

**COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES**

**FITCHBURG GAS AND ELECTRIC 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

JOINT DIRECT TESTIMONY OF

DAVID P. LITTELL and DEAN MURPHY

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

FEBRUARY 3, 2025

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1 **I. INTRODUCTION**

2 **Q. Mr. Littell, please state your full name and business address.**

3 A. My name is David P. Littell. My business address is 100 Middle Street, West Tower, 6th
4 Floor, Portland, ME 04101.

5 **Q. By whom are you employed?**

6 A. I am a Shareholder at Bernstein Shur Sawyer & Nelson (“Bernstein Shur”). Bernstein Shur
7 is a New England-based law firm that advises clients across the U.S. and around the world.

8 **Q. Please summarize your professional and educational background.**

9 A. I have worked in the regulatory sector for my entire professional career. I have worked as
10 an attorney and advisor in private practice for many years. I also had the honor of serving
11 as deputy commissioner and then commissioner of Maine’s Department of Environmental
12 Protection under Governor Baldacci as a member of his cabinet. I was at the Maine DEP
13 from 2003 to 2010. Subsequently, I served as a commissioner on the Maine Public Utilities
14 Commission from 2010 to 2015. I have advised many state commissions and energy and
15 environmental agencies subsequently. My background is presented in detail in Exhibit AG-
16 DL-DM-2.

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

18 A. My usual role in testifying before public utility regulatory agencies is in an advisory
19 capacity as a regulatory expert. In the Commonwealth, I have testified before the

1 Massachusetts Department of Public Utilities (“Department”) on various utility matters. I
2 testified on behalf of the Massachusetts Attorney General’s Office (“AGO”) in three of the
3 2022 GSEP reconciliation (“GREC”) dockets. I have also acted as a non-testimonial expert
4 in other DPU dockets as a consulting expert.

5 I have testified before the Maryland Public Service Commission on matters related to
6 Public Conference 44 and advised Maryland PSC staff, task groups, and the Commission
7 in the Public Conference 44 docket. I testified before the Public Utility Commission of
8 Ohio on performance-based regulation as part of its Power Forward Initiative. I also
9 assisted the Michigan Public Service Commission on performance-based regulation. Most
10 recently, I testified before the New Hampshire Public Utilities Commission on net metering
11 in Docket 22-060. This is not a comprehensive list. I have undertaken similar consulting
12 expert roles for several other commissions and energy offices in adjudicatory and non-
13 adjudicatory matters.

14 **Q. Dr. Murphy, please state your full name and business address.**

15 A. My name is Dean Murphy, and my business address is One Beacon Street, Suite 2600,
16 Boston, Massachusetts, 02108.

17 **Q. By whom are you employed?**

1 A. I am a Principal of The Brattle Group. The Brattle Group answers complex economic,
2 regulatory, and financial questions for corporations, law firms, and governments around
3 the world.

4 **Q. Please summarize your professional and educational background.**

5 A. I have thirty years of experience in economic consulting, focused on energy in the
6 electricity and natural gas sectors. My recent work has focused on decarbonizing both the
7 gas and electricity sectors, including interactions between the two sectors. I also have deep
8 experience in topics such as resource and investment planning, climate change policy and
9 analysis, valuation for contract disputes and asset transactions, competitive industry
10 structure and market behavior, and market rules and mechanics. I have examined these and
11 other matters from the perspectives of investor-owned and public electric utilities, state
12 agencies, regulators, independent energy producers and investors, industry groups,
13 consumers, and system operators.

14 I hold a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in
15 Engineering-Economic Systems, both from Stanford University, and a B.E.S. in Materials
16 Science and Engineering from Johns Hopkins University. My background, publications,
17 and prior testimony are described in my resume, which is included as Exh. AG-DL-DM-3.

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

1 A. I have testified before the New Hampshire Public Utilities Commissions, the Connecticut
2 Department of Public Utility Control, the New Jersey Department of Public Utilities, and
3 the Public Utilities Board of Manitoba. I have testified before committees of the state
4 legislatures in New Jersey, New York, and Pennsylvania, and have presented to advisory
5 committees to the Pennsylvania Department of Environmental Protection. I have also
6 testified before the United States Court of Federal Claims, the U.S. Bankruptcy Court (in
7 New Jersey and Southern District of New York), and the United States District Court
8 (Vermont). I sponsored testimony before the Department addressing the procurement of
9 offshore wind and hydroelectricity resources in the Section 83C and 83D proceedings
10 (D.P.U. 18-76 to 18-78, and D.P.U. 18-64 to 18-66); regarding Liberty Utility's petition for
11 approval of an RNG supply contract (D.P.U. 22-32), Boston Gas' petition for approval of
12 its forecast and supply plan (D.P.U. 22-149), and National Grid's, EGMA's, NSTAR's, and
13 Unitil's petition for approval of a multi-year natural gas supply agreement with
14 Constellation LNG, LLC (D.P.U. 24-25 to 28).

15 **Q. On whose behalf are you submitting testimony?**

16 A. We are testifying as independent experts on behalf of the AGO.

17 **Q. How is your testimony organized?**

18 A. Our testimony is organized as follows:

- Section II describes how the LDCs now use the GSEP statute as a tool to conduct system-wide infrastructure improvements.
- Section III addresses why GSEP must be reconciled with recent legislative mandates and decisions by the Department intended to transition the Commonwealth away from fossil fuels and towards renewable energy.
- Section IV demonstrates that, given the transition away from natural gas, GSEP is increasingly uneconomic and will result in stranded assets as well as unfair costs to ratepayers.
- Section V recommends that the GSEP cap should gradually be reduced to the statutory minimum of 1.5 percent.
- Section VI provides an overview of how GSEP inventory can be used as part of an integrated energy planning system that decentralizes natural gas from future building energy planning.

II. THE LDCs USE GSEP AS A TOOL TO CONDUCT SYSTEM-WIDE INFRASTRUCTURE IMPROVEMENTS.

Q. What is the GSEP program?

A. The Legislature passed the GSEP Statute in 2014 to address leaking natural gas infrastructure and improve safety and reliability in the Commonwealth’s gas distribution system.¹ The GSEP program has two parts²:

¹ *An Act Relative to Natural Gas Leaks*, c. 149 of the Acts of 2014, codified as G.L. c. 164, §§ 144 and 145.

² 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, the “LDCs” or singular “LDC”).

1 First, on or before October 31st of each year, each local gas distribution company (“LDC”)
2 may submit a GSEP plan to the Department that lists the company’s proposed GSEP
3 projects.³ GSEP projects involve the remediation of leak-prone pipe. The Department then
4 reviews and decides whether to approve or reject the LDC’s GSEP plan on a strict six-
5 month timeline.⁴

6 Second, after the proposed GSEP work is completed, the LDC files for cost recovery
7 through the GSEP Reconciliation mechanism (“GREC”).⁵ Again, the Department has only
8 six months to consider the prudence of work completed and respond to the LDCs’ cost
9 recovery requests. Under the GSEP statute, the LDCs are entitled to accelerated cost
10 recovery, subject to a cap. The cap shall not exceed “(i) 1.5 percent of the gas company’s
11 most recent calendar year total revenues . . . or (ii) an amount determined by the Department
12 that is greater than 1.5 percent of the gas company’s most recent calendar year total firm
13 revenues.”⁶ In 2019, the Department raised the revenue cap to 3 percent for all LDCs.⁷ The
14 Department’s decision to raise the revenue cap to 3 percent is discussed in greater detail in

³ G.L. c. 164, § 145(d).

⁴ G.L. c. 164, §§ 145(d) and (e).

⁵ G.L. c. 164, § 145(f).

⁶ *Id.*

⁷ *Unitil*, D.P.U. 18-GSEP-01, Order, at 26.

1 Section V below. The purpose of GSEP is to act as a financing mechanism outside of
2 traditional LDC rate cases to remediate leak-prone pipe on an accelerated timeline to
3 improve gas system safety and reliability.⁸

4 **Q. Without GSEP, are LDCs obligated to remediate leak-prone pipe?**

5 A. Yes. LDCs are required by law to address leak-prone pipe—Grade 1 leaks must be repaired
6 immediately, and all pipes must be maintained according to federal safety standards.⁹
7 GSEP did not create a new obligation to address leak-prone pipe. GSEP simply provided a
8 financing mechanism (accelerated cost recovery) to encourage the LDCs to fix leak prone
9 pipe faster. GSEP has worked to encourage substantial LDC investment. Put simply, the
10 GSEP program has incentivized significant spending due to its lack of traditional prudence
11 review and lack of financial cost controls.

⁸ *National Grid*, D.P.U. 18-GSEP-03, Order, at 21 (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 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.”).

⁹ 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.”); 22 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).

1 **Q. How do the LDCs administer the GSEP program?**

2 A. The LDCs administer GSEP in a way that takes a broad view of leak-prone pipe. First, the
3 LDCs treat GSEP as a system-wide capital improvement mechanism instead of a leak-
4 remediation tool. Second, the LDCs defer a substantial number of Department-approved
5 GSEP projects and instead complete many projects that were not approved by the
6 Department. Third, GSEP activity is frequently prompted by road paving moratoriums
7 instead of safety risk. We will discuss each of these three points in greater detail below.

8 **Q. Is GSEP work a significant area of capital expenditure for LDCs?¹⁰**

9 A. Yes. Instead of using GSEP as a leak-remediation tool, the LDCs use GSEP as a system-
10 wide improvement mechanism. Since 2015, the LDCs have reported GSEP capital
11 expenditures (“CapEx”) totaling about \$6.2 billion. The pace of GSEP CapEx spending
12 has increased by an average of 11.9 percent per year—from \$291 million per year in 2015
13 to \$892 million per year in 2025. In 2023, the LDCs’ financial statements reported total
14 CapEx of almost \$1.5 billion. This indicates that GSEP accounted for 54 percent of the

¹⁰ For this question, we compiled the LDC’s responses to D.P.U. 24-GSEP-01 through 06, Exhs. AG-1-2(b) and AG-1-26, which provided GSEP capital expenditures from 2019 to 2025. Note, some of the utilities did not provide data for 2024 (Liberty, EGMA) or 2019 (National Grid, Berkshire Gas) in response to these data requests. To fill in the 2024 values, we looked to the LDCs’ revenue requirement exhibits in the current 2024 GSEP dockets. For the historical missing values, we pulled capital expenditures from the utilities’ filings in prior GREC dockets, which go back to 2015.

