THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL
ONE ASHBURTON PLACE
BOSTON, MASSACHUSETTS 02108

ANDREA JOY CAMPBELL
ATTORNEY GENERAL

(617) 727-2200
www.mass.gov/ago

January 7, 2026

Massachusetts Department of Environmental Protection
100 Cambridge Street, Suite 900
Boston, MA 02114

Re: ***Comments on 310 CMR 7.73 Program Review Proposal***

Dear Commissioner Heiple,

The Office of the Attorney General ("AGO") respectfully submits the attached comments regarding the Massachusetts Department of Environmental Protection's program review of 310 CMR 7.73 *Reducing Methane Emissions from Natural Gas Distribution Mains and Services*.

The attached comments were prepared by Michael J. Walsh, Ph.D., who has provided expert testimony on behalf of the AGO in the ongoing Climate Compliance Plan proceedings before the Department of Public Utilities (D.P.U. 25-40 through D.P.U. 25-44/45). That testimony, also attached, addresses many of the same issues raised in the 310 CMR 7.73 program review and provides additional technical background.

The AGO has a strong interest in ensuring that the Commonwealth's climate regulations effectively reduce greenhouse gas emissions while protecting ratepayers from unnecessary costs. Ratepayers ultimately bear the costs of compliance with 310 CMR 7.73. The attached comments address how the regulation can be improved to achieve genuine emissions reductions in a cost-effective manner.

Thank you for considering these comments. Please contact me if you have any questions.

Respectfully submitted,

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

Enclosures

1. Michael J. Walsh, Ph.D comments on the 310 CMR 7.73 program review proposal and appendices;
2. Walsh direct testimony in Climate Compliance Plans, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1; and
3. Walsh appendices to direct testimony in Climate Compliance Plans, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. A through C.

COMMENTS ON THE 310 CMR 7.73 PROGRAM REVIEW PROPOSAL

Submitted on Behalf of the Office of the Attorney General

Prepared by Michael J. Walsh, Ph.D.

January 7, 2026

I. INTRODUCTION

I submit these comments in response to the Massachusetts Department of Environmental Protection's ("MassDEP") program review of 310 CMR 7.73 *Reducing Methane Emissions from Natural Gas Distribution Mains and Services*. I have provided expert testimony on behalf of the Office of the Attorney General ("AGO") in the pending Climate Compliance Plan ("CCP") proceedings before the Department of Public Utilities (D.P.U. 25-40 through D.P.U. 25-44/45), where I addressed many of the same issues raised by this program review. That testimony is attached for reference.

The central concern motivating these comments is to ensure that ratepayer funds are used to achieve tangible emissions reductions. Ratepayers bear the costs of compliance with 310 CMR 7.73 through Gas System Enhancement Plans ("GSEP"), which recover infrastructure replacement costs through utility rates. Gas distribution spending in Massachusetts has grown at a compound annual rate of approximately 7.9 percent[1] since the Gas Leaks Act. This places increasing pressure on ratepayer bills. The regulation should therefore be designed to maximize emissions reductions per dollar spent—achieving genuine climate benefits rather than incentivizing capital expenditure that may not deliver proportional emissions reductions.

In summary, I offer the following observations and recommendations aimed at aligning 310 CMR 7.73 with broader efforts to manage the energy transition:

- I support MassDEP's proposal to update emissions factors and to report emissions in metric tons of methane rather than CO_2e;
- I recommend a three-year limit period (2025-2027) to allow integration with ongoing policy developments at the Department of Public Utilities;
- I urge MassDEP to consider how the regulation can evolve beyond its reliance on pipe-material-based emissions factors toward measurement-informed approaches that target the highest-emitting leaks; and
- I encourage MassDEP to require enhanced reporting and pilot programs for advanced leak detection technologies.

The remainder of my comments are organized as follows:

- Section II addresses overarching considerations associated with methane, methane leaks, and evolving state policy;
- Section III discusses the structural limitations of the current regulation;

---

[1] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B, at 5.

- Section IV responds to MassDEP's questions; and
- Section V synthesizes these observations into conclusions and recommendations.

