Testimony of

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Before the Rhode Island Public Utilities Commission
on Behalf of the Conservation Law Foundation

Docket No. 23-49-NG

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I. EXECUTIVE SUMMARY

Michael J. Walsh is a Partner with Groundwork Data Inc. Dorie Seavey is a Senior Research Scientist with Groundwork Data Inc. They are testifying in this proceeding on behalf of the Conservation Law Foundation ("CLF") regarding The Narragansett Electric Company's (d/b/a/ Rhode Island Energy) ("Rhode Island Energy" or the "Company") Proposed FY 2025 Gas Infrastructure, Safety, and Reliability Plan ("ISR").

They testify to provide information to the Rhode Island Public Utilities Commission ("PUC") demonstrating how the proposed ISR plan is not aligned with the 2021 Act on Climate and provide guidance on how the ISR can incorporate aligned actions.

While the work proposed by the ISR results in incrementally lower accounted greenhouse gas emissions for the State, it is not a strategy that is consistent with the rapid reduction and ultimate elimination of emissions that is required under the Act on Climate.

Further, since the elimination of emissions requires a substantial reduction in utility gas consumption, the gas system will be substantially underutilized relative to today. This creates a challenge for cost recovery, especially given the continued investments made under the ISR. As more customers leave the gas system, cost recovery becomes concentrated on a smaller group that is likely to be disproportionately low-income, renters, and informationally isolated populations.

To avoid this, the PUC, the Company, and its customers will need to manage the transition more proactively. One management strategy is the decommissioning of pipeline segments that are otherwise slated for replacement investment. Customers would transition their equipment to all-electric or partially-electric with a tank fuel. While such conversions can be supported by incentives, more financial support would likely be needed. The potential impact of this strategy at scale is currently being investigated in the PUC's Future of Gas Investigation (RIPUC Docket No. 23-01-NG).

This testimony describes segment decommissioning and presents an illustrative analytical case study to demonstrate how alternative strategies can be used to align the gas system and buildings with the Act on Climate. This analysis demonstrates that an unmanaged electrification path, in which ISR projects proceed but serviced buildings steadily depart the system, incurs the highest cumulative capital costs. The gas system becomes increasingly underutilized as customers steadily electrify over the next 25 years. Alternatively, electrifying served buildings and decommissioning the associated pipeline segment results in lower capital costs while achieving emissions reductions consistent with the Act on Climate. The use of partial electrification and the conversion from utility fuel to tank fuel can also help address situations where full electrification is challenged by distribution system constraints or customer preferences.

There are likely several projects in the FY2025 ISR plan that are suitable for segment decommissioning. While completing a segment decommissioning project is impractical in the current proposed ISR plan, these sites could be deferred to future ISRs to provide sufficient time to develop a PUC evaluation framework, engage with customers, and conduct a more detailed strategy analysis.

II. INTRODUCTION AND QUALIFICATIONS

<u>Michael J. Walsh</u>

Q. Dr. Walsh, please state your name, title, and employer.

A. My name is Michael J. Walsh. I am a Founding Partner at Groundwork Data.

Q. Dr. Walsh, please describe Groundwork Data

A. Groundwork Data offers advisory, research, and technology services to accelerate a clean, equitable, and resilient energy transition. Groundwork Data helps its clients and partners understand the future of gas and the future of heat and works with them to develop the frameworks and tools necessary to manage the thermal energy transition with a hyper-local focus. Founded in 2022, Groundwork has projects focused on the energy transition in six states, along with several municipally-focused projects. Groundwork Data currently exclusively serves non-profit and public sector (including state, federal, and municipal) clients to help our clients and partners overcome foundational information asymmetries in the energy transition.

Q. Dr. Walsh, please summarize your professional and educational experience.

A. In 2021, I launched a practice focused on supporting public sector clients in managing the transition off of gas. In 2022, I co-founded Groundwork Data, where this practice is now held. During this time, I have supported a diverse set of clients on gas and energy transition projects. My areas of expertise include building electrification, renewable fuels, waste energy recovery, utility management, and decarbonization planning at municipal, state, and global scales.

Before this work, I was a senior associate at the Cadmus Group, an energy and sustainability consultancy headquartered in Massachusetts. At Cadmus, I was the Project Director for the Massachusetts Decarbonization Roadmap Study and the Rhode Island Carbon Pricing Study. I also led and assisted on several municipally-focused decarbonization planning projects, several energy efficiency program assessments, and private sector environmental social governance projects.

From 2017 to 2019, I held a senior research scientist position at the Boston University Institute for Sustainable Energy and a Research Assistant Professorship at the Boston University Department of Earth and Environment. In these roles, I served as the technical lead of the Carbon Free Boston Report, a city-wide exploration of strategies for getting to zero greenhouse gas emissions by 2050.

My academic training focused on environmental science and energy transition modeling and analysis. I hold a Ph.D. in Environmental Engineering and Biogeochemistry from Cornell University and a B.A. in Chemistry from Colby College. I was also a fellow at the Bentley University Center for Integration of Science and Industry.

Q. Dr. Walsh, have you previously testified before or been otherwise involved in proceedings overseen by the Rhode Island Public Utilities Commission ("PUC")?

A. I have not previously testified before the PUC. I am currently participating as an expert consultant on behalf of the CLF and the Sierra Club, who are stakeholders in the PUC's "Future of Gas" Investigation (Docket No. 23-01-NG). I also serve as a member of the investigation's Technical Working Group.

Q. Dr. Walsh, on whose behalf are you testifying in this case?

A. I am testifying on behalf of the Conservation Law Foundation.

<u>Dorie K. Seavey</u>

Q. Dr. Seavey, please state your name, title, and employer.

A. My name is Dorie Seavey. I am a Senior Research Scientist at Groundwork Data.

Q. Dr. Seavey, please summarize your professional and educational experience.

A. I am an applied research economist and consultant. I received a Ph.D. in Economics from Yale University. I also hold a Master of Science in Economics from the London School of Economics and a Bachelor's Degree from Stanford University. My current work focuses on complex energy systems change with an emphasis on the future of natural gas. I am the author of three studies on gas distribution systems and a co-author of a study on solutions to the energy transition for low-income households. A copy of my curriculum vitae is attached.

Q. Dr. Seavey, have you previously testified before or been otherwise involved in proceedings overseen by the Rhode Island Public Utilities Commission ("PUC")?

A. I have not previously testified before the PUC.

<u>Joint Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to show that the Company's FY2025 Gas Infrastructure Safety and Reliability (ISR) plan is not aligned with the 2021 Act on Climate and the PUC's mandate to ensure affordable service through prudent system planning.

The Company proposes to spend $118 million on investments in FY2025 to modernize the gas system. A portion of these investments is necessary to ensure the safe and reliable operation of the gas system over the coming years while it continues to support Rhode Island's energy needs. We acknowledge such investments to be prudent. However, as RI moves beyond gas to fulfill the requirements of the 2021 Act on Climate, the gas system will be greatly underutilized compared to today. This leads us to question the prudency of some system modernization projects.

This testimony shows that there are alternative strategies to the pipeline replacement proposed in the ISR that can be used to reduce costs and ratepayer burdens while accelerating actions needed to achieve the emissions limits set by the Act on Climate.

Q. How is your testimony organized?

A. Section III explains how the ISR is not aligned with the Act on Climate. Section IV discusses how the ISR can be aligned with the Act on Climate in the context of the need to manage a transition beyond gas. This section introduces and defines the concept of segment decommissioning as a non-pipeline alternative to avoid gas system costs while accelerating emissions reductions. Section V presents a case study of how an ISR pipe modernization project could be selected and evaluated for segment decommissioning strategies. Section VI summarizes the testimony and offers recommendations.

III. THE ISR AND THE ACT ON CLIMATE

Q. How does the 2021 Act on Climate relate to the PUC's ISR Planning Process?

A. The 2021 Act on Climate (the "Act" or the "Act on Climate") established statutory enforceable greenhouse gas reduction mandates: 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and achievement of "net-zero" greenhouse gas emissions by 2050.

The Act also empowered the Executive Climate Change Coordinating Council ("EC4") to develop a plan by the end of 2025 that is informed by public comment and includes strategies and policies to meet the aforementioned targets. The Act further requires that the plan ensure an equitable transition for environmental justice populations and support workers during the transition.

While the planning process has yet to commence, the Act aligns RI with global goals to both *limit* (via the interim targets) and eventually *stop* (the net-zero target) emissions to avoid the worst impacts of climate change.

