Into Thin Air

How Leaking Natural Gas Infrastructure is Harming our Environment and Wasting a Valuable Resource

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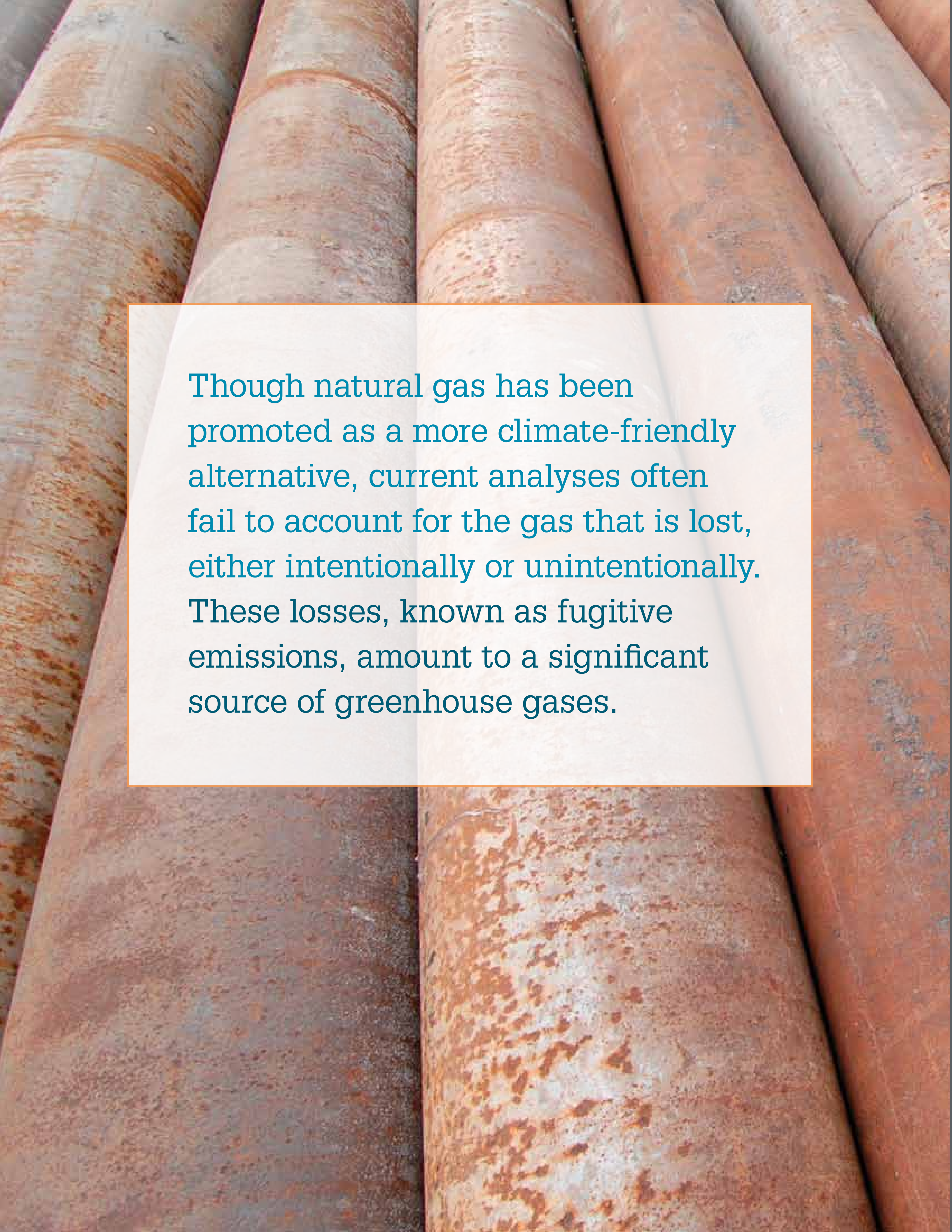

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Into Thin Air:

How Leaking Natural Gas Infrastructure is Harming our Environment and Wasting a Valuable Resource

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INTRODUCTION

Though natural gas has been promoted recently as a more climate-friendly alternative to coal and other fossil fuels for electricity, heating and transportation, current analyses of the life cycle emissions from natural gas often fail to account for the gas that is lost, either intentionally or unintentionally, during production, gathering, transmission and distribution.[1]