II. OVERARCHING CONSIDERATIONS

A. Methane's Role as a Greenhouse Gas ("GHG")

Methane is a short-lived but potent GHG: per molecule, it has a greater warming effect than CO_2, but this effect fades rapidly, contributing to intense warming for a decade. This fading characteristic distinguishes methane from CO_2, which, once emitted, mostly persists in the atmosphere for centuries. The science underlying these dynamics is well established, though ongoing refinement of quantitative measures such as the Global Warming Potential ("GWP"), which compares the impacts of CO_2 and CH_4 over a defined timescale (typically 20 or 100 years), continues. These factors have been regularly updated with each successive Intergovernmental Panel on Climate Change ("IPCC") Assessment Report (Table 1).

Table 1. Global Warming Potentials for Methane from Recent IPCC Reports.

IPCC Reports	GWP-100	GWP-20
2007 Fourth Assessment Report (AR4)	25	72
2014 Fifth Assessment Report (AR5)	28	84
2021 Sixth Assessment Report (AR6)	29.8	82.4

Because of these dynamics, as temperatures rise, the relative benefit of avoiding CH_4 versus CO_2 also changes. This is best illustrated in a comparison of the social cost of methane and carbon dioxide: the social cost of methane is approximately 8.4 times that of CO_2 per ton emitted in 2020, rising to 13.5 times by 2050 (See Appendix Table 2).[2]

The GWP is a helpful but fundamentally imperfect tool to guide the prioritization of GHG reduction efforts. Given its limitations, the IPCC acknowledges that there may be policy-appropriate reasons to use alternative comparison metrics (e.g., social cost in lieu of GWP) and even separate gases into multiple baskets for policy purposes without attempting to compare emissions factors.[3] Further, statewide inventories suggest that fugitive gas system emissions are a small proportion of both statewide total emissions (1.1 percent) and combustion emissions

---

[2] *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, U.S. ENVIRONMENTAL PROTECTION AGENCY (Nov. 2023), available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

[3] Piers Foster, et al., *The Earth's Energy Budget, Climate Feedbacks and Climate Sensitivity; Physical Considerations in Emission Metric Choice*, at 1017 (2021), https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-7/ ("This report does not recommend an emissions metric because the appropriateness of the choice depends on the purposes for which gases or forcing agents are being compared. Emissions metrics can facilitate the comparison of effects of emissions in support of policy goals. They do not define policy goals or targets but can support the evaluation and implementation of choices within multi-component policies (e.g., they can help prioritize which emissions to abate). The choice of metric will depend on which aspects of climate change are most important to a particular application or stakeholder and over which time horizons. Different international and national climate policy goals may lead to different conclusions about what is the most suitable emissions metric.").

from gas use (4.4 percent).[4] For policies that solely seek to reduce methane emissions, such as 310 CMR 7.73, it is justifiably more administratively efficient and informative to use methane units rather than conversion factors subject to regular revision and changing weighting.

B. Leak Emissions Factors are Inherently Uncertain and May Mischaracterize Actual Emissions

Emissions accounting associated with gas consumption is based on metered transfers of volumetric units of methane and high-fidelity combustion-related emission factors based on those units and reported volumetric energy contents. These measurement methods achieve a relatively high degree of accuracy, ensuring that greenhouse gas inventories derived from them accurately represent emissions.

In contrast, quantifying methane emissions from leaky pipes is subject to varying uncertainties. Leaked methane emissions are stochastic in that, while a probability distribution can describe the range of leak intensity, the amount of methane evolved from a leak is determined by several factors. Some of these factors (pipe material, age, surrounding soil conditions, operating pressure) can vary across both sub-annual (seasonal system operation changes, ground temperature-induced shifts) and annual time scales (degradation). Across a system, the number of leaks can vary, the structure of a single leak can vary, and hydraulic conditions can vary over operational time scales. All these factors influence the amount of gas escaping from the system.

"Super-emitters" make it challenging to base emissions estimates solely on equipment inventories (pipe miles, service counts). A 2016 study of methane leaks in Boston showed wide variation in leak sizes: the top 20 percent of leaks caused 75 percent of emissions, the top 6 percent accounted for 50 percent, and one leak alone was responsible for 25 percent.[5] This finding is consistent with other distribution system studies. Methane emissions follow extreme (fat-tailed) distributions. Under such a distribution, the bulk of methane emissions is being driven by "abnormal" leaks.