The understanding of the actions needed to achieve net-zero emissions by 2050 is constantly evolving, and the EC4 will have a substantial influence in setting RI's direction and how it defines "net zero". However, pertinent to this proceeding, the current scientific consensus is that global net-zero emissions require a substantial reduction in the use of gaseous and liquid fuels via the electrification of end-uses, including space heating.[1] This is corroborated by national scale

[1] Azevedo, Inês, Christopher Bataille, John Bistline, Leon Clarke, and Steven Davis. "Net-Zero Emissions Energy Systems: What We Know and Do Not Know." *Energy and Climate Change* 2 (December 1, 2021): 100049. https://doi.org/10.1016/J.EGYCC.2021.100049.

pathways analyses,[2,3] as well as those conducted in neighboring states with similar context to RI.[4,5] Alignment with the Act thus requires a substantial reduction in gas consumption and customer counts.

In addition to reducing combustion, the Act on Climate and the current accounting framework employed by RI also necessitate efforts to reduce methane emissions from various sources, one of which is the gas pipeline distribution network, inclusive of the buildings and end-use equipment that it serves.

Q. Are there findings from Commission Docket 23-01-NG (RIPUC's "Future of Gas" Investigation) that can be informative here?

A. On February 6, 2024, the technical consultant for the investigation delivered to the Investigation's stakeholder committee a set of draft results.[4] The results are preliminary and are still pending feedback from the Investigation's stakeholder committee. However, there are several findings that are relevant to the ISR and the role of the gas system in the context of the Act on Climate:

1. Increasing investment in the gas system through mechanisms such as the ISR will steadily increase the Company's revenue requirement leading to higher customer costs.[5]
2. Continued use of utility gas at current scales faces significant challenges due to the costs of and barriers to decarbonizing utility gas.[6]

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[2] E. Larson, et. al Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report, Princeton University, Princeton, NJ, 29 October 2021 dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20%2829Oct2021%29.pdf?dl=0

[3] Browning, Morgan, James McFarland, John Bistline, Gale Boyd, Matteo Muratori, Matthew Binsted, Chioke Harris, et al. "Net-Zero CO2 by 2050 Scenarios for the United States in the Energy Modeling Forum 37 Study." *Energy and Climate Change* 4 (December 1, 2023): 100104. https://doi.org/10.1016/j.egycc.2023.100104.

[4] See Exhibit CLF-1-1: RI Investigation into the Future of the Regulated Gas Distribution Business: Technical Analysis Draft Results in PUC Docket No. 23-01-NG. Feb. 13, 2024

[5] CLF-1-3 Slides 14-16 (for summary), 43-51 (for detail)

[6] CLF-1-3 Slides 70, 71, 78

3. Strategies that downsize gas consumption yield lower costs. Such strategies include targeted electrification and segment decommissioning by avoiding proposed ISR investments. For example, the study showed that halving ISR work resulted in a one-third reduction in the revenue requirement in 2050.[7]

Q. The Company claims several times (e.g., Cover Letter, Page 30 of the main filing document) in the ISR Plan that the Proactive Main Replacement Program supports the Act on Climate. Are these claims accurate?

A. No. The claims, at best, represent a limited and incrementalist understanding of the actions that are needed to reduce and eliminate emissions as required by the Act on Climate. Achieving net-zero requires system-change actions that effectively eliminate, rather than reduce, emissions.

There are two issues with the Proactive Main Replacement Program ("PMRP") and how it relates to the Act on Climate. The first problem relates to how fugitive methane is estimated and accounted for, and how such accounting frameworks are used for planning. The second relates to the need to substantially reduce emissions from the combustion of utility gas to meet the limits established by the Act on Climate; continued investment in the gas system at current scales without a plan to downsize the gas system is incompatible with these limits.

Q. Would you please elaborate on the issues associated with fugitive methane emissions?

A. The goal of the PMRP as it relates to greenhouse gas emissions is to eliminate old leak-prone pipe by replacing it with modern pipe. This allows the State, in its greenhouse gas inventory, to claim a reduction in fugitive methane emissions. However, it is important to note that this "accounting book" reduction may differ from reality and is likely to undercount emissions.

[7] CLF-1-3 Slides 17-19

To explain why, it is helpful to first describe the differences in how emissions from energy consumption and emissions from gas networks are accounted for. The amount of emissions from fuel consumption is certain because the emissions generated from combustion are a defined metric (emission factor) with a high level of certainty based on the chemical properties of the fuel.

In contrast, the emissions factors used to calculate fugitive methane emissions are coarse estimates.[8] Leaks from gas distribution equipment are stochastic, meaning that they can vary across space and time. For a variety of reasons (e.g, corrosion, physical damage), fugitive emissions from a pipe segment could be very different from a neighboring pipe segment even if the characteristics of the two pipe segments were similar (e.g., material, vintage). The emissions factors used in DEM's accounts represent averages from studies that have tried to measure leaks across pipe classes. These studies typically show that older pipes, such as cast iron, tend to have higher average leaks across all pipes than more modern plastic pipes.[9] This is why cast iron pipes are considered "leak prone." However, some cast iron pipes may have low fugitive emissions, while others have very high emissions. The expectation is that the PMRP reduces these leaks on average—and the emissions factor estimates that average. This serves as the basis of the Company's claim that the PMRP reduces methane emissions and that it is aligned with the Act on Climate.

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[8] State-level inventory-based accounting, such as that used by Massachusetts and Rhode Island, uses standard length-based emissions factors (e.g., kgCH_4 released per foot of pipe or piece of equipment).

[9] Weller, Zachary D., Steven P. Hamburg, and Joseph C. Von Fischer. "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems." *Environmental Science and Technology* 54, no. 14 (July 21, 2020): 8958–67. https://doi.org/10.1021/ACS.EST.0C00437/ASSET/IMAGES/LARGE/ES0C00437_0006.JPEG.

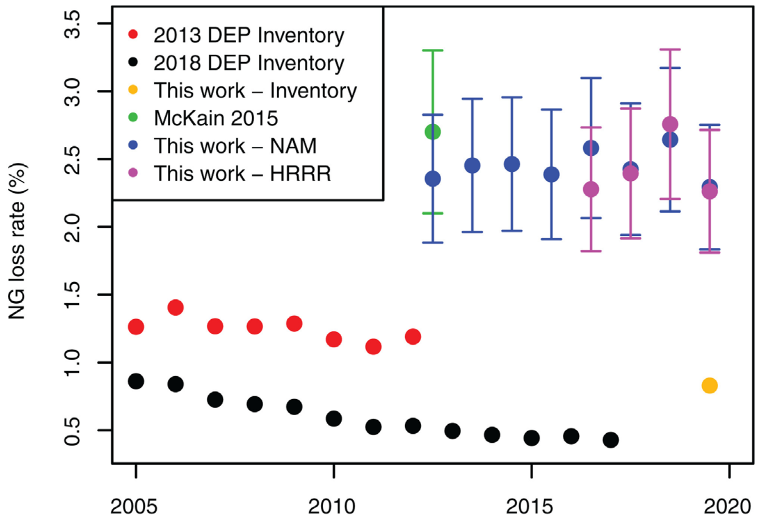

Figure MJW-1. Illustration of various estimates for natural gas leaks sourced from Sargent et al. (PNAS 2022). Natural gas (NG) leak rates using GHG accounting by MassDEP in 2013 (red) and after a methodology change in 2018 (black), by a bottom up estimate in the work (orange), and top-down analysis using two methodological approaches (blue and purple) described in the paper.

However, there is emerging evidence that pipe replacement programs are not as effective as current accounting frameworks indicate, in part because standard pipe-specific emissions factors undercount methane emissions. Figure MJW-1 illustrates this point by comparing Massachusetts' inventory-based accounting, as reported by the MA Department of Environmental Protection, and emissions detected in the metro Boston region, as measured by Sargent et al.[10] As the high emissions-factor cast iron pipe is replaced with plastic pipe, the accounted emissions decline. In this statutory "accounting book" approach, emissions should steadily decline as leak-prone pipe is replaced, as reflected by the trend of the red and black dots in Figure MJW-1.

[10] Sargent, Maryann R., Cody Floerchinger, Kathryn McKain, John Budney, Elaine W. Gottlieb, Lucy R. Hutyra, Joseph Rudek, and Steven C. Wofsy. "Majority of US Urban Natural Gas Emissions Unaccounted for in Inventories." Proceedings of the National Academy of Sciences of the United States of America 118, no. 44 (November 2, 2021). doi.org/10.1073/PNAS.2105804118/SUPPL_FILE/PNAS.2105804118.SAPP.PDF

As Figure MJW-1 shows, and further detailed by its source, there is increasing evidence that such accounting approaches undercount methane emissions. Further, despite six years of accelerated pipe replacement in the Greater Boston region, Sargent and colleagues find that methane emissions failed to materially decline. The study indicated that part of this stability in light of efforts to mitigate emissions may be due to non-utility leaks from behind the meter, such as building distribution pipes and residential gas heating and cooking equipment. There is no practical strategy for managing such leaks beyond transitioning off utility gas. An additional, complementary explanation for the discrepancy could be that super-emitter leaks, not fully addressed by pipe replacement or repair programs, are under-identified and systematically larger than those selected to estimate the average emissions factors.