LDCs total CapEx, on average across the LDCs. As shown in Figure 1 below, over the past five years, GSEP has accounted for 44 percent to 60 percent of the LDCs’ total capital investments.

Figure 1: GSEP CapEx as Percentage of Total CapEx¹¹

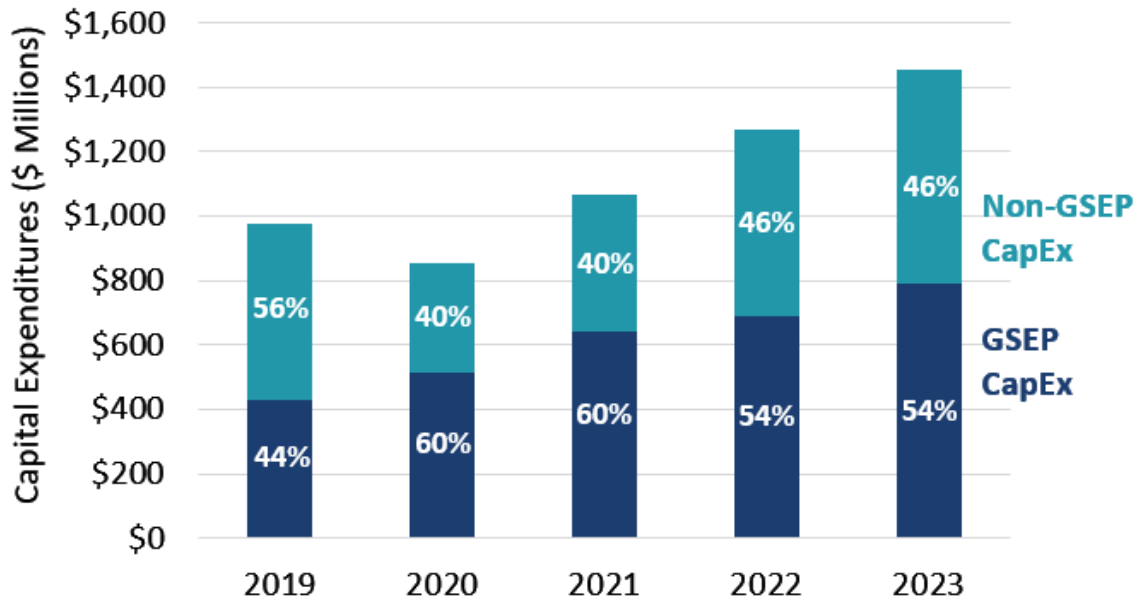


Figure 2 below shows each LDCs’ GSEP revenue requirements compared to total gas revenues over the same 5-year period. National Grid has the largest GSEP revenue requirement at \$432 million for the 2019–2023 period, whereas Berkshire Gas and Unitil

¹¹ See D.P.U. 24-GSEP-01 to 06, Exh. AG-DL-DM-4.

have the smallest total GSEP revenue requirements of \$12 million and \$16 million, respectively, for the 2019–2023 period.

Figure 2: GSEP Revenue Requirement (\$ Millions)

GREC Docket	Unitil	Berkshire Gas	National Grid	Liberty	EGMA	NSTAR Gas	<u>Annual Total</u>
2019	\$3.6	\$1.3	\$50.1	\$7.2	\$30.3	\$33.0	\$125
2020	\$1.7	\$2.2	\$74.6	\$4.3	\$33.9	\$40.4	\$157
2021	\$2.2	\$2.9	\$99.2	\$6.7	\$36.4	\$30.6	\$178
2022	\$3.5	\$3.4	\$82.6	\$14.1	\$25.3	\$46.1	\$175
2023	\$5.0	\$2.6	\$125.2	\$26.5	\$34.0	\$63.2	\$256
LDC Total (2019-2023)	\$16	\$12	\$432	\$59	\$160	\$213	\$892
Total Gas Revenues (2019-2023)	\$203	\$428	\$8,230	\$410	\$2,948	\$3,092	\$15,313
% GSEP	7.8%	2.9%	5.2%	14.3%	5.4%	6.9%	5.8%

Figures 1 and 2 demonstrate that GSEP has increasingly become the primary mechanism for capital expenditure and system improvement. This level of capital spending and investment for GSEP exceeds all other LDC CapEx and goes far beyond remediating immediate risks to safety caused by gas leaks.

Q. How do GSEP investments avoid ordinary prudence review typical for capital investments and system improvements in a rate case?

1 A. GSEP plans are considered and adjudicated on an expedited six-month timeline pursuant
2 to the GSEP statute.¹² The Department and other parties have limited time to consider the
3 prudence of proposed investments and the broader context of the LDCs' overall capital
4 expenditures. With the shortened time frame, it is especially difficult to complete a
5 meaningful prudence review. The accelerated time frame also makes it prohibitively
6 difficult to conduct non-pipe alternative ("NPA") analysis,¹³ as required by D.P.U. Orders
7 20-80-B and 20-80-C (known as the Future of Gas docket).¹⁴

8 Without GSEP, the costs of remediating leak-prone pipe would be recovered in base
9 distribution rate cases. Indeed, base distribution rate cases have several advantages over
10 GREC proceedings because they: (1) afford more time for prudence review; (2) allow the
11 Department to consider leak remediation in the broader context of all capital expenditures,
12 and (3) necessarily involve regulatory lag, which disincentivizes overspending.

13 Regulatory lag occurs when an LDC repairs leak prone pipe and carries the costs of
14 construction until its next base distribution rate case. The delay between expending the
15 costs and recovering them disincentivizes excessive overspending in the near term.

¹² G.L. c. 164, § 145(d) and (e).

¹³ See Section VI for a longer discussion of long-term NPA analysis.

¹⁴ *Future of Gas*, D.P.U. 20-80-B, Order (Dec. 6, 2023); *Future of Gas*, D.P.U. 20-80-C, Order (Apr. 2, 2024)

1 Accelerated cost recovery under GSEP, on the other hand, *incentivizes* the LDCs to make
2 system improvements because they can quickly recover the costs of construction and
3 charge interest on carry over expenses in excess of the cap. Once costs are approved in the
4 GREC six-month reviews, the LDCs are entitled to carrying costs in the form of interest.
5 The accelerated cost recovery mechanism combined with the shortened timeline for
6 prudence review has created a low-risk and high probability of payoff with carrying costs
7 for LDCs. Through the GSEP program, the LDCs make major capital investments and
8 recover significant costs in an accelerated manner that does not provide sufficient time for
9 any comprehensive prudence review.

10 **Q. Do the LDCs typically complete all the projects that were approved by the**
11 **Department in their GSEP plans?**

12 A. No. The approved GSEP plans provide only partial insight into the actual work ultimately
13 undertaken by the LDCs. In the 2024 GREC dockets, each LDC completed some
14 Department-approved projects, as well as some new projects that were not reviewed or
15 approved by the Department. For example, Unitil did not deviate much from its
16 Department-approved GSEP plans—completing 14 out of 18 projects in its GSEP plan,
17 deferring 4 projects, and adding 2 unreviewed projects.¹⁵ Conversely, NSTAR Gas deviated
18 substantially from its GSEP plans, which had been litigated, reviewed, and approved by

¹⁵ Unitil, D.P.U. 24-GREC-01, Exh. Unitil-CLTB-1, at 8–10 (Revised).

1 the Department. Specifically, NSTAR Gas completed only 132 out of 279, or 47.3 percent,
2 of projects in its GSEP plan, deferred 147 of its approved projects, and added 265 projects
3 that were not included in the approved GSEP Plan.¹⁶ In fact, NSTAR Gas added almost as
4 many unreviewed projects (265) as the total number that was originally proposed in its
5 GSEP plan (279).¹⁷ This significant departure from the Department-approved GSEP plan
6 demonstrates a massive disregard for the GSEP process. Figure 3 below shows the extent
7 to which each LDC complied with their respective 2023 GSEP plan based on 2024 GREC
8 data:

¹⁶ NSTAR, D.P.U. 24-GREC-06, Exh. AG-2-4, Att. AG-2-4(a).

¹⁷ *Id.*

1 *Figure 3: LDC Implementation of 2023 Proposed GSEP Plans*¹⁸

2023 GSEP	Unitil ¹⁹	Berkshire Gas ²⁰	National Grid ²¹	Liberty ²²	EGMA ²³	NSTAR Gas ²⁴
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%)

2 As shown above in Figure 3, the total number of unreviewed new GSEP projects completed
3 in 2023—those not on the 2023 GSEP Plans—exceeded the number of Department-

¹⁸ This comparison of each LDCs’ 2023 GSEP plan and 2024 GREC filings is substantially similar to the information submitted by the AGO in the 2024 GREC dockets. The data have been confirmed and, where appropriate, revised to account for duplicate projects and possible minor transcription errors. These data, as presented here, leads to the same conclusion as presented by the AGO in the 2024 GREC dockets.

¹⁹ *Unitil*, D.P.U. 24-GREC-01, Exh. Unitil-CLTB-1, at 8–10 (Revised).

²⁰ *Berkshire Gas*, D.P.U. 24-GREC-02, Exhs. BGC-JP-3, at 1; AG-2-2, Att. 2-2.

²¹ *National Grid*, D.P.U. 24-GREC-03, Exh. AG-2-3, Att. AG-2-3.

²² *Liberty*, D.P.U. 24-GREC-04, Exh. LU-NMW-1, at 6–7.

²³ *EGMA*, D.P.U. 24-GREC-05, Exhs. AG-2-4, Att. AG-2-4(a); AG-2-6, Att. AG-2-6.

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

1 approved GSEP projects for Berkshire Gas (61 percent of projects completed were new),
2 National Grid (82 percent), EGMA (60 percent), and NSTAR Gas (67 percent). Although
3 some flexibility is needed for LDCs to defer projects where implementation issues arise,
4 the pattern here goes far beyond reasonable flexibility. This illustrates our point that GSEP
5 is now being used as a general capital funding mechanism. It appears that, rather than
6 focusing on remediating gas leaks, at least four of the LDCs are shifting GSEP funds to
7 projects that fit their capital work plans in an effort to upgrade their gas systems.