Bottom-up measurements, whether conducted with field equipment or advanced mobile leak-detection technology, capture a snapshot of the leak and under-sample the abnormal conditions. Bottom-up street-level measurements can also miss leaks that arise from building gas equipment. This largely explains why top-down emission surveys that integrate over larger geographies and time periods observe higher emissions than bottom-up inventories estimate (even when those bottom-up inventories include building equipment).

For example, a 2021 study by Sargent et al. found that total methane emissions in the Boston area were higher than those estimated by the Commonwealth's inventories and showed

---

[4] *CCPs*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B, at 30 (Table 10).

[5] Margaret F. Hendrick, et al., *Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments*, ENVIRONMENTAL POLLUTION (Jun. 2016), https://doi.org/10.1016/j.envpol.2016.01.094.

no observable reduction in methane during the first six years of GSEPs studied.[6] Top-down inventories capture important variability, but due to the coarse scale of analysis, they struggle to attribute it in an actionable way for equipment-level interventions.

C. Future Emissions from a Predominantly Plastic System Are Unknown but Will Require a New Regulatory Structure

Plastic pipes and system modernization can reduce leak-based emissions. However, such systems are not immune to leaks or degradation over time. Weller et al. observed a modest increase in leak rates in plastic pipe with increasing age,[7] though this sample only included plastic pipes under 50 years of age. Leaks of environmental and safety concern will persist even in modernized systems. While it is likely that there will be fewer leaks and lower overall emissions, methane mitigation will become increasingly important as temperatures rise. Once the system is predominantly plastic, the current pipe-material-based regulatory framework will provide no mechanism to drive further emissions reductions. The current pipe-based inventory approach will be ineffective in mitigating these emissions.

D. The Commonwealth is Developing a "Managed Transition" Strategy

The policy developments since 2020 demonstrate increasing efforts by the legislative, executive, and regulatory branches of the Massachusetts government to create alternatives to gas system investment, with the understanding that the gas system will be underutilized as the Commonwealth advances its climate efforts. A summary of these activities is provided in Appendix II. Collectively, these developments signal that the Commonwealth views the gas distribution system as transitioning toward a smaller footprint.

A central nascent component of this managed transition effort is the targeted electrification of customers best served by leak-prone pipe through integrated energy planning ("IEP") to identify non-pipeline alternatives ("NPAs"). These strategies are intended to mitigate the expense and necessity of replacing pipes susceptible to leakage by facilitating customers' transition away from gas service and subsequently discontinuing service. These ongoing policy developments support a shorter limit period for 310 CMR 7.73, allowing MassDEP to incorporate the outcomes of CCP proceedings and early NPA and targeted electrification efforts into subsequent regulatory updates.

III. STRUCTURAL LIMITATIONS OF THE CURRENT REGULATION

The current regulation operates as an indirect regulation of pipe material rather than a direct regulation of methane emissions. Emissions limits are calculated based on miles of pipe and the number of services by material type, applying standard emissions factors to these

---

6 M.R. Sargent, et al., *Majority of US urban natural gas emissions unaccounted for in inventories*, PROC. NATL. ACAD. SCI. U.S.A., at 44 (2021), https://doi.org/10.1073/pnas.2105804118.

7 Weller, Zachary D., et. al, *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems*, ENVIRONMENTAL SCIENCE & TECHNOLOGY (Jun. 10, 2020), at 8958–8967. https://doi.org/10.1021/acs.est.0c00437.

infrastructure counts. Compliance is achieved by replacing higher-emissions-factor pipe (cast iron, unprotected steel) with lower-emissions-factor pipe (plastic).

This design biases investment toward replacement over alternatives. Because the metric is based solely on pipe material, it does not recognize emissions reductions achieved through direct leak repair, relining, or other non-replacement strategies. A Massachusetts natural gas local distribution company ("LDC") that repairs a large leak on a cast iron main receives no credit under 310 CMR 7.73, while an LDC that replaces a non-leaking cast iron main receives full credit for the change in pipe material. The regulation does not distinguish between actively leaking infrastructure and pipe that may never develop significant leaks during its remaining service life.

The current approach overlooks emissions reductions associated with lower-cost strategies for methane management. The standard emissions factors do not adequately account for the impact of interventions other than pipe replacement. These include conventional leak patching methods and advanced approaches such as relining or CISBOT sealing,[8] all of which can substantially reduce methane emissions while preserving the material classification of the pipes. Although these measures effectively lower methane emissions, the Commonwealth's inventory and 310 CMR 7.73 currently do not reflect the mitigating impact of these actions due to the inherent limitation of the pipe-based inventory approach.