Q. Are there other considerations about methane that should inform the management of methane emissions from gas infrastructure?

A. While the PMRP is an important mechanism for maintaining system safety and reliability, its impact on methane emissions and its utility in achieving climate targets should be evaluated in the context of the warming dynamics of methane, the current scientific evidence regarding fugitive emissions from distribution systems, and the relative cost-effectiveness of different strategies for reducing and eliminating leaks from the gas distribution system.

Methane's contribution to climate change is widely misunderstood. Methane (CH_4) is a short-lived, potent greenhouse gas (half-life of 12 years) with complex dynamics. Reducing emissions today can significantly reduce near-term warming (the global warming potential of CH_4 is 84 greater than that of carbon dioxide (CO_2) over a 20-year time horizon), but has a lesser impact on long-term warming (CH_4 is 28 times more potent than CO_2 over a 100-year time horizon). Accounting frameworks, such as those used by the RI Department of Environmental Management ("DEM"), use the 100-year time horizon. Both are scientifically accurate metrics that describe two perspectives. If, instead the State were to use a 20-year time horizon, such a change would reflect a policy choice (or a value statement) that prioritizes a reduction in near-term warming over a reduction in long-term warming.

These time dynamics are often misunderstood. Prioritization of methane reduction strategies must occur in the context of how the methane is being emitted. Delaying a main replacement for several years to identify and evaluate an opportunity for ending gas service on that main will be far more effective in achieving the pace and scale of emissions reductions aligned with the Act on Climate.

Q. How does the PMRP relate to the Act on Climate in terms of the consumption of gas?

A. Consumption of gas at current levels is not compatible with the Act on Climate. The at-scale usage of an alternative pipeline fuel, such as renewable natural gas or hydrogen, is also not consistent with the scientific consensus of viable pathways to achieve net zero.[11]

It is conceivable that a small fraction of the gas consumed in Rhode Island today could be used in some limited applications even when the State achieves net zero (presumably if that usage is offset by carbon dioxide removal). There is consensus among regional decarbonization pathways studies that New England can affordably achieve its state's net-zero targets with modest consumption of gas for firm electricity.[12,13] Further, some building types may require the use of

[11] See Exhibit CLF-1-4: Executive Summary (Page 2), Emissions Considerations (Page 30-32), Costs (36-39), RNG Evaluation (Page 42-44)

[12] Jones, Ryan, et al. "Massachusetts 2050 Decarbonization Roadmap: Energy Pathways to Deep Decarbonization." Evolved Energy Research, 2020. https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[13] Mettetal, Elizabeth, Sharad Bharadwaj, Manohar Mogadali, Saamrat Kasina, Clea Kolster, Vignesh Venugopal, Ben Carron, et al. "Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future," www.energyfuturesinitiative.org/efi-reports

gas due to high energy demands or as a backup resource. A small gas system could be kept online for those entities.

However, the eventual large drop in gas demand presents a fundamental challenge for the distribution system as it stands today. As the gas customer base contracts and consumption falls, the fixed costs of maintaining the system are likely to stay relatively constant or increase which means that average distribution costs per customer and per therm will necessarily increase.

In addition to the Act on Climate, a complementary pressure on the RI gas system is unprecedented competition from more efficient, cleaner, non-gas technologies. These include induction stoves, electric heating equipment, and other technologies that increasingly offer consumers new value propositions relative to utility gas. Alternative gasses cannot meet these value propositions.

Further, a growing set of financial incentives are lowering the cost of these technologies and spurring the growth of industries that support the growth of these technologies and continued innovation. These include tax credits and rebates offered by the Inflation Reduction Act and rebates offered by the Company through its energy efficiency program.

For customers to “fuel switch,” they do not need these alternative technologies to reach cost parity with gas. Notably, only in the past two decades has utility gas become less expensive than oil. Prior to this, many customers adopted gas for other reasons, such as for cooking or to avoid the need for fuel delivery. However, there is a growing consensus, even among utilities, that the era of cheap utility gas is over. For example, see cost forecasts in Massachusetts's Future of Gas Investigation[14] and depreciation studies in New York State's Gas Planning Order.[15]

Competition from non-gas energy technologies will also put downward pressure on gas consumption and customer counts. In sum, while the ISR is predicated on continuing to invest in the gas distribution system, current market and technological forces fundamentally challenge the ability of traditional cost-of-service ratemaking to fully recover the cumulative revenue requirement associated with these investments.

Q. Can you please synthesize the impact of these points on utility customers?

A.

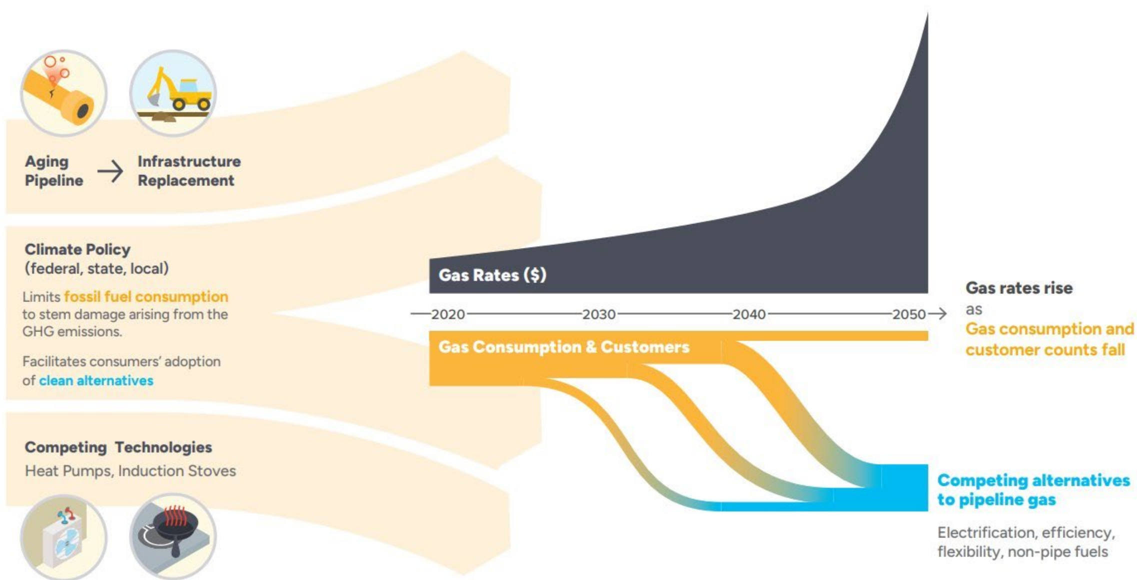

Figure MJW-2. Illustration of key drivers of future gas consumption and rates

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[14] MA DPU Docket No. 20-80
[15] NYS DPS Case 20-G-0131

Figure MJW-2 shows the influence of increasing pipeline replacement costs, climate policy, and competing technologies on the gas system. Fixed costs increase due to system replacement and modernization programs such as those under the ISR. This happens at the same time that an increasing number of customers begin to leave the system. Under current regulatory practices, this will necessarily lead to higher per-customer delivery costs (i.e., increasing per-customer revenue requirements) in order to provide cost recovery for the Company's capital spending, rate increases that will further incentivize customers to reduce consumption and leave.

Unless managed, the contraction of the gas system is likely to have distributional consequences. Non-migrating customers with less agency to leave the system will be disproportionately burdened (i.e., low-income households, renters, and populations with limited and delayed access to this information). In sum, a reduced-throughput distribution system exacerbates affordability challenges for the diminishing number of customers who remain reliant upon that system.

Q. Are these issues unique to Rhode Island?

A. No. Recent studies in New York[16] and Massachusetts[17] relying on utility-provided data show similar challenges for gas distribution systems as a result of climate policy and increasing competition from cleaner, more efficient energy technologies. Similar to Rhode Island, both of these states have relatively high levels of leak-prone gas distribution pipeline and have put in place strong net-zero targets.[18]

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[16] Walsh, Michael, and Michael Bloomberg. "The Future of Gas in New York State." Building Decarbonization Coalition, March 16, 2023. https://buildingdecarb.org/resource/the-future-of-gas-in-nys.

[17] Energy+Environmental Economics and Scott Madden Management Consultants. "The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report-Technical Analysis of Decarbonization Pathways," March 2022. https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf.

