP efforts.

Respectfully Submitted,

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Fitchburg Gas and Electric Light Company d/b/a Unitil	**D.P.U. 24-GSEP-01**
The Berkshire Gas Company	**D.P.U. 24-GSEP-02**
Boston Gas Company, d/b/a National Grid	**D.P.U. 24-GSEP-03**
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**
NSTAR Gas Company d/b/a Eversource Energy	**D.P.U. 24-GSEP-06**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in these proceedings in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston this 24th day of March, 2025.

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