Leaking pipelines are estimated to release between 8 and 12 billion cubic feet of methane annually in Massachusetts alone. Yet, current state and federal policies actually provide disincentives for pipeline owners to aggressively find and fix these leaks

These losses, known as fugitive emissions, comprise a significant source of greenhouse gases that must be properly quantified and mitigated to ensure that our policies towards natural gas are congruent with Massachusetts' climate change mandates.[2]

A recent study from Boston University researchers highlighted the impacts of methane emissions from the region's antiquated natural gas pipeline infrastructure.[3] Not only do leaking pipelines pose a threat to public safety, they are estimated to release between 8 and 12 billion cubic feet of methane (the main constituent of natural gas) annually in Massachusetts alone.[4] Yet, current state and federal policies actually provide disincentives for pipeline owners to aggressively find and fix these leaks. In addition, there is no reliable methodology for calculating the actual amount of "Lost and Unaccounted for Natural Gas"[5] that escapes from the transmission and distribution pipelines which makes it difficult to evaluate the magnitude of the issue from a greenhouse gas perspective. As a result, this avoidable source of methane significantly adds to the aggregate of greenhouse gas emissions and is a major contributing factor to the impacts of climate change in the region and globally. Not only is this a source of emissions that could easily be tackled, but addressing it will conserve a valuable resource and reduce ratepayer costs. This paper calls for action to (1) increase the accuracy of reporting methane emissions from natural gas infrastructure and (2) adopt policies that promote accelerated repair and replacement of infrastructure to reduce methane emissions and reduce the costs for lost and unaccounted for gas.

SCOPE

Methane leakage from natural gas systems is an issue that is beginning to gain much more widespread attention in the United States, especially now that the Environmental Protection Agency has begun to require mandatory reporting and regulation of these emissions;[6] however, the problem has been well known for decades, and voluntary and market mechanisms have been developed on a national and international scale. For example, the Global Methane Initiative[7], which evolved from the Methane to Markets Partnership, and the EPA's Natural Gas Star Program have been working cooperatively with the U.S. oil and gas industry since as early as 1993 to develop cost-effectiveness technologies for reducing methane emissions from every stage of oil and gas

Methane leaks as mapped across the City of Boston by Boston University Professor Nathan Phillips. Phillips and his colleagues identified 3,356 leaks with methane concentrations exceeding up to 15 times the global background level.