[18] PHSMA. "Cast and Wrought Iron Inventory," https://portal.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2FCI%20Miles%2FGD_Cast_Iron.

IV. ACTIONS NEEDED TO ALIGN THE ISR WITH THE ACT ON CLIMATE

Q. What is needed to achieve alignment with the Act on Climate while maintaining the PUC's mandate to ensure affordability, safety, reliability, and equity?

A. A managed transition is needed to accomplish these goals. The following is the current definition used by Groundwork Data to describe a managed transition:

> We define a managed gas transition as a strategic approach to an orderly phasing out of the use of utility gas in favor of clean energy sources in order to achieve state emissions goals while minimizing societal costs. Under a managed transition, geographically localized groups or blocks of buildings would be removed from the gas system and connected to non-GHG-emitting heating and cooling technologies. The conversions would be coordinated, cost-effective, and scalable instead of incremental, dispersed, and driven by individual customer economics. On the flip side, coordinated investments by diverse stakeholders —utilities, consumers, and government—are necessary to install the new appliances and equipment and to ensure that safety, reliability, and affordability are not compromised.

Further, Groundwork Data defines three key strategies needed for implementing a managed transition of the gas system:

- Halt growth of the gas system via fossil-fuel-free building codes and remove incentives for connecting new gas customers.
- Avoid reinvestment in the gas system by deploying non-pipeline alternatives as a substitute for replacing gas pipeline and related gas plant.

- Begin planning for zonal transitions off the gas system and develop long-term gas planning regulatory frameworks that address ratepayer impacts, strategies for managing the financial needs of the transition, and integrated gas and electric coordination.

The first two strategies are used to restrict or avoid investment in the gas system over the coming years. The third strategy seeks to ensure safe, effective, fair and equitable rightsizing of the gas system as customers depart.

Q. How could the FY2025 Plan better incorporate the principles of a managed transition beyond gas?

A. Opportunities for the ISR process to align with a managed gas transition involve avoiding reinvestment in the gas system through the adoption of non-pipe alternatives to proposed projects. A non-pipeline alternative ("NPA") is an intervention that allows a utility to avoid using traditional "pipe"-based projects to address certain infrastructure needs.[19] NPAs can include various strategies for managing gas supply and demand, such as energy efficiency, demand response, advanced leak repair, and segment decommissioning.

The definition of NPA varies by state and utility[20] but is broad and seeks to avoid large capital investments. The Company defined NPAs in its 2021-2023 System Reliability Procurement ("SRP") Three-Year Plan as an "inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment."[21] The PUC and the Company are recognized as a national

[19] Brutkoski, Donna. "It's Time to Consider the (Non-Pipeline) Alternatives." Regulatory Assistance Project, November 1, 2021. raponline.org/blog/its-time-to-consider-the-non-pipeline-alternatives/.
[20] Nelson, Ron, et al. "A Framework for Non-Pipeline Alternatives Analysis and Review of Existing Approaches." Lawrence Berkeley National Laboratory, November 2023. emp.lbl.gov/publications/framework-non-pipeline-alternatives.
[21] RIPUC Docket 5080 2021-2023 System Reliability Procurement Three-Year Plan, November 20, 2020

exemplar for incorporating NPA considerations into the SRP process. However, to date, RI's NPA approach has largely focused on aligning reliability and procurement with the Least-Cost Procurement Law.

The Company could expand these efforts to its ISR plan, by starting to identify and evaluate potential segments for decommissioning rather than pipeline replacement. Segment decommissioning may require a lead time to plan and engage with customers and thus cannot be practically implemented in the current FY2025 ISR plan. However, the current ISR could defer some projects to evaluate potential candidates for segment decommissioning.

Q. Please describe segment decommissioning.

A. Segment decommissioning involves terminating service on a segment of the gas system through a series of steps:

1. Conduct integrated gas and electric system planning to identify opportunities for segment decommissioning.
2. Retrofit gas-served buildings on the segment with equipment and energy sources that can provide an effective equivalent to or improvement over the existing gas services.
3. Remove gas meters and cap service lines.
4. Cap and abandon the pipe segment in place.

The term "targeted electrification" has also been used to describe segment decommissioning. The term "segment decommissioning" is a more inclusive term as it could include strategies such as non-pipeline fuels.

Q. What are the benefits of segment decommissioning related to the PUC's mandate to ensure prudent investment and affordable service?

A. Segment decommissioning is a type of NPA that avoids the need for pipeline replacement, which is expensive and disruptive. Typically, pipeline replacement requires trenching and installing new main and services, often by digging through pavement and yards. Often it requires the relocation of meter banks. Streetwork often requires a police detail, adding extra costs. Engineering planning, coordination with local governments, and permits are also required.

The FY2025 ISR proposes spending $62,169,000 to replace 32.8 miles of leak-prone pipe in the Main Replacement and Rehabilitation program. This suggests an average cost of $1.9M per mile.

Substituting segment decommissioning for pipeline replacement can avoid the costs described above. Comparatively, decommissioning a segment requires capping the ends of a pipe segment, which costs approximately $10,000.[22] Decommissioning meters at a building would also involve a modest cost.

Decommissioning will require that customers currently served by the main receive equivalent or improved energy services while also ensuring they are justly compensated for heating and cooling equipment and related assets that may be retired early. Decommissioning is best suited for situations where the associated cost savings reasonably justify the cost of changing energy services for the affected street.

Q. What parts of the system is segment decommissioning best suited for?

A. Segment decommissioning is suitable for segments with pipes that will need non-urgent replacement in the near future. These could include Proactive Main Replacement, City and State Public Works Projects, and Proactive Low-Pressure System Elimination Projects. Here, there is

[22] Petition of Liberty Utilities (New England Natural Gas Company) Corp. for Approval of its 2022 Gas System Enhancement Plan, No. 21-GSEP-04. Massachusetts Department of Public Utilities. Costs may differ by location.

both a justification for an intervention to avoid the cost of pipeline replacement and sufficient lead time to plan and implement an intervention. For example, thermal energy network pilot projects in Massachusetts[23] and New York typically have a 2-year lead time to plan, onboard customers, and construct the project.

Such a lead time may not be practical for more urgent reactive or priority proactive projects that address identified leaks or failing pipeline material.

Plastic and protected steel segments in a state of good repair generally have low risk and low maintenance costs; as such, there may be little need to decommission these segments. Here, customers can electrify at typical intervention points, such as equipment end of life or a major renovation. As sufficient customers exit, opportunities may emerge for zonal-scale decommissioning to manage issues related to declining consumption. We have not reached this point in the transition.

Project selection will need to consider the topology of the gas system. Hydraulic feasibility refers to the ability of a decommissioning project to not significantly affect the operations or reliability of the rest of the system. Terminal branches are likely to be the most practical for decommissioning, since decommissioning trunks that feed multiple branches and numerous customers would cut the customers on the branches off from the system.

Decommissioning will likely affect the reliability of some parts of the system. For example, if a street segment is served at two ends by separate feeder pipes and half the segment is

[23] Eversource. "Geothermal Pilot Project Updates." https://www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/geothermal-pilot-project.

decommissioned, the portion remaining on gas would likely provide less reliable service than before as it is only fed by one pipe. However, this is already the situation for many terminal branches of the system. Thus, reliability impacts need to be evaluated on a spectrum to assess the probability of a change in risk.

Q. What other factors could influence the siting of segment decommissioning projects?

A. Selection of segment decommissioning should also take into account:

1. What options exist for transitioning buildings off gas, and what are the relative costs of such options?
2. What is the state of the local electric distribution system? What amount of heating electrification can it support? Is it slated for an upgrade in the near future?
3. What is the ability to support advanced electrification strategies: ground-source heat pumps, water-source heat pumps, or waste heat recovery?
4. Sociodemographic factors: How will the project affect the local community? Are there burdens or benefits that are relevant to historically disadvantaged communities that should be considered?

Q. What are the benefits of segment decommissioning as it relates to the 2021 Act on Climate?

A. Segment decommissioning of the gas system would deliver a significant reduction in greenhouse gas emissions by electrifying most or all energy end-uses. In other words, it offers a meaningful opportunity to accelerate emissions reductions to align with the Act on Climate's interim and 2050 limits.

Q. Are there any other benefits of segment decommissioning?

A. Yes. Project coordination across multiple buildings can lower the costs of building-side segment decommissioning strategies. These benefits are likely to be incurred in the following categories:

- Customer acquisition costs
- Bulk ordering discounts
- Contractor site and travel costs
- Municipal permitting costs
- Project evaluation and management costs
- Acceleration of electrification co-benefits: health, safety, and comfort.