My analysis in the CCP proceedings quantified the cost-effectiveness challenge. The 20-year cumulative social cost of methane leaked from a typical mile of cast iron pipe is approximately $156,000, based on EPA's social cost of methane and the 310 CMR 7.73 emissions factor for cast iron.[9] The cost to replace that mile of pipe ranges from $2 million to $10 million, depending on the LDC and the location. Viewed from an emissions mitigation lens, pipe replacement delivers very little benefit for its cost.

This concern is amplified by the risk of stranded costs. If gas consumption declines significantly as the Commonwealth pursues its building sector emissions sublimits, pipe replaced today may serve a diminishing customer base—concentrating costs on remaining ratepayers or rendering the investment obsolete. Pipe replacement investments made in areas that will eventually be targeted for electrification and system decommissioning may deliver limited long-term value. The Department has recognized this concern—its April 2025 GSEP Reform Orders require LDCs to demonstrate evaluation of advanced leak repair technology as an alternative to pipe replacement.[10] Alignment between 310 CMR 7.73 and this regulatory direction would support more cost-effective methane mitigation.

The high potency of methane as a GHG, the short atmospheric lifetime of methane, and the fat-tailed distribution of methane emissions all suggest that cost-effective efforts to mitigate methane emissions should be targeted at the largest emitters, rather than based on broad replacement of leak-prone infrastructure. The evidence reviewed here demonstrates that the current activity-based approach may mischaracterize both the magnitude and distribution of

---

[8] CISBOT is a robotic system that enters live, large diameter cast iron gas main to internally remediate leaks and prevent new leaks from forming by injecting a sealant into the joint material.

[9] *CCP*, D.P.U. 25-40 through D.P.U. 25-44/45, Exh. AG-MJW-1, App. B, at 34.

[10] *GSEP*, D.P.U. 24-GSEP-01 through 24-GSEP-06, <u>Orders</u> (Apr. 30, 2025).

methane emissions, with implications for cost-recovery mechanisms, environmental compliance, and climate policy effectiveness.

IV. RESPONSES TO MASSDEP'S QUESTIONS

A. Should the declining annual emissions limits be extended beyond 2024? If so, should limits be extended through 2027 or 2029?

I recommend a three-year limit period ending in 2027—consistent with MassDEP's Option B. As discussed above, the regulatory landscape governing gas distribution infrastructure is undergoing significant change. A three-year limit period would position MassDEP to incorporate:

- The outcomes of the CCP proceedings, currently pending before Department, are expected to be decided in 2026;
- Early results from NPA evaluations and targeted electrification pilots, including National Grid's Winthrop and Leominster pilots filed under D.P.U. 24-194; and
- Any modifications to GSEP practices resulting from the April 2025 GSEP Reform Orders, including the new requirement that LDCs evaluate advanced leak repair technology as an alternative to pipe replacement.

A shorter limit period also mitigates the set-aside accumulation concern that MassDEP identified: over five years, shortfalls in pipeline replacement that cannot be made up in subsequent years would compound, potentially straining the set-aside mechanism. A three-year horizon reduces this risk.

If LDCs increasingly pursue non-pipe replacement strategies—whether through advanced leak repair, retirement without replacement, or targeted electrification—the regulatory framework may need to evolve to recognize these approaches. A three-year period allows MassDEP to reassess the regulation in light of these evolving practices before setting limits for 2028 and beyond.

B. What is the Appropriate Size of the Emissions Set-Aside?

The historical utilization data suggest that a 5 percent set-aside has been adequate through 2024, though utilization has trended upward—from 7.0 percent in 2021 to 21.3 percent in 2024. For a three-year limit period, a 5 percent set-aside is likely sufficient.

If LDCs increasingly pursue repair rather than replacement, they may require set-aside allocations because the higher-emissions-factor pipe remains in their inventory—even if actual emissions have been reduced through leak remediation.