8 **Q. How do paving moratoriums and other public works projects impact the LDCs' GSEP**
9 **plans?**

10 A. Roadwork, paving moratoriums, and other public works projects significantly impact
11 GSEP activity. LDCs frequently undertake new unreviewed GSEP projects based on public
12 works schedules and defer Department-approved GSEP projects in response to paving
13 projects. For example, EGMA stated: "If the Company is notified by a municipality that a
14 paving project is planned on a street, that is not on the Department-approved list, where
15 cast iron, bare steel, or unprotected coated steel facilities exist, the Company will develop
16 and schedule a GSEP project provided the municipality agrees to allow construction prior
17 to paving. In this event, the project will replace or defer a project or projects on the
18 Department-approved list"²⁵ In other words, projects that were reviewed and approved by

²⁵ EGMA, D.P.U. 24-GSEP-05, Exh. AG-1-22.

1 the Department based on their risk to public safety or potential to leak are then deferred in
2 response to roadwork plans in a different part of the distribution system.

3 **III. GSEP MUST BE RECONCILED WITH CLIMATE MANDATES AND THE D.P.U.**
4 **20-80 ORDERS**

5 **Q. Have circumstances changed since the GSEP statute was passed in 2014?**

6 A. Yes. Since 2014, the Commonwealth has taken clear and decisive steps to move away from
7 greenhouse gas emitting fuels and towards renewable energy. Both the Legislature and the
8 Department have made landmark decisions aimed at transitioning Massachusetts to a
9 system largely powered by renewable electricity:

- 10 • **Chapter 21N (2021):** In 2021, the Legislature passed *An Act Creating a Next*
11 *Generation Roadmap for Massachusetts Climate Policy*, which established a statutory
12 mandate of net zero GHG emissions by 2050 and at least a 50 percent reduction by
13 2030.²⁶
- 14 • **2025 and 2030 CECP (2022):** Chapter 21N required the Executive Office of Energy
15 and Environmental Affairs (“EEA”) to develop a Clean Energy and Climate Plan
16 (“CECP”) every five years to ensure the GHG emissions mandates are met. The 2025
17 and 2030 CECP adopted by EEA mandates that the building sector must achieve at
18 least a 47 percent reduction from 1990 GHG emission levels by 2030 and 93 percent
19 reduction by 2050.²⁷
- 20 • **D.P.U. 20-80-B Order (2023):** The Department’s landmark Order in the future of gas
21 docket established that LDCs may no longer conduct “business as usual” and instead

²⁶ G.L. c. 21N, §§ 3, 3A, and 4.

²⁷ EEA, 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>.

1 must play an active role in achieving the Commonwealth’s climate goals.²⁸ Importantly,
2 the Order identifies electrification and thermal network technologies as a primary
3 means to decarbonize and requires LDCs to conduct an NPA analysis before investing
4 in natural gas infrastructure.²⁹

- 5 • **D.P.U. 20-80-C Order (2024):** In response to the LDCs’ Joint Motion for Clarification,
6 the Department made clear it “did not carve out GSEP or any other project category as
7 exempt from the NPA analysis requirement in its Order and we will not do so as a
8 clarification here.”³⁰
- 9 • **An Act Driving Clean Energy and Offshore Wind (2022):** In addition to promoting
10 offshore wind as an alternative to fossil fuels, *An Act Driving Clean Energy and Offshore*
11 *Wind* created the GSEP Working Group.³¹ The GSEP Working Group was tasked with
12 preparing a report for the Legislature with suggestions to better align GSEP with the
13 Commonwealth’s climate mandates. This legislation also amended the GSEP statute by
14 (1) requiring LDCs to consider including the use of advanced leak repair technology to
15 repair any existing leak-prone pipe; and (2) allowing LDCs to replace GSEP-eligible
16 gas infrastructure with utility-scale non-emitting renewable thermal energy
17 infrastructure, such as geothermal systems.³²
- 18 • **GSEP Working Group Report (2024):** The GSEP working group sent its final report
19 and recommendations to the Legislature on January 31, 2024.³³ Although the report did

²⁸ *Future of Gas*, D.P.U. 20-80-B, Order, at 18 (“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.”).

²⁹ *Id.* at 98.

³⁰ *Future of Gas*, D.P.U. 20-80-C, Order, at 21 (“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.”).

³¹ St. 2022, c. 179.

³² St. 2022, c. 179, § 58.

³³ GSEP Working Group Report and Recommendations (Jan. 31, 2024), available at: <https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act>.

1 not provide full consensus among members, it provided a list of proposed policy
2 changes and comments concerning each proposed change. In the report the AGO, along
3 with the National Consumer Law Center, recommended terminating expedited rate
4 treatment for GSEP-related costs of natural gas infrastructure in favor of recovery of
5 such costs by LDCs in base rate cases.³⁴ Eight working group members supported the
6 recommendation, which included a gradual reduction to the GSEP cap between 2024
7 and 2030.³⁵

- 8 • **Revisions to the GSEP Statute (2024):** The Legislature just recently made key
9 revisions to the GSEP statute. First, the Department must now review the LDCs’ interim
10 GSEP targets “to ensure each gas company is meeting the appropriate pace to reduce
11 the leak rate in a safe and timely manner and *comply with the limits and sublimits*
12 *established pursuant to chapter 21N of the general laws.*”³⁶ Second, the GSEP plans
13 must now include “a description of customer costs and benefits under the plan,
14 including the costs of potential stranded assets and the benefits of avoiding financial
15 exposure to such assets.”³⁷ Third, the original statutory language of “eligible
16 infrastructure replacement” was replaced with “eligible infrastructure measure,”
17 thereby emphasizing the fact that pipe-for-pipe replacement should not be the only or
18 default means of remediating leak-prone pipe.³⁸ These GSEP Statute amendments in
19 2024 will be referred to as the “GSEP Statute (2024).”

³⁴ *Id.* at 44–47.

³⁵ *Id.* at 47 (Roll Call Vote on AGO phased-out approach: 8 yes, 7 no, and 4 abstain. Yes - AGO, Senator Barrett, LEAN, NCLC, PowerOptions, HEET, Buonocore, CLF. No – Wakefield Municipal, USW, Berkshire Gas, EGMA, Liberty Utilities, National Grid, Unitil. Abstain – DOER, DPU, MassDEP, Representative Roy. Note: AGO and NCLC do not support expanding accelerated cost recovery to non-pipe alternatives.)

³⁶ St. 2024, c. 239, § 81 (emphasis added).

³⁷ *Id.*

³⁸ *Id.*

1 In its September 13, 2024 Procedural Memorandum, the Department asked the LDCs to
2 provide testimony and exhibits in response to several questions.³⁹ Question (b) asked
3 whether circumstances have changed since the Department adopted the existing 3.0 percent
4 revenue cap in 2019, in D.P.U. 18-GSEP-03.⁴⁰ The legislative and policy developments
5 listed above are all clearly circumstances that have changed, which justify (or in the case
6 of statutory changes, require) the Department re-evaluating how it regulates the GSEP and
7 GREC dockets.

8 **Q. Is GSEP exempt from the climate mandates or D.P.U. 20-80 Orders?**

9 A. No. As discussed above, the Department explicitly stated that GSEP is not exempt from the
10 obligations established by the D.P.U. 20-80-B Order. GSEP does not exist in a vacuum
11 independent of other statutes. The LDCs must continue to address leaks that threaten safety
12 and reliability, but they must do so in a prudent manner that will achieve the Chapter 21N
13 and CECP emission reductions established by EEA. As a practical matter, this means the
14 LDCs must now strategically minimize investment in natural gas infrastructure while
15 ensuring public safety and reliability are protected.

³⁹ D.P.U. 24-GSEP-01 through 24-GSEP-06, 2025 GSEP Filing - Procedural Memorandum
(Sept 13, 2024).

⁴⁰ *Id.* at 4.

1 In a joint response to the Department’s Procedural Memorandum, the LDCs argued that
2 “the Department has *already* harmonized Section 145 and Chapter 21N, by incorporating
3 Chapter 21N into its standard of review for GSEP.”⁴¹ On the contrary, the Department has
4 not substantially altered its method of review for the GSEPs since raising the cap in (and
5 after) 2019. In the 2024 GSEP dockets, the Department has an opportunity to reconcile
6 GSEP with the climate mandates, especially in light of the recent changes to the GSEP
7 Statute (2024), which mandate compliance with the 21N sublimits for emissions
8 reductions. Unfortunately, the 2025 GSEP plans do little to reconcile the ongoing capital
9 upgrades with 21N sublimits for the building sector. These are largely business-as-usual
10 GSEP plans.

11 **Q. How does GSEP impact GHG emissions?**

12 A. GSEP helps to reduce GHG emissions modestly by remediating pipes that leak methane
13 into the atmosphere. Lost and unaccounted for gas (“LAUF”) is a measure of the difference
14 between the amount of natural gas that enters the LDC’s distribution system, and the
15 amount metered to customers. Upgrading leaking pipe should tend to reduce LAUF. Since
16 GSEP work addresses leak-prone pipe, it is reasonable to assume that the amount of each
17 LDCs’ LAUF should decrease over time. Curiously, EGMA reports that its LAUF

⁴¹ D.P.U. 24-GSEP-01 through 24-GSEP-06, Exh. LDC-1, at 9.

1 percentage increased from 1.46 percent in 2019 to 2.88 percent in 2023.⁴² Similarly,
2 NSTAR Gas reports that its LAUF percentage increased from 1.35 percent in 2019 to 2.36
3 percent in 2023.⁴³ National Grid also reported an increase in its LAUF percentage for
4 Boston Gas Company but not for Colonial Gas Company.⁴⁴ The LDCs have not explained
5 why their LAUF percentage increased despite years of GSEP work.

6 Moreover, if LDCs reduce GHG emissions in the gas distribution sector solely through
7 reduction of LAUF (Scope 1 emissions), the Commonwealth will not reach its net-zero
8 mandate. The bigger driver of success or failure for the Commonwealth in meeting Chapter
9 21N's requirements are the indirect GHG emissions from the LDCs' product end-use
10 (Scope 3 emissions). LDCs must consider their indirect GHG emissions in the form of
11 buildings sector emissions, which includes emissions attributable to the heating and
12 cooling of commercial and residential buildings (Scope 3 emissions). In other words, LDCs
13 must also consider emissions attributable to natural gas throughput and end-use, not just
14 gas leaks.

15 The buildings sector contributes significantly more GHG emissions to the atmosphere than
16 the distribution sector. According to EEA's 2025 and 2030 CECP, the distribution sector

⁴² *EGMA*, D.P.U. 24-GSEP-05, Exh. AG-1-8.