For example, rig transport and setup are significant cost drivers for individual geothermal projects. Sequential drilling in a neighborhood could be a major source of cost savings for such projects.

Q. What are the implications for the electrical distribution system?

A. Electrifying a street segment can have implications for the electric distribution system. A formal power flow analysis can identify any potential upgrade needs. The impacts are likely to be seen at two levels.

The first is local neighborhood equipment. This includes services and transformers that may need to be upgraded to handle the increased load. The second is the primary feeder line connecting such equipment to the substation. Such feeders serve a wider number of customers in the area, and the ability of the feeder to handle load increases depends on the state of the feeder and the forecasted loads that it serves. Distribution-related equipment may need to be upgraded in any case due to future heating electrification, electric vehicles, and distributed solar installations.

Q. Would segment decommissioning constrain customer choice?

A. In many situations, no. Generally, electric alternatives provide similar or improved energy service over gas. The heating service provided by air-source heat pumps is sufficiently similar to that provided by a gas furnace or boiler while using ductless mini-splits can offer more customizability and zoning control. Electric induction cooking is widely considered to be superior to gas. A recent model includes in-element temperature sensing for precise control and can be installed on a 120V outlet.[24] Electric fireplaces offer a greater degree of ambiance customizability.

Customers would still have access to delivered fuels such as propane, which is a substitutable product for utility pipeline gas. Using air-source heat pumps in a hybrid arrangement with propane is a common arrangement in the Northeast. Most existing gas equipment can use propane with minor modifications to burner tips. If a customer desires to cook with gas, use a fireplace, or maintain some aspects of fuel-based heating systems, they can. Some sites may face constraints on the placement of a propane tank, which may limit its ability.

Q. Would customers be forced to retire their assets prematurely?

A. Not necessarily. By converting some appliances to propane, customers can still use existing appliances. This can be advantageous for the time being if the customer has recently installed a high-efficiency gas furnace or boiler. Following propane conversion, this equipment can be run in a hybrid heating mode with a ducted or ducted heat pump system. Customers may also keep their gas stoves, if they prefer.

Q. Are there benefits of maintaining such assets on a street segment?

A. Maintaining efficient gas assets through their remaining life span can have the benefit of lowering peak heating loads that may challenge distribution systems at or near capacity. Depending on rate design and future rates, operating a heating system in hybrid mode could stabilize heating costs

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[24] See: Impulse Labs https://www.impulselabs.com/

and insulate a customer from large electric demands on peak heating days when heat pump efficiency may decline.

Q. Are other states/jurisdictions considering segment decommissioning strategies?

A. Yes. California and Massachusetts have begun to actively consider segment decommissioning.

The California Energy Commission sponsored Gridworks, E3, and Ava Community Energy to conduct a Targeted Building Electrification and Gas System Decommissioning Project. The goals of this project are to develop a framework to identify and evaluate opportunities for segment electrification, identify potential pipeline segments for decommissioning, engage with local communities on the potential pilot projects, and conduct education and outreach to key stakeholders and policymakers. The project seeks to identify three locations for pilot projects. Two studies by E3 have been produced:

- Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California[25]
- Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California[26]

In Massachusetts, two segment transition studies have been conducted, one in the context of municipal planning and the second in the context of the state's leak-prone pipe replacement efforts. Both these studies have shown significant cost savings from targeted avoided pipeline

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[25] Kahn, Matthew. "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California," September 2023. https://gridworks.org/wp-content/uploads/2023/06/Evaluation-Framework-for-Strategic-Gas-Decommissioning-in-Northern-California-Interim-Report-for-CEC-PIR-20-009.pdf

[26] "Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California." Energy and Environmental Economics, Inc., Gridworks Organization, East Bay Community Energy, December 2023. https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf.

replacement with long-term customer benefits. The final order of the Department of Public Utilities in the Massachusetts Future of Gas proceeding notes guidance from both the Attorney General's Office and the Department of Energy Resources regarding the development of an "alternatives investment calculator" or "geographical marginal cost assessment tool." The Order endorsed this concept and further directed the utilities to evaluate and include proposals for "targeted electrification" segment transition projects in future filings.

Q. Could you please walk us through an illustrative example of how a street segment could be selected for segment decommissioning projects?

A. Yes, please see the next section.

V. CASE STUDY OF SITE SELECTION AND ALTERNATIVES ANALYSIS FOR SEGMENT DECOMMISSIONING

Q. Please summarize your case study's analysis.

A. The analysis below is an illustrative "back of the envelope" estimation of the primary costs and emissions impacts of a decommissioning project for a street segment proposed for pipeline replacement in the FY2025 ISR. We evaluate three alternative scenarios that bookend the range of possible future-of-gas scenarios in order to illustrate the impacts of different intervention strategies.

We note that this analysis is a simple demonstration of the approach of site selection and evaluation. A more comprehensive analysis may find that this site may not be a priority or suitable for transition. Further, this analysis is preliminary and could be improved with better data from the Company and a more thorough review of public data. Still, it provides a useful demonstration of projects that could align the ISR more closely with the state's climate and affordability goals.

Q. How did you select an ISR Project?

A. We examined *ISR FY25 (Proposed Work) List of Projects for Reliability Planning, Low-Pressure Elimination, Main Replacement, Public Works* (Attachment DIV 1-23, Page 103 Book 2) for potential projects with the following criteria:

- ISR Program: Proactive MRP or LP (Low Pressure) Elimination
- Abandonment Material: Cast Iron, Bare Steel, Polyethylene
- Abandonment Size <= 6in

From this list we screened remaining segments for:

- In or near Justice 40 Census Tract[27]
- Minor or terminal street segments (hydraulically feasible)
- Predominantly single family homes

Q. Please describe the ISR Project you selected.

A. Our downscaling provided us with a number of streets. However, we ultimately selected the "Mitris" project in Woonsocket (Line 9 of Attachment DIV 1-23) with the following criteria:

- Installation Miles: 0.26
- Abandonment Miles: 0.26
- Abandonment Material: Polyethylene
- Abandonment Size: 6"
- # of Services: 14
- New Main Size: 2"
- Existing Main Pressure: LP (Low Pressure)
- New Main Pressure: 60 psig
- Project Cost: $290,707
- ISR Program: Proactive Low-Pressure System Elimination

[27] Council on Environmental Quality, Climate and Economic Justice Screening Tool. https://screeningtool.geoplatform.gov.

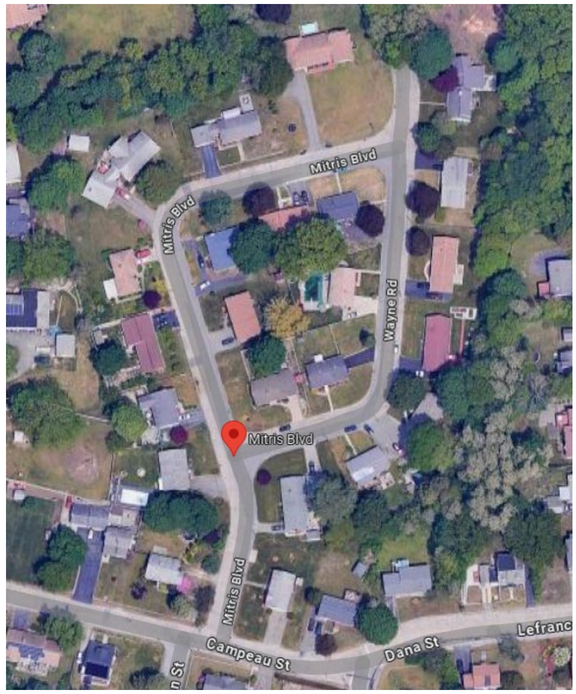

Figure MJW-3. Map of Mitris project location including Mitris Blvd and Wayne Rd (Woonsocket, RI)

A map of the project location is presented in Figure MJW-3. Measurement of street length indicates that the project includes Wayne Road, making the location a terminal branch of the gas system.

The ISR indicates that there are 14 services associated with this project. A review of the Woonsocket Parcel Database indicates that, of the 23 homes in this segment, 7 use oil and 16 use gas. Based on this, we assume 16 homes would be affected by the project and would require an intervention to decommission the segment in lieu of upgrading the pipe for higher pressure.

The distribution system feeder (#49_53_200W5) appears to have sufficient capacity to handle the electrification needs of 16 homes. Its 2022 peak demand was 71% of the summer rating and has little forecasted growth.[28] Notably, Google Street View's August 2023 capture shows a solar installation in progress.[29] Many of the homes on these streets are well situated for solar. Most plots appear to have sufficient space for a propane tank and geothermal equipment.