This illustrates a structural limitation of the current framework: an LDC that achieves genuine emissions reductions through non-pipeline mitigation receives no compliance credit, while an LDC that replaces non-leaking pipe receives full credit for the change in material. The set-aside becomes a workaround for a regulation that does not recognize non-replacement mitigation. While this may be practical if the only mitigation mechanism is replacement, the potential utilization of advanced repair, or of temporary repair followed by retirement, requires an alternative mechanism. Lower-cost strategies that are aligned with the managed transition principles established by Department would steadily consume the set-aside.

I recommend that MassDEP:

- **Maintain a 5 percent set-aside for the 2025-2027 period**, which historical data suggest is adequate for a three-year horizon;
- **Require enhanced reporting on set-aside petitions**, including the specific circumstances necessitating set-aside use and whether those circumstances reflect a change in spending to comply with 2.5 percent cap, unexpected events, strategic shifts toward non-replacement approaches, or other factors; and
- **Prioritize development of credit mechanisms for non-replacement mitigation** (as discussed in Section V), which would reduce set-aside demand from LDCs pursuing cost-effective alternatives to pipe replacement while ensuring those alternatives deliver verified emissions reductions.

C. Are there practical, economically feasible technologies to detect and quantify gas leaks?

Yes, though each available technology involves tradeoffs between detection precision, quantification accuracy, geographic coverage, and cost. MassDEP's enabling statute requires this program review to evaluate whether to require the use of feasible technologies to detect and quantify gas leaks.

The core challenge is that detection and quantification are in tension. Methane gas diffuses rapidly. Detection requires geospatially precise active effort, which may come at the cost of obtaining sufficient multiple measurements to quantify a leak accurately. Currently, Advanced Mobile Leak Detection ("AMLD") methods, such as those employed by Unitil,[11] offer high spatial precision but capture only a snapshot that may not reflect average emissions over time. Accurate quantification often requires integrating measurements over longer time horizons and broader areas, which may practically limit the ability to pinpoint emissions. The 2021 study by Sargent et al. exemplifies this approach: it provides robust quantification of regional emissions but cannot attribute them to specific infrastructure.[12]

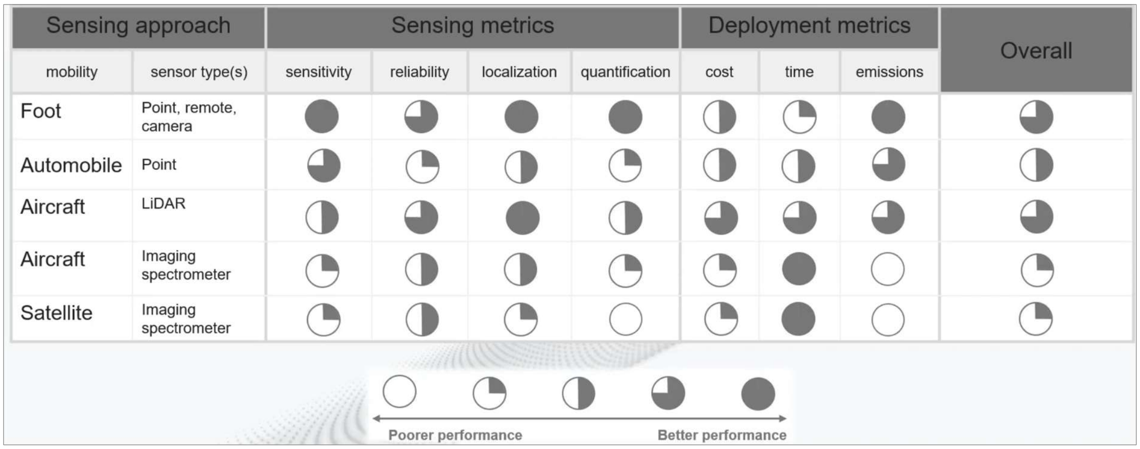
Figure 1 below shows an illustration by Bridger Photonics comparing AMLD with other measurement strategies, including aerial LiDAR measurements. Each involves tradeoffs associated with different metrics. Notably, in 2025, Pacific Gas and Electric ("PG&E") and Bridger Photonics announced an initiative to measure distribution system leaks from PG&E's system using aerial LiDAR measurements. This development suggests that aerial methods are maturing toward utility-scale deployment and warrants monitoring by MassDEP.