⁴³ *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. AG-1-8.

⁴⁴ *National Grid*, D.P.U. 24-GSEP-03, Exh. AG-1-8.

1 must reduce emissions from 0.6 MMTCO₂e in 2020 to 0.4 MMTCO₂e in 2030.⁴⁵ The
2 buildings sector, on the other hand, must reduce emissions from 19.5 MMTCO₂e in 2020
3 to 12.5 MMTCO₂e in 2030.⁴⁶

4 Addressing GHG emissions in the building sector is critical to the Commonwealth's
5 success in achieving the climate mandates, and these 2025 GSEP plans do not meaningfully
6 reduce those emissions. As an example, in 2023 (the last year of data provided), EGMA
7 calculates that its gas sales to both residential and commercial and industrial customers
8 resulted in 2.81 MMTCO₂e.⁴⁷ EGMA estimates that 0.002 MMTCO₂e (or 1,700 MT CO₂e)
9 will be avoided by its proposed 2025 GSEP projects, which amounts to a 5.9 percent
10 reduction in its GHG emissions attributable to gas leaks, but only the equivalent of a 0.06
11 percent reduction in the building sector emissions created as Scope 3 emissions from their
12 gas sales.⁴⁸ To effectively meet Massachusetts' climate mandates, the Commonwealth, with
13 the LDCs active cooperation, must reduce natural gas throughput and emissions from the
14 building sector.

⁴⁵ EEA, Clean Energy and Climate Plan for 2025 and 2030, at 75.

⁴⁶ *Id.*, at 52.

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

⁴⁸ EGMA, D.P.U. 24-GSEP-05, Exh. AG-1-8, AG-1-9, Att. AG-1-9.

1 **Q. Have the LDCs successfully implemented NPA analysis in the GSEPs since D.P.U. 20-**
2 **80-C?**

3 A. No. The LDCs have not meaningfully implemented NPA analysis into their GSEP
4 programs. The Department's Orders in D.P.U. 20-80-B and 20-80-C require the LDCs to
5 implement interim NPA guidelines immediately while also working to develop a
6 permanent, standardized NPA process.⁴⁹

7 Since the LDCs' adopted an interim NPA analysis for GSEP projects, the overwhelming
8 majority of projects have been excluded from NPA consideration. The interim LDC
9 policies provide multiple NPA exclusions—reasons why a GSEP project may not, in the
10 LDC's opinion, qualify for NPA consideration (much less being found preferable and
11 implemented, once considered). For example, Berkshire Gas lists eight "technical
12 exclusions" that excuse GSEP projects from NPA analysis, including: (1) Construction
13 Imminent (Highway/Municipal); (2) Construction Imminent (Active Corrosion); (3) Threat
14 to Public Safety (Significantly Reduces Ability to Reliably Provide Gas Service); (4)
15 Threat to Public Safety (Eliminates Gas Service to Downstream/Out-of-Scope Customers);
16 (5) High Customer Saturation Along Main (20 or more gas services); (6) No Main
17 Installation (Abandonment / Upgrading); (7) Complete with Related Project on Street (GSEP
18 and System Betterment Combination); and (8) Project Dependent. These exclusions

⁴⁹ *Future of Gas*, D.P.U. 20-80-B, Order, at 15; *Future of Gas*, D.P.U. 20-80-C, Order, at 24.

1 removed 98 percent of Berkshire GSEP projects from NPA consideration, before getting to
2 the NPA benefit cost analysis (BCA) step.⁵⁰

3 The result is similar for five of the six LDCs, who each exclude 97 percent or more of their
4 GSEP projects; the sixth excludes about 60 percent. Figure 4 below shows the percentage
5 of GSEP projects excluded from NPA analysis for each LDC:

⁵⁰ *Berkshire Gas*, D.P.U. 24-GSEP-02, Exh. AG-1-28.

1

Figure 4: GSEP NPA Evaluation Summary⁵¹

	Unitil ⁵²	Berkshire Gas ⁵³	National Grid ⁵⁴	Liberty ⁵⁵	EGMA ⁵⁶	NSTAR Gas ⁵⁷	All Utilities
# excluded potential NPA projects / # total projects	8/8 (100%)	55/56 (98%)	109/186 (58.6%)	9/9 (100%)	96/97 (99%)	189/190 (99%)	466/546 (85.3%)
Excluded NPA project costs / total project costs	\$13.1M/ \$13.1M (100%)	\$21.0M/ \$21.2M (99.1%)	\$194.5M/ \$289.2M (67.3%)	\$10.5M/ \$10.5M (100%)	\$124.3M/ \$124.7M (99.7%)	\$103.2M/ \$103.7M (99.5%)	\$466.6M/ \$562.4M (83.0%)
Excluded potential NPA project main replacement miles / total project main replacement miles	5.5/5.5 (100%)	12.4/12.5 (99.2%)	43.1/72.4 (59.5%)	8.0/8.0 (100%)	53.0/53.2 (99.6%)	59.7/60.0 (99.5%)	181.7/211.6 (85.9%)
# excluded potential NPA projects services / # total project services	618/618 (100%)	792/793 (99.9%)	N/A	769/769 (100%)	N/A	N/A	2,179/2,180 (99%)

⁵¹ This data was presented to the NPA Working Group Meeting #4 on January 15, 2024. The figure presented to the working group included data for Boson Gas Company but not Colonial Gas Company. This figure has been updated to include both Boston Gas Company and Colonial Gas Company data for National Grid.

⁵² *Unitil*, D.P.U. 24-GSEP-01, Exh. Unitil-RKCL-5, Attachment B (values listed for Unitil’s main mileage are from “Install Footage”).

⁵³ *Berkshire Gas*, D.P.U. 24-GSEP-02, Exh. BGC-JP-4.

⁵⁴ *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-4 (values listed for Boston Gas’s main mileage is from “GSEP mileage”).

⁵⁵ *Liberty*, D.P.U. 24-GSEP-04, Exh. LU-NMW-2, Appendix D (values listed for Liberty’s services are the number of “service replacements” and “service transfers”).

⁵⁶ *EGMA*, D.P.U. 24-GSEP-05, Exh. EGMA-RJB-1, Appendix A (main mileage derived from “Installation Footage” (adjusted to miles)).

⁵⁷ *NSTAR Gas*, D.P.U. 24-GSEP-06, Exh. ES-RJB-1, Appendix A (main mileage derived from “Installation Footage” (adjusted to miles)).

1 For GSEP project costs, the impact of the exclusion policies is even more marked: all six
2 exclude a larger share of dollars than project numbers, with five excluding 99 percent of
3 GSEP project dollars from NPA consideration, and the sixth excluding 67 percent.

4 **Q. How should the Department and LDCs reconcile GSEP with climate mandates and**
5 **departure from “business as usual”?**

6 A. The Department’s landmark Orders in D.P.U. 20-80 establish that the LDCs may no longer
7 operate under “business-as-usual” (“BAU”). They must undertake an active role in
8 achieving the Commonwealth’s climate goals.⁵⁸ This means that the 2025 GSEP plans, in
9 which LDCs continue with BAU to upgrade gas infrastructure system-wide, should not
10 continue to be implemented as a full-blown gas distribution system capital upgrade scheme
11 as has been the case as GSEP upgrades and funding has expanded during the last five years.
12 The LDCs’ prior GSEP path, which is BAU, locks-in GHG emissions through an overbuilt
13 gas system, and actively stymies the Commonwealth’s efforts to meet its climate mandates.
14 It also increases customer costs and potential stranded costs.

15 The GSEP program must be reconciled with the Commonwealth’s climate mandates by
16 bringing it back to remediation of leaking gas plant. Instead of being a program that

⁵⁸ *Future of Gas*, D.P.U. 20-80-B, Order, at 18 (“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.”).

1 upgrades much of the gas distribution system at a pace dictated by paving moratoriums,
2 GSEP should be driven predominantly by the threat that leaking pipe poses to the public
3 and to our climate. This can be achieved by focusing the GSEP process primarily on
4 remaining cast-iron pipes and other gas plant that are actually leaking or at imminent risk,
5 looking first to alternative solutions (such as electrification) that would allow
6 decommissioning of these gas assets, and repairing or replacing them with new pipe only
7 as a last resort. Pipe that is not at imminent risk of leaking and creating safety concerns
8 should not be replaced with gas pipe; it is a candidate for decarbonized solutions.

9 As discussed in greater detail in Section V, lowering the GSEP cap gradually to the original
10 level of 1.5 percent is consistent with a leaner GSEP program and would require the LDCs
11 to prioritize high-risk projects. A lower GSEP cap would also necessarily mean fewer
12 GSEP funded upgrades that would become uneconomic stranded assets in the future.

13 Finally, the LDCs should work with greater diligence to implement Integrated Energy
14 Planning (“IEP”) and NPA analysis as a part of the GSEP project planning, with the goal
15 of replacing problematic gas assets with alternative, decarbonized energy infrastructure.
16 IEP (discussed below) and NPA analyses dovetail with lowering the GSEP revenue cap.
17 Replacing leak-prone assets with alternative, decarbonized infrastructure will often be less
18 costly in the long run and will involve lower emissions. The alternative infrastructure will

1 continue to be useful for its full engineering life, whereas new gas infrastructure will be at
2 high risk of becoming unused, underused, and uneconomic.

3 **IV. GSEP IS INCREASINGLY UNECONOMIC AND WILL RESULT IN STRANDED**
4 **ASSETS**

5 **Q. Are the costs of GSEP pipe replacement increasing?**

6 A. Yes. Since 2014, the LDCs have reported GSEP capital expenditures totaling \$6.2 billion.⁵⁹
7 GSEP costs have been increasing and are projected to further increase due to new contracts,
8 inflation, and construction cost factors. For example, National Grid’s current average cost
9 for leak-prone pipe replacement is \$3.3 million per mile.⁶⁰ In its Boston Gas service
10 territory, the cost per mile to replace leak-prone pipe has increased by 49 percent over the
11 five-year period from 2018 to 2023.⁶¹ For EGMA, the cost per mile to replace leak-prone
12 pipe has increased by approximately 8 percent between 2018 and 2023, to \$2 million per
13 mile.⁶² Liberty explains that, as GSEP work continues, the replacement projects have
14 become more complicated: “Liberty anticipates that progress in successfully completing
15 these upcoming GSEP projects will be slower, will require the allocation of more resources,

⁵⁹ Section II involves a longer discussion of capex per LDC.