The census tract is identified as a disadvantaged community. The tract's racial and ethnic composition mirrors RI but has slightly more Black and Hispanic residents than the statewide share. The community is at the 70th percentile for income, which classifies it as a "low-income" tract.

Q. What assumptions, data and methods did you use for this analysis?

A. For our method, we applied a framework that Groundwork Data has developed called Local Energy Asset Planning ("LEAP").[30] Integrating otherwise disparate datasets, LEAP seeks to identify sites suitable for multiple building energy transition actions and to evaluate the impact of alternative strategies. Groundwork has applied LEAP to the identification and evaluation of segment decommissioning projects in Holyoke[31] and statewide for Massachusetts.[32]

Our data sources for this analysis include:

- *Building Costs:* RI Future of Gas Investigation (23-NG-01) Consultant Assumptions
- *Fuel Emissions Factors:* EPA[33]

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[28] Rhode Island System Data Portal | Business Partners | Rhode Island Energy (rienergy.com)
[29] 29 Mitris Blvd - Google Maps
[30] Walsh, Michael. "Local Energy Asset Planning." Groundwork Data, October 2022. https://www.groundworkdata.org/s/Local-Energy-Asset-Planning-v20221014-4.pdf.
[31] University of Massachusetts Amherst Energy Transition Institute. "Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency." *ETI Reports*, January 1, 2023. https://doi.org/10.7275/enzr-5311.
[32] Forthcoming report for the Massachusetts Department of Energy Resources.
[33] US EPA, "GHG Emission Factors Hub." epa.gov/climateleadership/ghg-emission-factors-hub.

- *Building Energy Demand Data:* RECS[34]
- *Building Descriptive Data:* Woonsocket Assessor's Database
- *Marginal Emissions Factors for Electricity:* Cambium[35]

Our analysis accounts for the marginal emissions created by the addition of new electricity demand. The marginal emissions model we use incorporates RI's renewable energy procurement strategy but may account for emissions differently than the GHG accounting methodology of the RI DEM. As a result, our modeling may overestimate emissions in the electrification scenarios compared to DEM's methodology.

Note also that this analysis analyzes whether the emissions reductions achieved by PMRP align with state-wide reduction goals. It is anticipated that faster relative reductions in emissions from the electric and transportation sectors, driven by RI's 100% renewable energy law, enable a longer timeline for reducing emissions from the building sector. However, this analysis demonstrates that segment decommissioning strategies can also be effective at accelerating emissions reductions.

Q. What non-pipe options did you consider for this street segment?

A. We evaluated four scenarios:

- *Continued Gas:* in which the gas pipeline is replaced and homes continue to use gas.
- *Unmanaged Electrification*: in which the gas pipeline is replaced, but homes steadily electrify at a pace that represents natural equipment stock turnover. Electrified buildings

[34] "Residential Energy Consumption Survey (RECS) - Energy Information Administration." https://www.eia.gov/consumption/residential/.
[35] NREL. "Cambium." https://www.nrel.gov/analysis/cambium.html.

also receive efficiency improvements, leading to a 30% reduction in heating demand.

- *Accelerated Electrification*: where the gas pipeline is retired, and homes are fully electrified with energy efficiency improvements. Electrified buildings also receive efficiency improvements, leading to a 30% reduction in heating demand.

- *Accelerated Dual Fuel - Tank*: where the gas pipeline is retired, and homes are retrofitted to operate in a dual fuel manner.

Q. Do the emissions reductions in these scenarios align with the Act on Climate?

A.

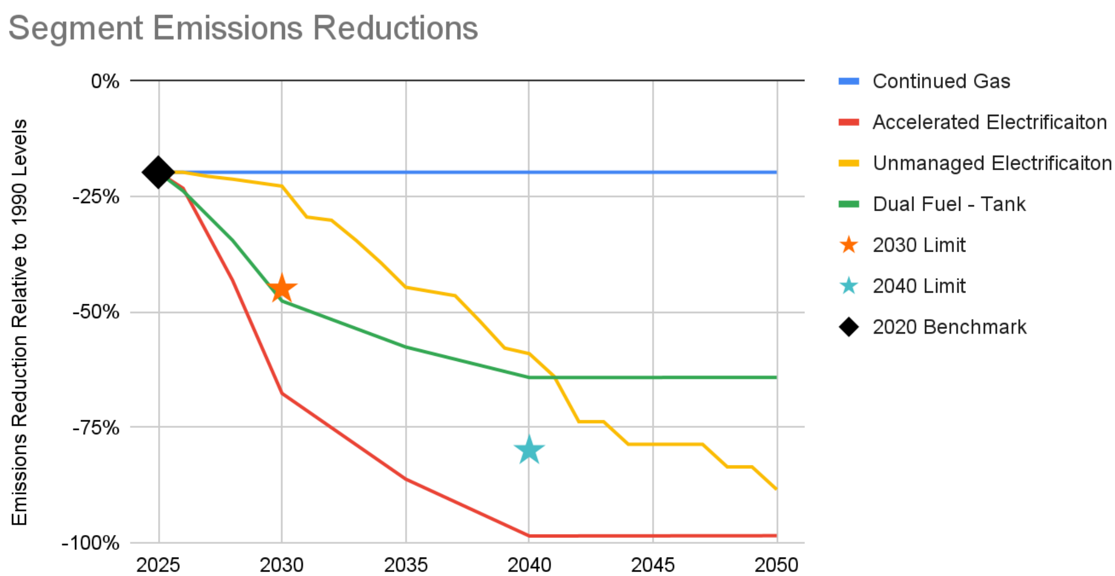

Figure MJW-4. Emissions reductions for each intervention strategy, 2025-2050.

Figure MJW-4 shows expected emissions reductions associated with each of the intervention strategies. Percent reductions are benchmarked to 1990 emissions at 0% and 2020 Emissions at 80%**.** The data aggregates combustion and fugitive emissions, and assumes a Global Warming

Potential (GWP) of 100 years for methane, consistent with the RI DEM accounting methodology. These results will be largely similar regardless of the street segment.

Of the four scenarios, the Accelerated Electrification scenario and the Dual Fuel - Tank scenario are the only ones that achieve the 2030 target. For 2040, the Accelerated Electrification scenario is the only one to achieve that year's limit and to approach the emissions reductions necessary for the state's 2050 emissions targets.

The Dual Fuel - Tank scenario may be a suitable strategy for avoiding pipeline replacement and advancing electrification, but it is feasible only in the near term. This finding is consistent with the preliminary findings of the consultant in the Commission's Future of Gas investigation.[36] Since the main replacement project involves replacing a plastic pipe with another plastic pipe, there is no emissions reduction impact since emissions factors are based on material only, even though the before and after pipeline pressures differ.

[36] PUC Docket No. 23-01-NG

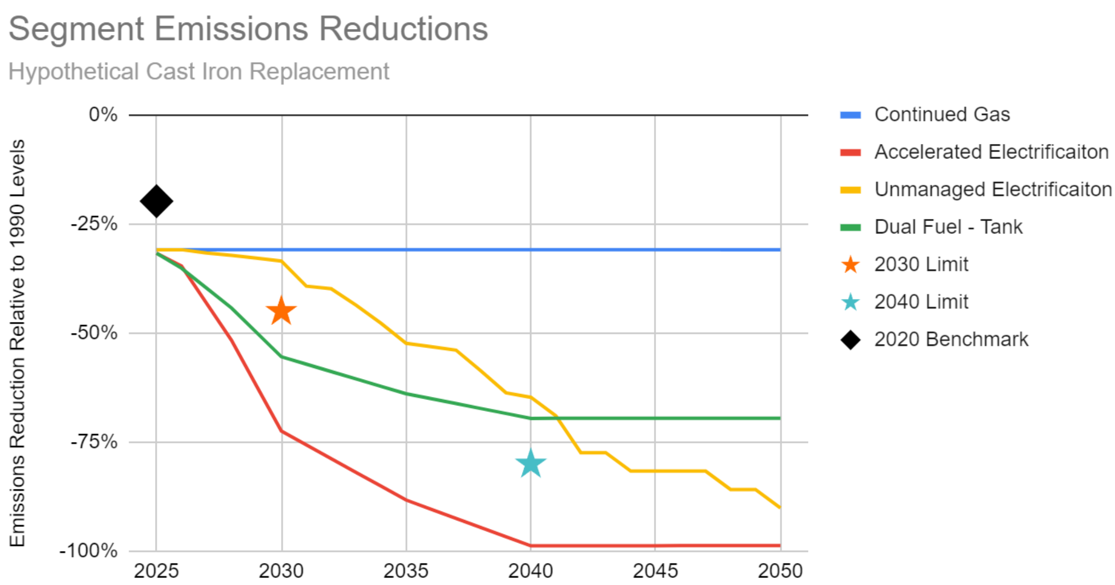

Figure MJW-5. GHG emission reductions for each intervention strategy assuming a cast iron segment replaced with a plastic pipe.