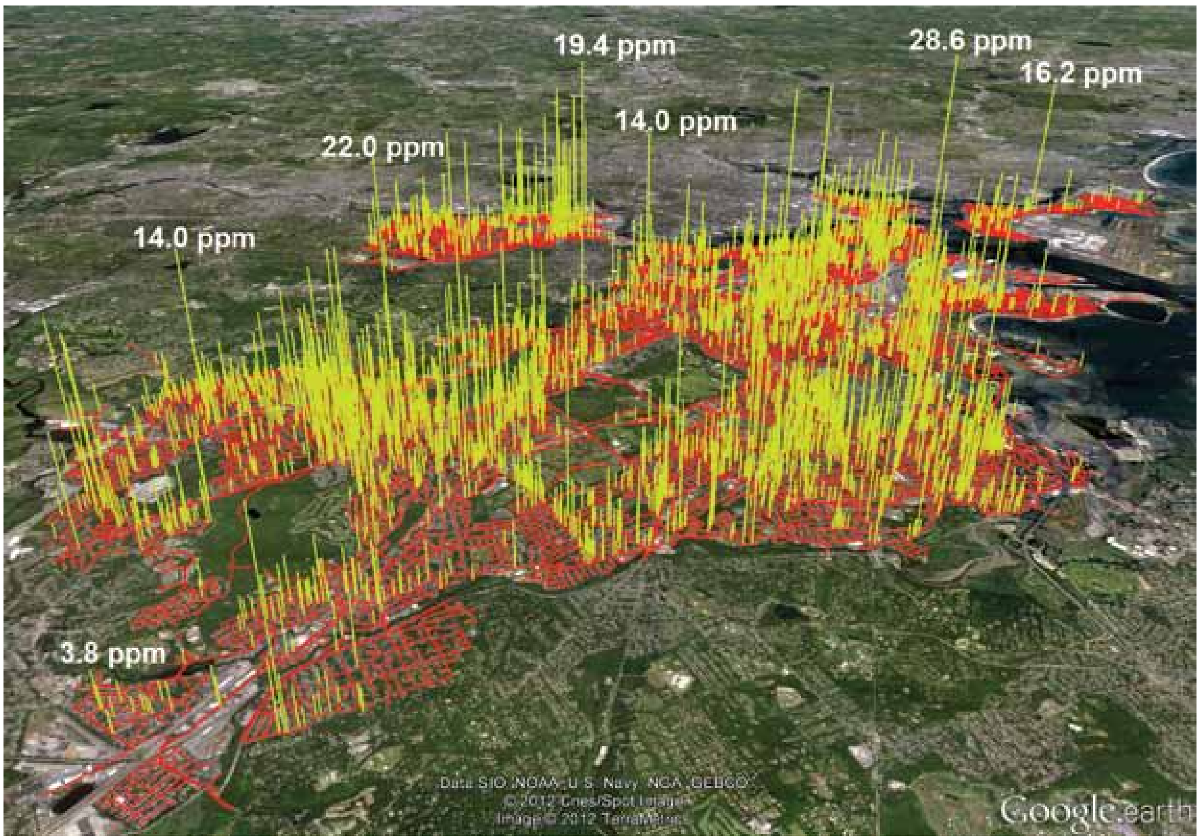

Image by Nathan Phillips.

development.[8] Though each of these initiatives includes fugitive emissions from distribution pipelines, the focus tends to lie upstream at the production and processing stages, in part, because existing cost recovery mechanisms for distribution companies negate the profit incentives that exist for operators at the production and processing level. In Massachusetts, however, there are no production wells and very little processing occurs; in addition, transmission lines are primarily regulated and overseen by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the Federal Energy Regulatory Commission ("FERC"). Therefore, Massachusetts's primary jurisdiction over methane leaks lies with the intrastate distribution pipelines that deliver natural gas from transmission lines into homes, businesses and institutions within the Commonwealth. This paper focuses upon opportunities to reduce emissions from these distribution pipelines which are subject to oversight by the Massachusetts Department of Public Utilities and the Massachusetts Department of Environmental Protection.

Massachusetts, and New England, sit in a unique position in the nation. Already, the New England power grid relies upon natural gas for a significant portion of its capacity, and the use of natural gas for electricity is expected to rise by almost 20% between now and 2020 as older, inefficient coal and oil plants retire.[9]

As a result, industry and some major end-users (including states) are clamoring to expand natural gas infrastructure.[10] Building new transmission lines and new gas generation promises to be a costly endeavor, and reducing leaks while increasing the efficiency of existing infrastructure, including storage, could provide a more cost-effective, environmentally beneficial means of providing excess capacity.

Massachusetts already has in place aggressive energy efficiency programs. For example, in 2010, Massachusetts natural gas efficiency programs saved 1,097 MMcf of natural gas. But in the same time period, Massachusetts lost, at a minimum, 1,725 MMcf through leaks on the system. We are losing more on the distribution than we are saving, and customers are still paying for those losses.

Before we invest in costly new transmission lines and other natural gas infrastructure, we must address these avoidable system losses, and we must increase the efficiency of the existing system. Otherwise, we will continue sending a valuable resource into thin air.

Global Methane Initiative and the EPA's Natural Gas Star Program have been working cooperatively with the U.S. oil and gas industry since as early as 1993 to develop cost effective technologies for reducing methane emissions.

BACKGROUND ON DISTRIBUTION INFRASTRUCTURE IN MASSACHUSETTS

There are eight investor owned and four municipal gas distribution, utilities also known as local distribution companies ("LDCs"), operating in Massachusetts.[11] These companies own over 21,000 miles of gas main and 1 million services.[12] Almost one-third of the mains in Massachusetts are cast iron or unprotected steel, materials that are often referred to as "leak-prone" pipe.[13] These types of pipelines are referred to as "leak-prone" because according to EPA data and company-specific data, they tend to have a higher leakage rate. For example, in its recent regulations requiring greenhouse gas emissions reporting from the oil and gas industry, known as Subpart W, the EPA set forth the following emissions factors for distribution pipelines:

Material	Emissions Factor (scf/hour/mile)
Cast Iron	27.25
Unprotected Steel	12.58
Plastic	1.13
Protected Steel	0.35