⁶⁰ *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-2, at 43.

⁶¹ *Id.* at Exh. NG-GPP-1, at 15.

⁶² *EGMA*, D.P.U. 24-GREC-05, Exhs. AG-1-4; EGMA-RJB-2.

1 and will ultimately be more expensive to complete.”⁶³ GSEP complexity is increasing, and
2 costs are rising faster than other costs in the Commonwealth economy.

3 **Q. Do the LDCs have a large inventory of leak-prone pipe remaining?**

4 A. Yes. Each LDC has an inventory of leak-prone mains and services in need of remediation.
5 This inventory includes both identified leaking pipes and plant, plus much of the remaining
6 LDC plant that is assumed to be leak prone based on its age, material, and other factors.

7 Since the inception of the GSEP program, the LDCs have used replacement through
8 upgraded gas infrastructure as the primary means of remediating leak-prone pipe.
9 Replacement made sense when the Commonwealth reasonably assumed that natural gas
10 would be the predominant energy source for residents and businesses for the indefinite
11 future. Now that the Commonwealth has taken clear and decisive steps to shift away from
12 greenhouse gas emitting (largely fossil) fuels and towards electrification and renewable
13 energy, system-wide upgrades to natural gas infrastructure make increasingly less
14 economic sense.

15 National Grid identified 2,486 miles of leak-prone main for Boston Gas Company.⁶⁴ Even
16 if the costs of replacement remained the same going forward, the cost to replace all 2,486

⁶³ *Liberty*, D.P.U. 24-GSEP-04, Exh. LU-NMW-1, at 6.

⁶⁴ *National Grid*, D.P.U. 24-GSEP-03, Exh. NG-GPP-2, at 15.

1 miles would be over \$8 billion.⁶⁵ This figure does not include the cost to replace 86,817
2 services⁶⁶ nor future cost increases attributable to inflation, gas project cost escalation
3 beyond inflation, new contracts, and other factors cited by the LDCs.

4 **Q. How much will GSEP cost if the program continues to focus on pipe replacement?**

5 A. If GSEP continues as a predominantly pipe-replacement program, a conservative estimate
6 of remaining GSEP investment costs exceeds \$13.7 billion (this figure reflects only the
7 direct costs invested by the LDCs; the costs they will seek to recover from ratepayers will
8 be much higher since they include a return on the investments and carrying charges in the
9 form of interest). To determine this figure, we first projected the remaining GSEP costs
10 based on the LDCs' reported cost per mile of main replacement and the remaining miles of
11 GSEP eligible pipe, accounting for the expected end-dates of each LDCs' GSEP programs.
12 We escalated those costs at the assumed inflation rate of 2 percent. Where the LDCs did
13 not provide year-by-year forecasts of miles to be replaced until the end of their program,
14 we distributed the remaining miles of GSEP-eligible pipe uniformly across the remaining
15 years of their program.

⁶⁵ *Id.* (2,486 miles times \$3.3 million is \$8.2 billion).

⁶⁶ *Id.* at 16.

Figure 5 below, which shows a *remaining* statewide GSEP capital investment cost of \$13.7 billion, is exceptionally conservative because this analysis escalates GSEP investment cost per mile at only 2 percent to track assumed inflation, rather than the much higher escalation rates experienced recently. By comparison, the recent historic growth rate of GSEP capital expenditures has averaged 11.9 percent per year.

Figure 5: Remaining Statewide GSEP Cost

	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

It is simply uneconomic to invest an additional \$13.7 billion into natural gas infrastructure while, at the same time, the Commonwealth actively works to meet the required net-zero GHG emissions by 2050; to avoid unreasonable costs, the LDCs should adopt a process to cost-effectively decommission much of their natural gas infrastructure over the upcoming two decades. (It is also worth noting that the LDCs continue to make non-GSEP capital

1 investments of nearly equal magnitude.) As the Commonwealth transitions toward
2 electrification, GSEP investments proposed by the LDCs are likely to become stranded
3 assets.

4 **Q. Why are GSEP investments likely to become stranded assets?**

5 A. GSEP investments are likely to become stranded assets that waste ratepayer dollars and
6 exacerbate the costs of the energy transition. For purposes of our testimony, we define a
7 stranded asset as an asset that becomes unnecessary before the end of its nominal useful
8 service life, which can be thought of as its engineering life. GSEP investments are likely
9 to become stranded assets as the Commonwealth necessarily reduces natural gas
10 throughput and usage pursuant to Chapter 21N. Some LDCs have acknowledged this shift
11 is inevitable. National Grid, for example, stated that, “The Company recognizes that the
12 Commonwealth’s pathway to net zero implies substantial declines in both gas volumes and
13 customer counts.”⁶⁷

14 Plastic natural gas pipes are long-lived assets with useful lives of approximately 40 years.⁶⁸

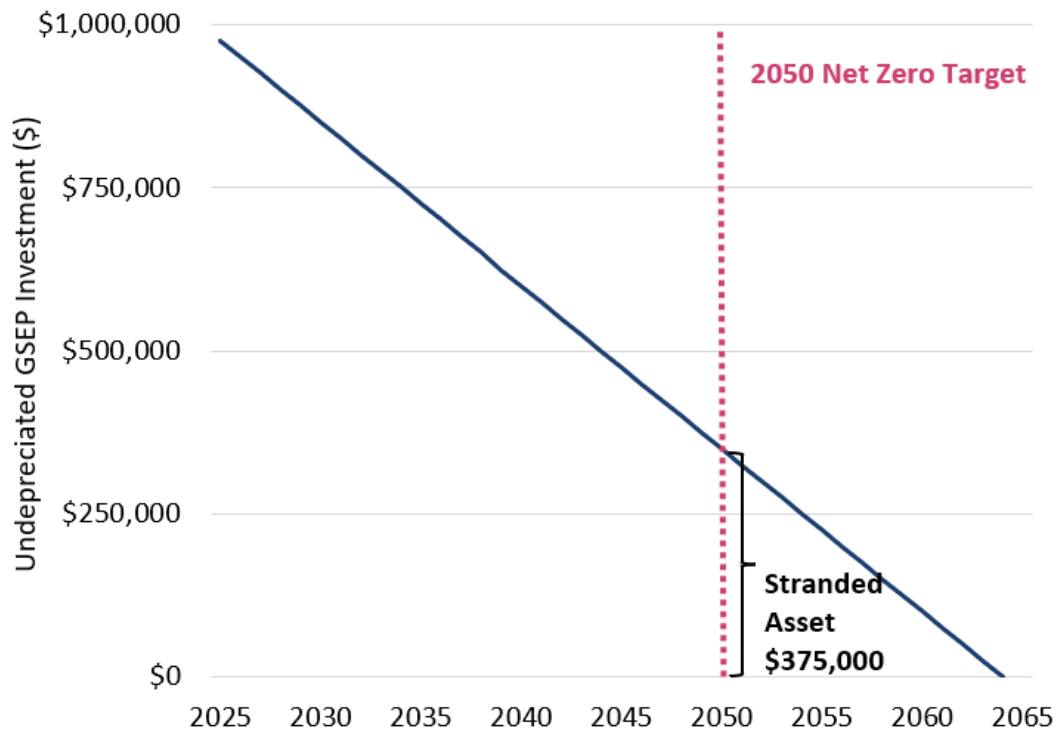
15 A GSEP-upgraded main and services would become stranded when there are no customers
16 being served by that segment of pipe and/or that pipe is no longer needed to reliably serve

⁶⁷ *National Grid*, D.P.U. 24-GSEP-03, Exh. AG-1-10, at 2.

⁶⁸ *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.).

1 demand. A radial segment of pipe could become stranded once all downstream customers
2 on that segment have electrified and are no longer using gas. As another example, a
3 networked segment of pipe may become stranded when the customers served directly by
4 that pipe have fully electrified, *and* the pipe is no longer needed to reliably serve the
5 diminished overall load of the network. Gas pipes installed in 2025 would only be
6 approximately half depreciated by the time of the Commonwealth's final 2050 emissions
7 reductions targets; pipes installed later in the GSEP program will have been utilized even
8 less by then. The following simple hypothetical example, in Figure 6 below, illustrates the
9 financial implications of a GSEP asset becoming stranded:

Figure 6: Stranded Asset Example



We assume the GSEP asset has an initial value of \$1 million and an illustrative depreciation life of 40 years. The asset is installed in 2025 and depreciated on a straight-line basis until it is fully depreciated at the end of 2064 (\$25,000 per year). To illustrate how much of the asset might become stranded, we looked at the amount of undepreciated GSEP investment at the beginning of 2050, when the Commonwealth is expected to meet its net-zero emissions targets. The remaining balance is \$375,000 since, by 2050, the asset is over two-thirds through its 40-year depreciation schedule. If this particular asset becomes redundant

1 any time before 2050 (e.g., because of reduced throughput requirements resulting from
2 voluntary customer departures and/or targeted electrification), the amount stranded would
3 be correspondingly greater. Similarly, if this asset were installed later (i.e., because it is
4 part of a future GSEP capital plan), then a still larger share of the asset would become
5 stranded.

6 The 2024 revisions to the GSEP statute require the Department to consider “the costs of
7 potential stranded assets and the benefits of avoiding financial exposure to such assets.”⁶⁹
8 Unfortunately for ratepayers, the cost of the GSEP investment is recovered by the LDC
9 through the accelerated cost recovery mechanism. Even if the LDC recovers the cost of the
10 asset through the accelerated cost recovery mechanism, the asset is nonetheless still
11 stranded if it becomes unnecessary before the end of its engineering life.

12 Stranded assets are harmful to ratepayers because: (1) ratepayers pay for the asset but do
13 not receive the full benefits of their financial contribution once the asset becomes stranded;
14 and (2) as customers leave the natural gas distribution system, the costs of stranded assets
15 will fall disproportionately on the remaining gas customers. Put simply, stranded assets
16 waste ratepayer dollars. It is fundamentally unfair to expect ratepayers to pay for massive
17 system-wide improvements in natural gas infrastructure that will become prematurely

⁶⁹ St. 2024, c. 239, § 81.

1 redundant or unnecessary if the Commonwealth is to meet its GHG emissions reduction
2 mandates, while simultaneously shouldering the costs of transitioning toward
3 electrification.