Figure MJW-5 shows the same street segment but assumes that the street segment is initially served by a cast iron pipe that is replaced through the PMRP. The emissions reductions realized by replacing the leak-prone pipe (difference between pre-intervention 2020 Benchmark diamond to values for each scenario in 2025) are a small fraction of the reductions ultimately needed to align the segment with the Act on Climate's limits.

Leak-prone pipe emissions are pernicious, but they constitute only a limited portion of the total greenhouse gas emissions associated with the RI's gas system. Thus, actions that reduce emissions, but maintain the system in perpetuity are not consistent with the Act on Climate.

Q. What are the building impacts and costs of each scenario?

A. A summary of the building impacts and costs is provided in **Table MJW-1**. Our cost estimates employ the same retrofit costs used by the technical consultant in 23-01-NG. We include total public incentives per household of approximately $15,000 (a combination of Clean Heat Rhode Island and Inflation Reduction Act subsidies).[37] This is likely on the upper end of incentives, but given the high proportion of low-income households in this community, this is a reasonable estimate.

Our analysis is inclusive of all gas-served equipment in each building: HVAC, domestic hot water ("DHW"), cooking, and clothes dryer. We also include low-cost envelope improvements that achieve a 30% reduction in heating demand. For simplicity, we present the cumulative streetwide cost associated with the retrofits. This is an analytical simplification. Segment decommissioning with accelerated equipment replacement may create some stranded equipment costs, our analysis incorporates this cost in the Early Retirement column.

Even with incentives, a home electrification retrofit with typical energy efficiency measures is likely to cost twice a like-for-like replacement of gas equipment. However, this per building incremental cost of $12,000 should be viewed in the context of gas system costs.

Table MJW-1 Summary of building intervention costs for the 16 considered buildings

Scenario	**Equipment Changes**	**Average Cost Per Building**	**Early Retirement**	**Average Cost Per Building w/Incentives**	**Cumulative Street Wide Costs**	**Cumulative w/Incentives**
Continued Gas	Like-for-like at end of life	$10,930	$0	$10,930	$174,884	$174,884
Accelerated	Electrification at	$35,043	$2,713	$22,756	$604,095	$364,095

[37] Based on available incentives from federal (Inflation Reduction Act and 25C tax credits) and state (RI Energy and Clean Heat RI programs) sources, we assume $15,000 available in incentives for whole-home electrification and $13,000 available for a dual fuel retrofit. We assume that such rebates will be available in perpetuity. It should also be noted that heat pump interventions offer enhanced comfort and well-being largely through the provision of cooling in the homes that currently do not have central cooling (about half the homes modeled). Adding comparable cooling to these homes would also incur a considerable cost, both in terms of the AC unit, but also in terms of ductwork. The additional cooling cost could easily exceed $5,000 per home, and customers would be steered to either installing mini splits or fully electrifying.

Electrification	decommissioning					
Unmanaged Electrification	Electrification at end of life	$35,043	$0	$20,043	$560,694	$320,694
Accelerated Dual Fuel Tank	Partial electrification with a non-pipe fuel at decommissioning	$29,901	$2,713	$19,614	$521,816	$313,816

Q. What are the gas system impacts and costs of each scenario?

A.

Table MJW-2 Summary of gas system impacts for the street segment

Equipment Changes	Applicable Scenarios	Upfront Utility Capital Cost	Per Building Cost
Pipeline replaced	*Continued Gas & Unmanaged Electrification*	$290,707	$18,169
Pipeline decommissioned	*Accelerated Electrification & Accelerated Dual Fuel - Tank*	$10,000	$625

Table MJW-2 shows the cost of pipeline interventions across the four scenarios**.** Avoiding pipeline replacement avoids significant implicit direct capital costs that average approximately $18,169 per household served by the pipeline segment. Pipeline replacement costs are treated as CapEx spending on which the Company typically collects a rate of return on equity of approximately 9.275%.[38] Thus, the total cost of such a project can be much higher. The entire rate gas customer base pays for this cost.

Regarding the decommissioning scenarios, we assume a $10,000 cost for digging, disconnecting, and pipe capping at the branch to Mitris Boulevard. This cost estimate is based on similar work conducted by Liberty Utilities in Fall River.[39]

[38] Page 18 of 4770-4780-NGrid-Ord23823-(5-5-20).pdf
[39] Petition of Liberty Utilities (New England Natural Gas Company) Corp. for Approval of its 2022 Gas System Enhancement Plan, No. 21-GSEP-04. Accessed June 28, 2023.

Q. What are the impacts and costs of each scenario's electric system?

A. Some instances of electrification may require upgrades to street transformers to handle increased peak loads.

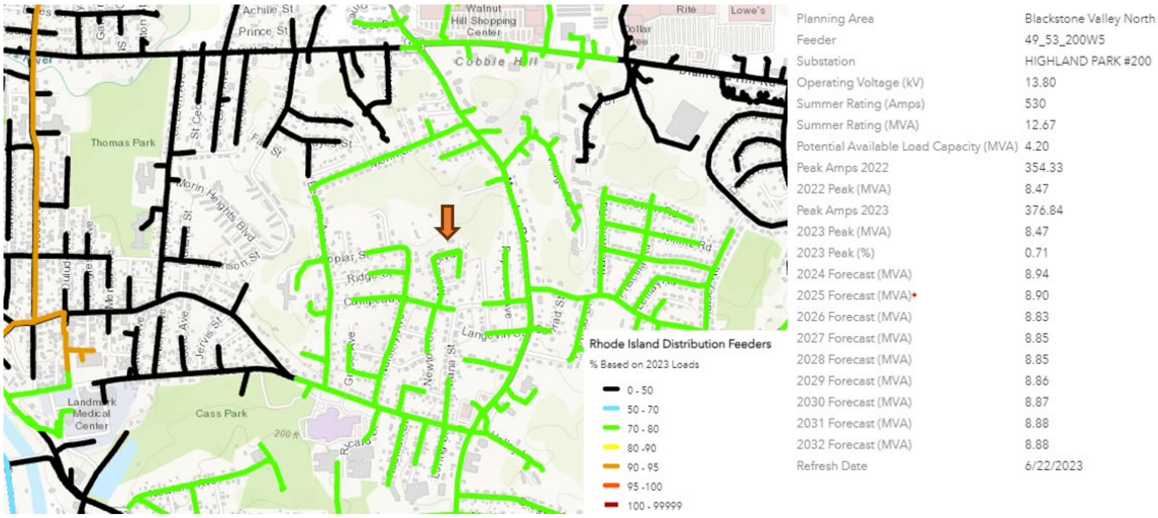

Figure MJW-6. Hosting capacity map (left) for the area surrounding Mitris Blvd. and statistics for the feeder serving Mitris Blvd. (right).

The feeder serving Mitris Blvd. appears to have sufficient capacity for the electrification of the segment Figure MJW-6. Recent peak and forecasted loads are well below the feeder's rated capacity. A more formal power flow analysis for the street segment should be conducted to determine if there are any locational voltage drop issues associated with the electrification of the street and what would be needed to address such issues.

While the number and capacity of transformers serving the street is unknown, based on prior modeling work leveraging NREL's ResStock database, we estimate the resulting peak load and the number of additional transformers a typical single-family neighborhood would need to serve the additional load.[40] We assume $20,000 for the cost of an additional transformer. Costs for each scenario are summarized in Table MJW-3.

Table MJW-3 Summary of gas system impacts for the street segment

Scenario	**Equipment Changes**	**Utility Cost**	**Per Building Cost**
Continued Gas	Like-for-like replacement of gas appliances does not necessitate electric system upgrades beyond historical normal operations	N/A	N/A
Accelerated Electrification	Immediate electrification of gas-connected buildings in 2025 necessitates electric system upgrades, likely requiring additional capacity of 1 to 2 more transformers	$20,000 - $40,000	$1,250-$2,500
Unmanaged Electrification	Gradual electrification of gas-connected buildings still necessitates electric system upgrades, but over a longer time horizon	$20,000 - $40,000	$1,250-$2,500
Accelerated Dual Fuel Tank	Hybrid heating configurations reduce the overall peak load of the system relative to full electrification, likely requiring 0 to 1 more transformer	$0 - $20,000	$0-$1,250

Q. What are the customer bill impacts?

A.