---

[11] *Unitil 2024 System Overview and Next Steps: Methane Emission Assessment*, NORTHEAST GAS ASSOCIATION (Apr. 4, 2024), https://northeastgas.org/files/galleries/Day_1,_Session_2_Unitil_EmissionAssessment_Demo_V2.pdf.

[12] M.R. Sargent, et. al, *Majority of US urban natural gas emissions unaccounted for in inventories*, PROC. NATL. ACAD. SCI. U.S.A., at 44 (2021).

Figure 1. Comparison of leak detection methods duplicated from a presentation by Bridger Photonics on their work in SoCalGas territory.[13] Note that this may not reflect advancements or the perspective of competitors such as those who operate AMLD efforts.



A comparison of the Unitil and Sargent studies illustrates these tradeoffs and illuminates a fundamental limitation of activity-based emissions factors that MassDEP should consider in evaluating the future of 310 CMR 7.73.

Unitil's 2023 Picarro assessment found measured emissions from its Massachusetts distribution infrastructure to be approximately three to ten times lower than GHGI and EPA emissions factor estimates, respectively—a system with 86 percent modern pipe and a zero-leak backlog performing substantially better than generic factors predict. In contrast, Sargent et al. (2021) documented Boston-area methane emissions approximately six times *higher* than bottom-up inventory estimates (inclusive of behind-the-meter) over an eight-year period, with no observable improvement despite active pipeline replacement.

These findings are not contradictory; rather, they reveal that activity-based emissions factors can be systematically wrong in *either direction* depending on utility-specific conditions that material-based classifications cannot capture. The atmospheric studies encompass all sources including beyond-the-meter emissions, customer equipment, and episodic releases, while AMLD isolates distribution infrastructure performance. Further analysis and review of methods and underlying datasets are necessary to elucidate the key drivers of the observed differences.[14]

---

[13] SoCalGas and Bridger Photonics, Inc., *Gas Mapping LiDAR™ Airborne Methane Leak Detection and Emissions Monitoring,* YouTube video (Dec. 2022), https://www.youtube.com/watch?v=sATyOnC_YzY.

[14] How such quantification methods are calibrated should be an area of further understanding to ensure that calibration approaches are accurately representative in Massachusetts application areas. *See, e.g.,* MacMullin, Sean, and François-Xavier Rongère, *Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network. Atmospheric Environment: X* 17: 100201 (2023), https://doi.org/10.1016/j.aeaoa.2023.100201.

Both AMLD and aerial LiDAR methods have the potential to improve across all metric areas. Combined with ongoing comprehensive atmospheric measurements, such methods can be useful to target leaks and assess ongoing progress at a high level.

From an economic feasibility standpoint, AMLD assessments such as Unitil's Picarro study represent a manageable investment for utilities already conducting leak surveys. Aerial LiDAR is newer, and costs may decrease as the technology matures. The EPA's recent Request for Information on methane measurement technologies, which received 63 responses, including four specifically addressing distribution systems, indicates active federal attention to these questions and may yield additional guidance.

Based on the current state of technology, I do not recommend that MassDEP mandate a specific measurement approach at this time. However, as discussed in Section V, I recommend that MassDEP require each GSEP LDC to conduct an AMLD or equivalent pilot study to establish baseline emissions data, and that MassDEP enhance reporting requirements to build the data foundation for potential future measurement-informed regulation.

V. CONCLUSION & RECOMMENDATIONS

The current regulatory framework creates a disconnect between compliance and actual emissions reduction. Accountable, trackable reductions can only be observed with high confidence through measurement, yet the regulation relies on pipe-material proxies that may mischaracterize actual emissions. Meaningful, cost-effective action on methane emissions requires moving beyond tracking based solely on pipeline materials toward approaches that target actual methane releases.

I recommend that MassDEP use this program review cycle to begin shifting the direction of methane emissions management away from pipe inventory approaches toward developing robust methods and practices for long-term management of methane leaks from utility gas systems. With respect to MassDEP's specific questions, I recommend:

- **A three-year limit period (2025-2027)**, consistent with MassDEP's Option B, to allow integration of CCP outcomes, early NPA and targeted electrification results, and GSEP Reform Order implementation into subsequent regulatory updates; and
- **A 5 percent set-aside**, which historical data suggest is adequate for a three-year horizon, with enhanced reporting on set-aside petitions to ensure the mechanism serves its intended purpose of addressing genuinely unexpected circumstances rather than becoming a routine compliance pathway.