4 **Q. What are the implications of GSEP and other CapEx expenditures for rate base?**

5 A. The LDCs are making sizable capital investments related to GSEP programs every year
6 (and are making comparable non-GSEP investments).⁷⁰ As shown in Figure 1 above, the
7 LDCs, in aggregate, reported almost \$1.5 billion in capital expenditures in 2023, of which
8 more than half, \$789 million, was GSEP-related. The remaining \$667 million were other
9 non-GSEP capital expenditures. These costs will have to be recovered from customers in
10 future.

11 To highlight the potential implications of GSEP and other CapEx on ratepayers, we created
12 an illustrative forecast of the LDCs' rate base through 2050, given their current capital
13 investment plans. We project GSEP spending based on current cost-per-mile (escalated
14 only at the assumed 2 percent general inflation rate) until the end of each LDC's GSEP
15 program.

16 We utilize two different scenarios for non-GSEP capital investments. Scenario 1 projects
17 out non-GSEP capital expenditures, assuming they grow at 2 percent per year general

⁷⁰ See D.P.U. 24-GSEP-01 to 06, Exh. AG-DL-DM-4.

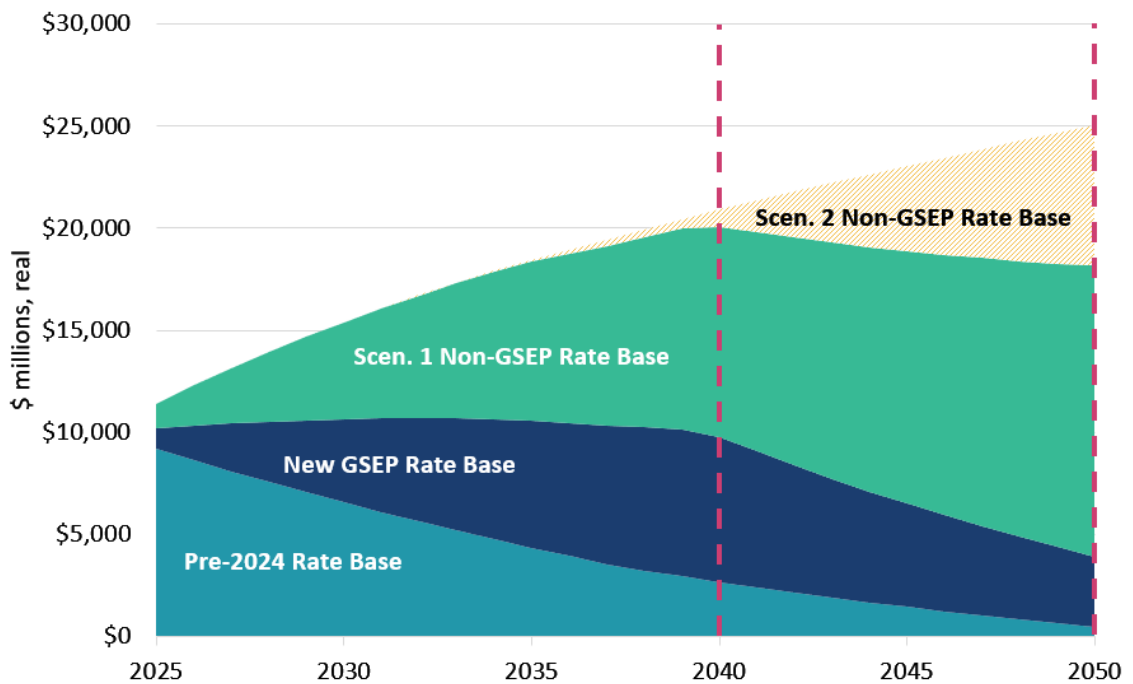
1 inflation rate through 2050. As noted above, this 2 percent inflation rate is conservative
2 relative to historic increases in pipeline capital investment costs. In this scenario, a utility's
3 total capital investments fall dramatically after the end of its GSEP program. Scenario 2 is
4 based on an alternative assumption, that once a utility completes its GSEP program, it
5 would redeploy those investment dollars to non-GSEP capital programs; effectively
6 maintaining *total* capital investments on the same 2 percent annual growth trajectory as
7 during GSEP. This reflects a scenario in which total capital funding is the limiting factor
8 for capital investments, and when GSEP stops consuming over half of the investment
9 budget, the funding is redeployed to other investment projects to keep the total on the same
10 trajectory.

11 We tracked the depreciation of the LDC's existing rate base (using net utility plant from
12 their financial statements as a proxy) over the estimated remaining useful life of these
13 assets, as well as depreciation of the new GSEP and non-GSEP investments, assuming an
14 average 40-year life for these. Each LDC's current rate base is a mix of both GSEP and
15 non-GSEP investments. These are sunk costs that cannot be avoided by changing future
16 capital expenditure patterns.

17 The results are illustrated below in Figure 7. The future total rate base is distinguished as
18 three components, with a fourth component that applies only for Scenario 2: (1) rate base
19 of existing (pre-2024 combined GSEP and non-GSEP) assets in teal at the bottom; (2) post-

1 2024 GSEP investments in dark blue in the middle; (3) post-2024 non-GSEP investments
2 in green at the top of the solid area for Scenario 1, and (4) incremental non-GSEP
3 investments for Scenario 2 shown as a shaded yellow area. Under Scenario 1, overall rate
4 base is projected to grow until about 2040 when the GSEP programs end, reaching
5 approximately \$20 billion (\$2024) in 2040 and then starting to decline due to the drop in
6 capital investments after GSEP. Under Scenario 2, the continuation of the total capital
7 investment trajectory means that rate base will continue to grow to approximately \$25
8 billion (\$2024) by 2050. Note that Figure 7 illustrates values in real (\$2024) dollars to
9 facilitate understanding the magnitudes in terms of today's dollars. If expressed in nominal
10 dollars, the values would be much higher (though the ratios would not change).

*Figure 7: Rate Base by Existing, New GSEP and New Non-GSEP CapEx
(Two Scenarios)*



This illustrates the importance of mitigating going-forward capital investments, whether they consist of GSEP projects or not. The declining, teal-colored portion of the rate base corresponding to all pre-2024 sunk investments demonstrates that, absent continued capital expenditures, the future cost of the gas system will shrink dramatically, reducing potential stranded cost exposure by approximately 95 percent by 2050. In fact, starting now to limit GSEP and non-GSEP capital spending is the most viable route to ensuring gas assets will be largely depreciated by 2050, will match their economic and useful lives, and will accommodate the anticipated declining trajectories of customer numbers and throughput.

1 **Q. How do the costs of GSEP impact ratepayers?**

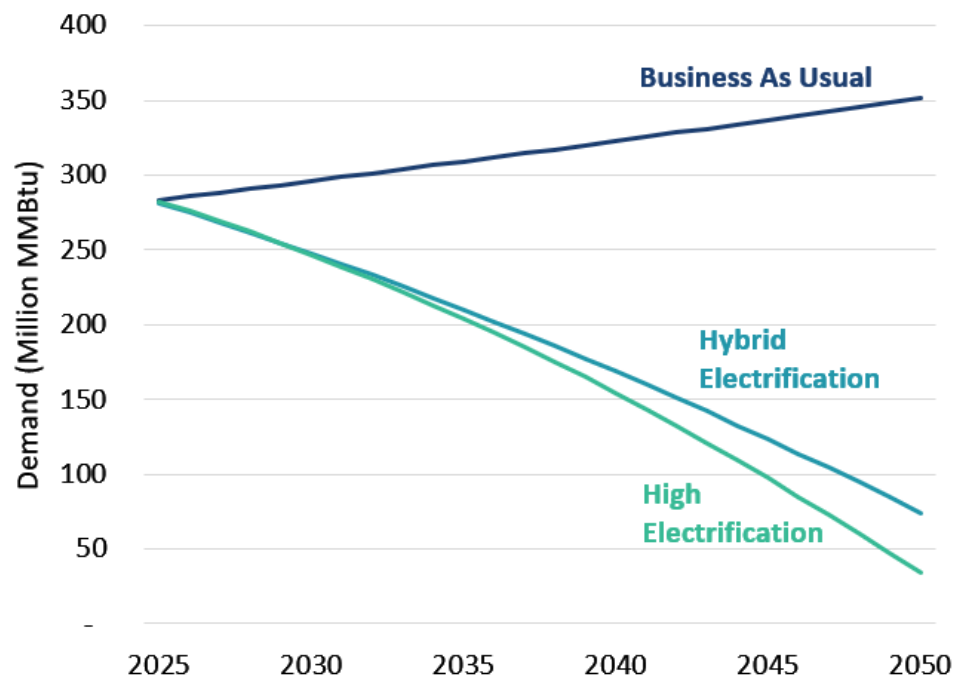
2 A. Ratepayers pay for GSEP through an accelerated cost recovery mechanism, which means
3 GSEP costs are included in ratepayer bills very quickly. Using the same analysis as just
4 discussed, we calculated a simplified statewide revenue requirement and then divide the
5 revenue requirement by the estimated volume of gas sold to estimate the average \$/MMBtu
6 bill cost. Note that this revenue requirements model accounts only for gas distribution costs
7 expressed as a function of delivered gas—the cost of the gas supply itself is not captured.

8 To estimate the revenue requirement, we use the rate base estimated above with each LDC's
9 most recent approved rate of return, grossing up for combined federal and Massachusetts
10 corporate taxes, and O&M expense (estimated as a percentage of net utility plant, based on
11 the company's 2023 Financial Statements).