See 40 C.F.R. Part 98, Subpart W, Revision to Petroleum and Natural Gas Systems. According to these figures, cast iron and unprotected steel result in far greater emissions than either protected steel or plastic pipe. As a result, distribution systems with large amounts of such leak-prone pipe are likely to experience equally large fugitive emissions. In Massachusetts, as of December 31, 2010, these leak-prone pipes accounted for almost 7,000 miles, over 30% of the entire distribution system:

Material	Miles
Cast Iron	3,990
Unprotected Steel	3,080
Total	7,070

The Massachusetts Department of Public Utilities developed regulations to ensure that no additional cast iron is used in the system and these same regulations required LDCs to replace or retire cast iron pipe under specified circumstances,[14] but investor-owned utilities face many competing demands for determining how to allocate capital expenditures, and these regulations do not extend to wholesale replacement of the aging cast iron pipelines on the system. Under current regulations, decisions about whether to repair or replace leaking pipelines are prioritized based on whether the particular leak or segment of pipeline poses an immediate risk to public safety and neither the Department nor the utilities take into account impacts on greenhouse gas emissions or other environmental factors. Both the federal and state regulations governing pipeline safety simply require that "hazardous" leaks be repaired "promptly."[15] As a result, leaks that persist for years may be left unrepaired so long as they remain "non-hazardous."

In addition, although it may be cost effective to repair or replace a pipeline, the rate of return may not be competitive with other types of capital investments the company could choose.[16] Although utilities are allowed to recover the costs of replacing pipeline, under traditional rate regulation that recovery does not occur until the filing of a rate case. This produces what utilities refer to as "regulatory lag," a period during which the company is responsible for carrying the costs of the capital investment, including any interest payments on loans. This can also create a disincentive for a utility to invest aggressively in replacement of pipes that may be leaking but are not necessarily considered hazardous.

In recognition of this disincentive, the Department has recently approved new mechanisms to facilitate capital spending on infrastructure replacement for three of the LDCs.[17] These mechanisms, known as targeted infrastructure replacement factors ("TIRFs") or more generically as capital trackers, allow LDCs to recover their capital expenditures for the replacement of leak prone pipelines on an annual basis rather than carrying the costs over until their next rate case.[18] Initially, these mechanisms appear to be having a positive impact on increasing the replacement of leak-prone pipeline; however, in their existing form, they do not require any consideration, measurement, or reporting of the estimated greenhouse gas reductions or reductions in lost and unaccounted for gas payments that can be attributed to replacement. Including this information is important not only to ensure that these co-benefits are maximized, but also to ensure that these replacement programs are actually achieving these benefits. Measurement and reporting of the impacts of replacement programs on fugitive emissions will also allow the Department to better integrate these co-benefits in future analyses of the cost-effectiveness of the programs.

Leaks that contribute to climate change may remain on the system indefinitely unless circumstances change such that the leak becomes considered hazardous.

As alluded to above, under existing laws and regulations, utilities, including LDCs, in Massachusetts are subject to "cost of service" rate regulation which is based on the principle that a utility "is entitled to charge rates which afford it the opportunity to meet its cost of service, including a fair and reasonable return on honestly and prudently invested capital."[19] This includes the utility's expenditures on capital projects such as replacing pipelines. LDCs may also recover the costs they expend on operations and maintenance such as identifying, classifying, repairing and monitoring leaks; however, unlike an investment in new pipeline, the company recovers only the expense and a reasonable rate of return without the added benefit of being able to add a capital addition into its rate base. This bias towards investing in capital expenditures rather than operating and maintenance expenses is known as the Averch-Johnson effect, and must be taken into account in crafting solutions.[20] Recoverable costs also include the cost of the commodity, in this case natural gas. The LDCs purchase natural gas for the system, and the cost is "passed through" to ratepayers in the form of a "cost-of-gas adjustment clause."[21] Ratepayers pay the same cost to the LDC that the LDC paid to the gas supplier—there is no mark-up; however, LDCs are also allowed to pass through the costs of any gas that is purchased but "lost" on the system between the transmission hub and the meter. This state of affairs stands in sharp contrast to the situation facing gas producers who are able to reap additional profits by selling any natural gas that they prevent from escaping from the well head or during processing, and it essentially removes any incentive to repair leaks unless the leak is considered hazardous.[22] As a result, leaks that contribute to climate change may remain on the system indefinitely unless circumstances change such that the leak becomes considered hazardous.