With respect to the broader regulatory framework, I recommend that MassDEP take the following steps:

- **Measurement Technology Assessment.** MassDEP and the Department of Public Utilities should require the LDCs to conduct a Measurement Technology Assessment. This assessment would identify candidate measurement technologies appropriate to the LDC's system, which may include AMLD, aerial survey, fixed sensor networks (e.g., partnership with the academic team responsible for, or other emerging approaches), and propose a pilot study covering a representative portion of the distribution system. The assessment should include estimated costs, timeline, and how findings would be used to inform mitigation priorities. LDCs that have already conducted such assessments, such as Unitil, could submit their existing work with any proposed refinements;

- **Enhance reporting requirements.** MassDEP should expand current 310 CMR 7.73 reporting to include well-formatted, geocoded leak data, summaries of leak repairs by material type, repair method employed (e.g., replacement, patching, relining, robotic sealing), and comparisons of estimated versus measured emissions where AMLD data are available. Such information can be used by multiple parties to support long-term methane leak tracking and quantification. Much of this information is already provided in Annual Service Quality reports, however, it should be submitted using a consistent and accessible data format;
- **Develop credit mechanisms for non-replacement mitigation.** The current regulation provides compliance credit only for pipe replacement, creating a systematic bias against potentially more cost-effective alternatives. MassDEP should develop a methodology to credit verified emissions reductions from direct leak repair, pipeline relining, or robotic joint sealing (e.g., CISBOT). Such a mechanism could require documentation of the leak repaired, the repair method used, and verification that the repair was effective. This would align 310 CMR 7.73 with the Department of Public Utilities' April 2025 GSEP Reform Orders, which require LDCs to demonstrate evaluation of advanced leak repair technology as an alternative to pipe replacement; and
- **Articulate a path toward measurement-informed regulation.** While a wholesale shift to measurement-based limits may not be feasible in this program review cycle, MassDEP should articulate a vision for how the regulation can evolve toward a framework that relies on actual emissions data rather than pipe-material proxies. This could take the form of a policy statement in the regulatory preamble, a commitment to convene a technical working group, or a timeline for evaluating measurement-based approaches in the next program review cycle. The near-term steps recommended above would build the data foundation for such a transition.

310 CMR 7.73 serves an important function in establishing accountability for methane emissions from gas distribution infrastructure. However, the current framework's reliance on pipe-material-based emissions factors limits its effectiveness and may not support the most cost-effective path to achieving the Commonwealth's climate targets.

Ratepayers bear the costs of compliance with this regulation; as such they deserve a regulatory framework that delivers genuine emissions reductions—not merely changes in pipe material inventory.

Respectfully submitted,

Michael J. Walsh, Ph.D.
Managing Partner, Groundwork Data

VI. Appendix I: The Increasing Relative Cost of Methane Emissions

Table 2. *Estimates of the Social Cost of Greenhouse Gases (SC-GHG), 2020-2080 (2020 dollars)*. Adapted from Reference 2. EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (2023)

	SC-GHG and Near-term Ramsey Discount Rate with ratio of carbon dioxide and methane costs								
	$SC\text{-}CO_2$ *(2020 dollars per metric ton of CO_2)*			$SC\text{-}CH_4$ *(2020 dollars per metric ton of CH_4)*			$SC\text{-}CO_2$ / $SC\text{-}CH_4$ *(Ratio of Social Costs)*		
	Near-term rate			Near-term rate			Near-term rate		
Emission Year	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2020	120	190	340	1,300	1,600	2,300	10.8	8.4	6.8
2030	140	230	380	1,900	2,400	3,200	13.6	10.4	8.4
2040	170	270	430	2,700	3,300	4,200	15.9	12.2	9.8
2050	200	310	480	3,500	4,200	5,300	17.5	13.5	11.0
2060	230	350	530	4,300	5,100	6,300	18.7	14.6	11.9
2070	260	380	570	5,000	5,900	7,200	19.2	15.5	12.6
2080	280	410	600	5,800	6,800	8,200	20.7	16.6	13.7

Values of $SC\text{-}CO_2$ and $SC\text{-}CH_4$, are rounded to two significant figures. The annual unrounded estimates are available in Appendix A.5 and at: https://www.epa.gov/environmental-economics/scghg.