12 For this analysis, we consider three gas load scenarios, all derived from the gas modeling
13 done by the LDCs' modeling consultant (E3) in D.P.U. 20-80. The first scenario is a
14 business-as-usual case based on the company's reported gas usage in their 2023 Annual
15 Returns, grown at the rate provided in E3's model input spreadsheet (BAU: 0.3 percent to
16 1.6 percent, compounded annual growth rates). The second scenario is extrapolated from
17 E3's Hybrid Electrification Scenario, which continues some reliance on gas and was
18 favored by the utilities. The third scenario is extrapolated from E3's High Electrification

Scenario, which was favorably reviewed by the Department in Order 20-80-B. These three demand scenarios are illustrated in Figure 8 below:

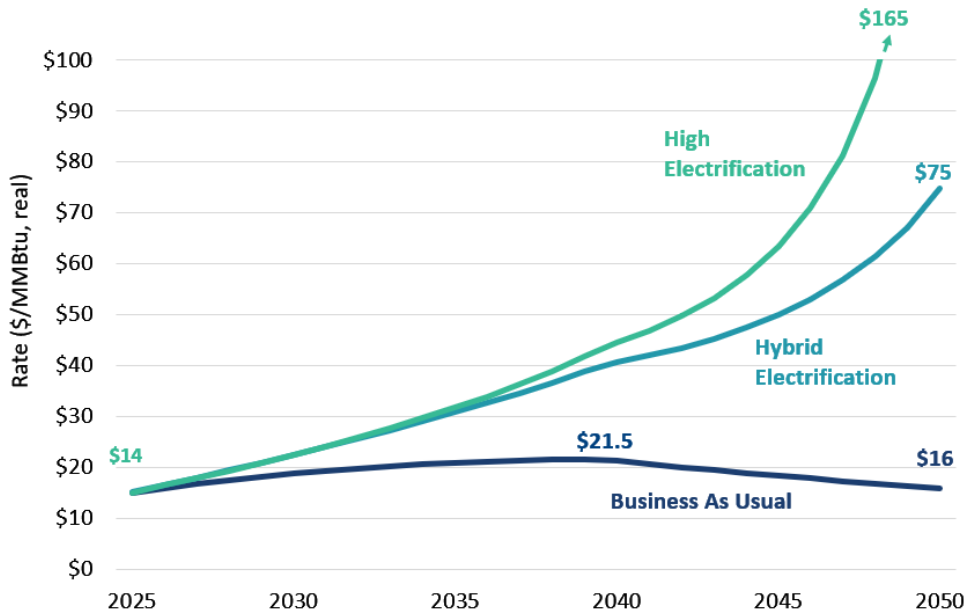
Figure 8: Gas Demand Scenarios



As shown in Figure 9 below, in the business-as-usual case, statewide customer gas delivery bills increase from about \$14/MMBtu in 2024 to \$21/MMBtu by 2040, a 50 percent increase in real terms (2024\$), then decline to \$16/MMBtu (2024\$) by 2050 due to the reduction in new investments after the end of GSEP. Notably, customer bills are projected to grow significantly year-over-year through the remainder of the GSEP program (averaging a real growth rate of about 3 percent through 2040).

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Figure 9: Bill Impact Scenarios



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In the second scenario, based on E3’s hybrid electrification demand profile (teal line), gas delivery rates and bills increase much more dramatically, and continue to increase as customers depart the gas system and throughput falls, even as revenue requirements begin to fall after the end of GSEP. In this hybrid scenario (favored by the LDCs in D.P.U. 20-80), customer delivery bills increase from \$14/MMBtu in 2024 to \$75/MMBtu by 2050 (2024\$), with annual increases averaging about 7 percent real over that period.

Using the high electrification demand profile (green line), customer bills grow at an extraordinary rate, exceeding \$165/MMBtu by 2050 (2024\$), increasing at around 7 percent real annually until 2044, then spiraling upward much faster after that, as remaining

1 load dwindles (growing at an average of 10 percent real per year through 2050).

2 This illustrative GSEP bill comparison shows that the 2025 BAU GSEP planning approach
3 only works to keep rates remotely affordable (though still considerably higher than
4 inflation) if current BAU throughput and sales growth continues through to 2050. But as
5 observed above, those BAU sales and throughput cannot come close to meeting the
6 necessary building sector emission reductions, and thus are not consistent with 21N. In the
7 hybrid electrification scenario favored by the LDCs in D.P.U. 20-80, customers nonetheless
8 see year-on-year rate increases averaging about 7 percent in real 2024\$, far above inflation,
9 and reaching distribution rates of \$75/MMBtu (in real 2024\$) by 2050. The high
10 electrification scenario, with its greater level of customer departure and throughput
11 reduction, shows still higher rates, spiraling upward for the unfortunate few ratepayers who
12 remain on the gas system. Both the LDC-favored hybrid scenario and the high
13 electrification scenario leave ratepayers with large to astronomical rate increases in gas
14 delivery charges, if capital investment, including but not limited to GSEP, continues
15 according to a BAU plan. The story is much worse, of course, in Scenario 2, where non-
16 GSEP CapEx fills in for GSEP CapEx after the end of the GSEP programs, and overall
17 distribution costs continue to rise.

1 **Q. Should the GSEP program continue to focus on system-wide pipe replacement and**
2 **upgrades?**

3 A. No. The Legislature has indicated that GSEP should no longer focus exclusively on pipe
4 replacement.⁷¹ It is no longer appropriate under the GSEP Statute (2024) to replace all
5 GSEP-eligible pipe with upgraded pipe. Replacement with upgraded pipes and equipment
6 is a wide-scale system improvement and replacement process, not a leak-reduction and
7 safety program managed prudently to control ratepayer costs. Replacing leaking and high-
8 risk pipe will still be necessary where active or imminent leaks pose a threat to public health
9 and safety. For pipe that is not leaking, the LDCs should proactively pursue a long-term
10 strategy of decommissioning (e.g., via targeted electrification or a managed transition)
11 and/or an NPA strategy. We discuss this in greater detail in Section VI.

12 It is important that LDCs shift away from the BAU strategy of replacing all potentially
13 leak-prone pipe, instead opting to decommission gas pipe and facilitate NPA installations.
14 We view this type of planning and GSEP implementation as necessary to contain the
15 otherwise exorbitant costs of GSEP and other gas system plant investments.

71 See St. 2024, c. 239, § 81 (replacing “eligible infrastructure replacement” with “eligible infrastructure measure”).

1 **V. THE DEPARTMENT SHOULD GRADUALLY REDUCE THE GSEP CAP TO 1.5**
2 **PERCENT.**

3 **Q. How does the GSEP cap work?**

4 A. Under the GSEP statute, LDCs are entitled to accelerated cost recovery for eligible
5 infrastructure replacements, subject to a cap:

6 Annual changes in the revenue requirement eligible for recovery pursuant
7 to the plan shall not exceed (i) 1.5 percent of the gas company's most recent
8 calendar year total firm revenues, including gas revenues attributable to
9 sales and transportation customers, or (ii) an amount determined by the
10 Department that is greater than 1.5 percent of the gas company's most recent
11 calendar year total firm revenues, including gas revenues attributable to
12 sales and transportation customers.⁷²

13 The GSEP revenue requirement includes depreciation expense, property taxes, and a return
14 on investments associated with the plan.⁷³ Any revenue requirement approved by the
15 Department in excess of the cap may be deferred for recovery in the following year with
16 the LDCs earning carrying costs monthly.⁷⁴

17 **Q. Why was the GSEP cap raised in 2019?**

18 A. In 2019, the Department raised the GSEP cap from the statutory minimum of 1.5 percent
19 to 3.0 percent. The Department raised the cap to mitigate, if not eliminate, ongoing

⁷² G.L. c. 164, § 145(f).

⁷³ G.L. c. 164, § 145(e).

⁷⁴ G.L. c. 164, § 145(f).

1 deferrals, as the LDCs' GSEP expenditures consistently exceeded 1.5 percent of annual
2 total firm revenues.⁷⁵ Raising the cap did not, however, eliminate deferrals. The LDCs
3 continue to seek waivers of the 3.0 percent cap⁷⁶ or deferrals of amounts that exceed the
4 3.0 percent cap.⁷⁷

5 **Q. How have circumstances changed since the Department increased the cap to 3.0**
6 **percent?**

7 A. As discussed in Section III, since 2019, the Commonwealth has taken clear and decisive
8 steps to reduce GHG emissions limits and sublimits and has amended GSEP to require
9 compliance with Chapter 21N. There is no debate that the GHG emissions limits and
10 sublimits necessitate a substantial reduction in natural gas throughput and end-use and will
11 reduce gas sales and numbers of gas customers. Consistent with the changes of law
12 governing GSEP plans, the Department's decision in the D.P.U. 20-80-B Order enunciates

⁷⁵ *Unitil*, D.P.U. 18-GSEP-01, Order, at 26 (the Department was "persuaded that accruing large deferrals would not benefit the Company or its ratepayers and would result in an outcome that is inconsistent with the intent of G.L. c. 164, § 145.").

⁷⁶ *See, e.g., NSTAR Gas*, D.P.U. 24-GREC-06, Order, at 23 (In addition to the waiver request in the current proceeding, the Company has requested a waiver of the increased cap three times since the Department increased the cap to three percent, and the reasons provided here are substantially the same as the Company's in prior waiver requests. . . This demonstrates the Company's continued inability to manage its GSEP within the cap set by the Department.).

⁷⁷ *See, e.g., Unitil*, D.P.U. 24-GREC-01; *National Grid*, D.P.U. 24-GREC-03; *Liberty*, D.P.U. 24-GREC-04; and *EGMA*, D.P.U. 24-GREC-05.

1 an end to BAU gas company operations.⁷⁸ In the case of GSEP, moving beyond BAU
2 means that the LDCs may not continue to treat GSEP as a system-wide improvement
3 mechanism to invest further funds into the gas system that will be increasingly challenging
4 for ratepayers to pay back as gas throughput and customer counts fall over time.

5 Section IV above addressed how system-wide natural gas improvement is uneconomic, and
6 many GSEP investments are likely to become stranded assets. Importantly, it is
7 fundamentally unfair and wasteful to make ratepayers pay to reinforce expensive natural
8 gas infrastructure that will not be fully utilized, while also shouldering the costs of the
9 transition to electrification and a net-zero economy.

10 In summary, under governing law and Department orders, the LDCs should be spending
11 much less on GSEP relative to 2019. The LDCs should not use replace and upgrade as the
12 default actions to remediate any potentially leak-prone pipe, regardless of whether the pipe
13 is actually leaking. The LDCs should instead focus their GSEP work on assets that are
14 leaking, or imminently at risk of leaking, that pose a threat to safety and system reliability.
15 An LDC shift away from replace and upgrade and toward decommissioning and long-term,
16 decarbonized energy alternatives will involve a commensurate reduction in the cost of the
17 GSEP program.

⁷⁸ *Future of Gas*, D.P.U. 20-80-B, Order, at 18.

Q. Should the Department lower the GSEP cap?

A. Yes. The GSEP cap is the statutorily built-in accountability to prevent LDCs from overspending through a cost recovery mechanism that otherwise lacks the prudence review of a rate case. Given the changes described above, the LDCs should be making less capital investment in pipe replacement. Lowering the cap will require the LDCs to exercise greater discretion—to only conduct GSEP work to remediate imminent threats to public safety and reliability while implementing IEP, decommissioning, NPA analyses and customer outreach.