Table MJW-4 Summary of gas system impacts for the street segment

Building Intervention	**Monthly Heating + DHW Bill**	**Future Considerations (see 22-01-NG preliminary results)**
Gas (no efficiency gains)	$150	Gas bills are anticipated to increase multifold due to long-term cost challenges of the gas system and emissions costs.
All Electric with Energy Efficiency	$127	Electric costs are likely to increase modestly.
Dual Fuel - Tank (no efficiency gains)	$192	Propane costs are likely to increase due to emissions costs.

[40] University of Massachusetts Amherst Energy Transition Institute. "Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency." *ETI Reports*, https://doi.org/10.7275/enzr-5311.

Table MJW-4 shows the monthly heating and DHW bill for the three energy configurations considered. Electrification - along with moderate efficiency measures (30% savings) - reduces bills by approximately 15% relative to the Gas Case. In this instance, the efficiency measures drive the reduction in cost savings more so than the increased performance of a heat pump relative to a gas heating system. This analysis assumes an effective electricity billing rate of $0.255 per kWh and an effective gas billing rate of $0.072 per kWh, based on the average cost for the last 2 years, per EIA. Since the impact of efficiency measures will likely vary, it is possible that bills could go up modestly depending on the effectiveness of the energy efficiency measures. Improved building energy data (from meters or audits) could improve estimates.

The low-disruption dual-fuel tank scenario results in a bill increase because no energy efficiency is applied, and propane and electric heating are more expensive than gas (the analysis assumes $0.13 per kWh, also based on EIA historic averages). Had efficiency measures also been applied, monthly average bills would be lower and comparable to the gas and electric cases.

These results should be viewed in the context of the likely course of energy costs over the long term. As noted above, future gas commodity costs are expected to increase substantially and electric rates may also increase. Rate design can be used to make heating electrification more affordable.

Q. Can you summarize the analysis?

A.

Table MJW-5 Summary of results.

Scenario	Building	Gas System	Electric System	Total Spending Costs	GHG Implications	Bill Implications

Continued Gas	Gas-for-gas replacement at furnace/ boiler end of life $174,884	Pipeline Replaced $290,707	No upgrade needed	*Medium* $465,591	*Highest* Inconsistent with climate targets.	Near term: low Long term gas costs increase due to emissions costs, increased revenue requirement, declining customer base.
Accelerated Electrification	Full elec. in 2025 $364,095	Decommission Pipeline $10,000	$20,000-$40,000 for transformer in 2025	*Low* $394,095 - $414,095	*Lowest* Site emissions are eliminated in 2025.	~15% decrease upon electrification, modest increases over time.
Unmanaged Electrification	Full elec. at at furnace/ boiler end of life $320,694	Pipeline Replaced $290,707	$20,000-$40,000 over time	*Highest* $631,401 - $651,401	*Low* Buildings fully electrified by 2050, interim targets missed.	~15% decrease upon electrification, modest increases over time.
Accelerated Dual Fuel Tank	Dual fuel in 2025 $313,816	Decommission Pipeline $10,000	$0-$20,000 for transformer in 2025	*Lowest* $323,816 - $343,816	*Medium* Interim targets achieved, but additional intervention necessary to achieve 2050 target.	Near term: highest due to cost of propane. Long term: propane costs increase due to emissions costs.

A summary of the results is shown in Table MJW-5. The key takeaway of this illustrative exercise is that these buildings will need to be electrified in the future for the segment's emissions to align with the Act on Climate's limits. While electrifying today accelerates the investment in buildings, it avoids reinvestment in the gas system that will be underutilized relative to today. While customers will see an increase in energy bills, they will be insulated from the long-term costs of the gas system forecasted in the PUC's Future of Gas Technical Analysis Draft Results.[41] For some buildings, propane conversion may be advantageous in order to avoid the high cost of electrification when there is opposition to building electrification or where new, efficient gas equipment is in place.

Q. Can RI's Benefit-Cost Analysis Framework be used to evaluate results from an analysis of segment decommissioning alternatives?

[41] CLF-1-4 Slide 41

A. Yes. RI's Benefit Cost Analysis Framework can be used to evaluate results. However, the PUC should consider potential data needs and analytical limitations associated with the application of that framework to pipeline decommissioning. No single metric should be used to determine whether or not a project is suitable.

A formal Benefit-Cost analysis is challenging because of the large number of potential implementation strategies and underlying assumptions that need to be made across buildings, the electric network, and the gas distribution system. For example, an intervention may be optimized when some buildings partially electrify (a dual-fuel approach) and others wholly electrify. Alternatively, with electrification and electric system upgrades serving a more flexible load base, the assignment of costs can become incredibly challenging. For example, electric system upgrades necessary for electrification would also cover the upgrades needed for EV charging. Still, disciplined Benefit-Cost Analysis can be used to provide guidance and design support for the identification of optimal strategy mixes.

Q. Are there other projects in the ISR that could be suitable for segment decommissioning?

A. Yes, it is very likely that the ISR contains other proposed projects that would be suitable. The information provided in the ISR project list, however, is insufficient for making this determination conclusively. In many cases, projects are defined by just a street name, and the buildings impacted are not discernable. Some reported projects are large with over 100 service connections and appear to involve multiple streets in addition to the ones named. Within these larger projects, there may be suitable street segments for segment decommissioning.

A quick look highlights a notable opportunity. Line 55 of the project list identifies a project in Woonsocket in which 0.07 miles of cast iron pipe are to be replaced for one service at a project cost of $50,129. While the exact building could not be identified, all buildings on the street appear to be small-to-midsize single-family homes in which the cost of leaving gas is likely less than the cost of the project, and even more so with available subsidies, even if the cost of decommissioning is included (say ~$10,000-$20,000).

Additional projects could be identified using improved data from the utility and municipalities (e.g., improved assessment data). Our work referenced above addresses these data needs.

VI. CONCLUSION & FINAL RECOMMENDATIONS

Q. Please summarize your testimony.

A. A reduction in the use of gas and the size of the gas system is necessary to comply with the emissions reductions mandated by the 2021 Act on Climate. Segment decommissioning in lieu of pipeline investment can be an effective strategy for accelerating emissions reductions while avoiding projects that are likely to be underutilized and possibly stranded.

Q. What recommendations do you have for the PUC?

A. The PUC and the Company should seek to advance segment decommissioning as an NPA to align infrastructure, safety, and reliability needs with the emissions reduction mandates of Act on Climate.

Executing a segment decommissioning project as part of the FY2025 ISR is likely impractical at this point, due to the need for project lead time. However, a number of pipeline replacement projects proposed in the current ISR could potentially be deferred as the PUC and Company determine the details of how segment decommissioning could be achieved. Such details could include:

- Development of a more refined cost-benefit analysis with evaluation criteria defined with stakeholder input
- Identification of priority sites for segment decommissioning
- Clarification of issues related to the Obligation to Serve
- Development of a customer communication and onboarding framework
- Assessment of customer stranded assets, including potential compensation
- Evaluation of options for project funding.

Q. Should the PUC or the Company wait until after its "Future of Gas Proceeding" (Docket No. 22-01-NG) to advance segment decommissioning projects in future ISR plans?

A. No. The PUC does not need to wait and can start aligning the Company's ISR with the Act on Climate.

Over the last decade, public utility commissions across the country have generally approved gas utility requests for rate hikes and capital expenditures to replace aging gas infrastructure. However, regulatory commission rulings in 2022 and 2023 in Colorado, Illinois, Michigan, and Minnesota suggest that going forward, utility requests for rate hikes and capital spending may receive increased scrutiny. Illinois is the most significant and recent example. In its 2023 rate case orders for the state's four largest investor-owned gas utilities, the ICC disallowed gas utility spending requests for each company and reduced proposed rate hikes, sending a strong message of tightened regulatory oversight.[42] Total rate hikes for the four companies were cut by $300 million and rate base increases tied to capital spending were reigned in by $677 million, or about 40%.[43] The ICC found that the LDCs did not provide sufficient justification for the full amounts requested. In the case of Peoples Gas, the ICC disallowed $265 million in capital spending and ordered a new investigation of the company's infrastructure replacement program. The ICC's landmark order is an example of more proactive regulatory management in the scrutiny of investments at a time when the future of gas is highly uncertain.

As the draft results of RI PUC's Future of Gas investigation show, along with the above case study, there is a substantial benefit to avoiding reinvestment in the gas system for customers and

[42] Illinois Commerce Commission, Rate Cases Orders in Dockets 23-0066, 23-0067, 23-0068, 23-0069 (November 16, 2023).
[43] Calculations by GWD based on ICC rate case orders from November 2023.

for alignment with the Act on Climate. Guidance from the PUC to the Company thus can be provided now and need not wait until after the Future of Gas investigation is complete.

Q. Does this conclude your testimony?

A. Yes