VII. Appendix II: Massachusetts Policy Developments Since 2020 Relevant to 310 CMR 7.73 Program Review

<u>**Climate Planning**</u>

Massachusetts Executive Office of Energy and Environmental Affairs: Clean Energy and Climate Plan for 2025 and 2030 (Jun. 2022) and Clean Energy and Climate Plan for 2050 (Dec. 2022)

These plans establish sector-specific sublimits requiring 80–90 percent reductions in residential gas use and 60–90 percent reductions in commercial and industrial gas use to achieve compliance. The CECP's Strategy *N1 Target Non-Energy Emissions That Can Be Abated or Replaced* (pages 77–78) describes a role for 310 CMR 7.73 in reducing emissions. Still, it emphasizes (notably in this section on non-energy emissions) the role of electrification and targeted decommissioning in informing gas system investment decisions.

<u>**DPU Regulatory Orders**</u>

D.P.U. 20-80-B Order (Dec. 6, 2023)

In D.P.U. 20-80-B, the Department announced that, going-forward, it will "discourage further expansion of the natural gas distribution system," apply "close scrutiny" to minimize costs that may be stranded, and "explore opportunities for strategic and targeted decommissioning" of portions of LDC service territories. <u>Order</u>, at 14–15. The order also required LDCs to file CCPs demonstrating how they will contribute to prescribed GHG emissions sublimits for both Scope 1 and Scope 3 emissions. *Id*. at 134. Those CCPs highlight the LDCs' efforts to replace pipes to mitigate methane emissions as well as employ new technologies for identifying leaks. The plans are currently under review by the Department (D.P.U. 25-40 through D.P.U. 25-44/45).

GSEP, D.P.U. 24-GSEP-01 through 24-GSEP-06 Orders (Apr. 30, 2025)

These GSEP reform orders implemented five significant reforms: (1) reducing the revenue cap from 3.0 percent to 2.5 percent; (2) allowing spending up to 3.0 percent for NPAs (0.5 percent on top of the 3 percent cap); (3) eliminating carrying charges on deferred GSEP expenditures; (4) requiring more rigorous risk prioritization; and (5) requiring LDCs to demonstrate evaluation of advanced leak repair technology as an alternative to pipe replacement. These reforms reflect a shift from blanket pipe replacement toward more targeted, cost-effective approaches.

<u>**Draft Utility Managed Transition Frameworks Under Development**</u>

Draft NPA Framework, LDCs-1, D.P.U. 25-40 through D.P.U. 25-44/45 (2025)

The jointly proposed NPA framework (required by D.P.U. Order 20-80-B) establishes an alternatives evaluation process for LDC investment decisions, seeking to identify opportunities to avoid conventional gas system investments. The Framework is currently under review by the DPU as part of the CCP Proceedings.

IEP Electric Sector Modernization Plans ("ESMPs") Process

Electric Distribution Companies (EDCs) have put forward proposals to implement integrated gas and electric planning as part of the legislatively mandated ESMPs. This initiative aims to identify opportunities for coordinated investment in both gas and electric infrastructure. Currently, EDCs are facilitating a stakeholder engagement process to refine the approach to

IEP, with significant emphasis placed on addressing the challenges associated with leak-prone gas infrastructure.

Targeted Electrification Pilots

Order 20-80-B requires all LDCs to file proposals for targeted electrification pilots by March 1, 2026. The first pilot was filed by National Grid in D.P.U. 24-194), in which National Grid proposal targets 14 streets for pilots in Winthrop and Leominster.

<u>State Legislation</u>

An Act Driving Clean Energy and Offshore Wind (2022) *St. 2022, c. 179, § 58.*

This act expanded GSEP-eligible activities to include "advanced leak repair technology," providing a pathway for LDCs to address leak-prone infrastructure through methods other than full pipe replacement. This legislative change recognized that alternatives to traditional replacement may be more cost-effective in certain circumstances.

An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers (2024) *St. 2024, c. 239, §§ 77, 81.*

Section 81 further amended GSEP to allow cost recovery for "retirement" without replacement and requires assessment of benefits, costs, and potential for stranded assets. Section 77 authorized the Department to "vary the uniformity of the availability of natural gas service" to "advance the public interest in reducing greenhouse gas emissions"—enabling strategic, area-based decommissioning.