We recommend that the Department gradually lower the cap to the statutory minimum of 1.5 percent. This recommendation is consistent with the AGO’s comments in the GSEP working group report.⁷⁹

Date	Accelerated cost recovery cap: Percent of LDC’s most recent calendar year total firm revenues
October 1, 2025	2.5 percent
October 1, 2026	2.0 percent
October 1, 2027	1.5 percent

Lowering the cap gradually is advantageous because it helps the LDCs account for costs that have been deferred and provides reasonable time for the companies to adjust their

⁷⁹ GSEP Working Group Report and Recommendations, at 44–47.

1 GSEP programs to better align with the Commonwealth’s climate mandates; particularly
2 with planning for long-term decommissioning, customer outreach, and alternative energy
3 infrastructure. If system reliability and safety expenses are necessary beyond the reduced
4 cap, the LDCs can propose cost recovery for these investments in rate cases subject to the
5 Department’s prudence review. The Department’s ability to undertake full prudence
6 examination of planning, implementation, and expenditures in a rate case makes rate case
7 proceedings superior for implementation of 21N and Order 20-80-B compliance.

8 **Q. Will lowering the GSEP cap jeopardize compliance with the Distribution Integrity**
9 **Management Plan (“DIMP”)?**

10 A. No. Compliance with the DIMP is not contingent upon GSEP funding. As discussed
11 previously, the LDCs are legally obligated to address gas leaks regardless of GSEP’s status.
12 The LDCs are required to develop and maintain a written DIMP with the following
13 elements: (a) knowledge of threats; (b) identification of threats; (c) evaluation and ranking
14 of risk; (d) identification and implementation of measures to address risks; and (e) means
15 to measure performance, monitor results, and evaluate effectiveness.⁸⁰ GSEP is a tool
16 accessible to the LDCs to fulfill the obligations of the DIMP; it simply provides a financial
17 mechanism through accelerated cost recovery to address leak-prone pipe on an expedited
18 timeline. Our testimony demonstrates how the LDCs are using GSEP to conduct system-

⁸⁰ 49 C.F.R. §§ 192.1001 through 192.1015.

1 wide improvements and thereby rebuilding much of the gas system over time. Gradually
2 lowering the GSEP cap to the statutory minimum would reduce overspending and help to
3 ensure that the LDCs focus on the greatest threats to safety and system reliability. If any
4 LDC determines that spending higher than the 1.5 percent cap is necessary, those costs
5 should be recovered through the traditional base distribution rate case process.

6 **VI. GSEP SHOULD BE USED FOR LONG-TERM IEP PLANNING**

7 **Q. What is integrated energy planning (“IEP”)?**

8 A. Long-term IEP is a process that considers overall building energy requirements and
9 decarbonized options for meeting them. To achieve the Commonwealth’s GHG mandates,
10 specifically the LDCs’ Scope 3 emissions limits in the building sector, a major reform of
11 the capital planning process is necessary. The LDCs’ existing gas planning processes,
12 including GSEP, are pipe-centric, designed to re-build, upgrade, and expand the gas system
13 gradually over time as gas system components need to be replaced. It is premised on the
14 indefinite existence of and reliance on the gas system. A planning process that is organized
15 around the gas system components that need replacement to continue operating the gas
16 system will perform poorly at achieving the broad energy transformation needed to meet
17 the Commonwealth’s GHG mandates and will be unnecessarily costly.

18 The required NPA analysis that has already begun pursuant to Order 20-80-B, although
19 important, is not sufficient to ensure the Commonwealth transitions away from natural gas

1 in favor of decarbonized heating solutions. This is because NPA analysis is still organized
2 around particular gas assets; it defines the scope, geography, and timing of the potential
3 NPAs that will be considered to match the scope, geography, and timing of a gas pipe
4 replacement project. It does not consider other leak-prone pipe outside the immediately
5 defined project. Likewise, the LDCs' narrow NPA process does not consider alternative
6 configurations of electrified or decarbonized heating technologies, with a different scope
7 or footprint, which is needed to meet goals for emissions reductions, ratepayer cost and
8 equity, and achieve the scale required by Chapter 21N.

9 IEP should not be organized around the needs of the gas system or pipe projects because,
10 in the long run, the Commonwealth's reliance on the gas system for building energy needs
11 will diminish substantially. Instead, the IEP process should be centered around a vision of
12 electrification as the primary pathway for the buildings sector to achieve GHG goals, and
13 the electrified energy system that will evolve through 2050.⁸¹ An IEP process (and a clear
14 mechanism to implement the plan) is almost certainly necessary for the energy transition
15 to achieve the scale and pace necessary to meet the Commonwealth's GHG mandates, and
16 it can also reduce the burdens (both financial and logistic) on customers.

17 **Q. What might IEP involving GSEP inventory look like?**

⁸¹ *Future of Gas*, D.P.U. 20-80-B, Order, at 35 (stating that the Commonwealth's dominant building decarbonization strategy is electrification).

1 A. The IEP process would identify and implement electrified and decarbonized alternative
2 building energy projects, working at the system level (not the pipe project level), at
3 sufficient scale and pace to achieve the Commonwealth's GHG mandates (including
4 interim targets) for the building sector and gas sector. To be sure, immediate and long-term
5 leak prone gas pipe replacement needs should influence the geography and timing of these
6 alternative building energy projects. The process would identify proposed gas capital
7 investment projects and their timing (e.g., GSEP and other replacement and upgrade
8 projects) and would prioritize customer outreach and assistance in converting the relevant
9 customers to enable decommissioning those assets before their replacement becomes
10 necessary. A prudent planning process for IEP is not pipe-centric but it would be LDC-
11 centric. Each LDC would be responsible for prudently planning capital upgrades,
12 decommissioning of selected pipes and services to avoid unnecessary pipe investments,
13 and large-scale planning to facilitate zero emissions building sector investments

14 Additional strategies might be utilized to facilitate avoiding LDC capital expenditures on
15 costly replacement pipes (e.g., delay when safe, repair rather than replace when less costly,
16 enhanced monitoring, and efficiency projects to limit demand). Such lower-cost strategies
17 may provide additional time, where needed, until the gas assets can be displaced by non-
18 gas solutions. A key feature of this approach is that wherever possible, it would avoid gas
19 capital investments by converting relevant gas customers before the gas project becomes

1 necessary. It would consider customers directly connected to the gas pipe of interest, have
2 extensive customer outreach and information, and possibly also reach downstream demand
3 that relies in part on the subject pipe to support pressures.

4 The IEP process could also incorporate non-gas (oil, propane) customers, to make
5 additional progress toward Massachusetts' GHG mandates and to make a project more
6 effective and cost-efficient (e.g., a networked geothermal project that also includes adjacent
7 oil and propane customers may have better economics). If non-gas customers are included,
8 that would potentially and likely impact the cost-benefit calculations for payoff of LDC
9 investments in alternative infrastructure measures.

10 Of course, it will be necessary for LDCs and the Department to coordinate the
11 electrification of fuel demands with the electricity planning process to ensure the grid can
12 accommodate the increased load. Broadly speaking, the current electric system has
13 considerable slack in winter, when most of the heating-dominated fuel demand occurs (the
14 electric system is sized to accommodate the higher summer peak). Estimates suggest that
15 in New England, electrifying fuel demand at a pace that is sufficient to achieve ambitious
16 climate goals may begin to encounter electric system constraints around 2035 as winter

1 peak catches up with summer peak.⁸² Localized constraints may be reached earlier, so
2 careful coordination with electric system planning, at the generation, transmission, and
3 distribution levels, is essential. That said, the EDCs are already planning to upgrade
4 substations over the upcoming decade to accommodate higher projected electricity load
5 (due to the electrification of transportation and buildings).⁸³

6 **Q. What are the advantages of IEP?**

7 A. As shown above, future gas capital investments involve very substantial funds, and
8 avoiding these investments wherever possible would not only make the energy transition
9 considerably less costly but also prevent substantial gas assets from becoming uneconomic
10 or unnecessary in future. In this way, a successful IEP process may be able to pre-empt,
11 through system-wide energy planning, a substantial share of future gas pipe projects and
12 investments, both GSEP and non-GSEP. IEP may ultimately make much of the gas
13 planning process (GSEP and non-GSEP, line extensions, and NPAs for these) redundant.

⁸² Murphy, Dean; Hagerty, J. Michael; Kavlak, Goksin; Rauschkolb, Noah; Kwork, Gabe; Jones, Ryan, *Maine Pathways to 2040: Analysis and Insights*, THE BRATTLE GROUP; EVOLVED ENERGY RESEARCH, (Jan. 2025), at 27–28:

<https://www.maine.gov/energy/sites/maine.gov.energy/files/2025-01/Maine%20Pathways%20to%202040%20Analysis%20and%20Insights.pdf>.

⁸³ *NSTAR Electric Company d/b/a Eversource Energy*, D.P.U. 22-22, Exh. ES-CAH/DPH-1, at 80–82 (NSTAR Electric plans \$956 million in capital additions to substations or distribution feeders over 10 years); *NSTAR*, D.P.U. 24-10 / *National Grid*, D.P.U. 24-11 / *Unitil*, D.P.U. 24-12, Order, at 267–270 (joint Order addressing proposed substation and CIP investments).

1 By addressing the need to replace gas infrastructure with alternative electrified and
2 decarbonized heating solutions, before the gas capital investments become necessary, the
3 IEP process can stay ahead of gas pipe replacement needs and avoid very substantial gas
4 infrastructure costs. There would still be an important role for the NPA process at the (gas)
5 project level, particularly in the near term, to help avoid nearer-term gas investments as an
6 IEP process is being developed, and also as a backstop or check on gas pipe projects that
7 might not immediately be pre-empted by the IEP process. In addition to the required NPA
8 analysis, the LDCs need to conduct some version of a comprehensive, proactive IEP
9 process with GSEP as a part of it. In the long-term, IEP is a prudent and cost-effective
10 means of addressing leak-prone pipe by transitioning customers to electric heating and
11 other decarbonized energy sources consistent with both the GSEP and Chapter 21N
12 mandates.

13 **Q. Does this conclude your testimony?**

14 **A.** Yes.