LDCs are allowed to pass on the costs of fugitive emissions to customers, at a rate of $38.8 million annually.

ASSESSING THE CLIMATE CHANGE IMPACTS FROM FUGITIVE EMISSIONS

Methane is an extremely potent greenhouse gas with a much shorter atmospheric lifespan than carbon dioxide. Assessing its impact on climate change and its relative importance depends upon establishing a proper global warming potential ("GWP"). The GWP value of 21 listed for methane is that published in the 1995 IPCC assessment report under a 100-year time horizon. Carbon dioxide has a lifetime of around 100 years in the atmosphere while that of CH4 is only about 12 years (IPCC 2007). The 100-year time horizon has become the standard for comparison across greenhouse gases, despite the fact that a 20-year horizon is arguably more appropriate for evaluating short-lived gases such as methane. Subsequent IPCC reports have published larger GWP values for methane. The third IPCC assessment (2001) reports a value of 23 over a 100-year time horizon (62 over 20 years) and the most recent IPCC assessment (2007) reports a value of 25 over a 100-year time horizon (72 over 20 years). Further, recent work by Shindell et al. (2009) and Kurtén et al. (2011) suggest that previously unaccounted for gas-aerosol interactions significantly increase the GWP of methane to 33 over a 100-year time horizon (79 to 105 over 20 years). While the GWP value of 21 for methane is used here because that is the GWP that has been adopted by Massachusetts and the EPA, it is important to note that subsequent research has determined that the value is actually significantly higher. Therefore, the impact of urban natural gas leaks on global warming reported in this document likely underestimates the magnitude of the true impact. Although we've used 21 as the GWP here, we recommend that the DEP, DPU, EPA and other agencies adopt the more recent IPCC figure of 25 or consider using the "technology warming potential" approach set forth by Alvarez.

Methane accounts for 10% of the total U.S. GHG inventory, and it has been rising steadily.[23] Fugitive emissions from the Oil & Gas industry make up 3.8% of the total methane emissions, and of that, almost 11%, or 72 billion cubic feet, come from the distribution system.[24] In Massachusetts, according to reports filed with the Department of Environmental Protection, fugitive emissions from distribution pipelines amounted to roughly 700,000 tons of CO2 equivalent (CO2e) for 2010.

Company	CH4 Metric Tons	GWP Factor	CO2e Metric Tons
Bay State/Columbia	7,263.005	21	152,523.105
Nstar	4,198.24	21	88,163.04
Colonial d/b/a NGrid	2,345.44	21	49,254.24
Boston Gas d/b/a NGrid	18,631.96	21	391,271.16
Berkshire	788.78	21	16,564.38
TOTAL	33,227.425	21	697,775.925

However, this number is dwarfed if estimates are based instead on the lost and unaccounted for gas reports filed by the LDCs to the DPU. The fugitive emissions reported under that methodology amount to almost 3.6 million tons of CO2e—over five times the emissions, and 4.2% of the Massachusetts total greenhouse gas inventory. [25]

Company	Lost Gas in MMcf (2010 SQ	CO2 Equivalent (metric tons)
Bay State/Columbia	803.9780	320,992.7940
Nstar	1,057.1080	422,056.9232
Colonial Gas d/b/a NGrid	1,268.9620	506,640.3034
Boston Gas d/b/a NGrid	6,006.6890	2,398,204.7830
Essex Gas d/b/a NGrid	(37.5160)	(14,978.4776)
Fitchburg (dekatherms)	(68.3480)	(27,288.3281)
Blackstone	0.6210	237.9378
Berkshire Gas Co.	(22.7980)	(9,102.2313)
New England Gas Co.	26.5990	10,619.8022
TOTAL		3,607,383.51

Under either scenario, this is a significant contributor to the total Massachusetts Greenhouse Gas Emissions inventory ranging from a low of 0.8% to a high of 4.2%. It is also important to consider these figures in the context of the mandate to reduce GHG emissions 25% below 1990 levels by 2020.[26] Looked at from that perspective, eliminating these fugitive emissions could help Massachusetts to achieve between 2.5% to 15% of the total reductions required by 2020. From a pure cost analysis, using an average of $4.30/Mcf, these losses cost ratepayers $38.8 million annually. Of course, it would be too simplistic to say that all lost and unaccounted for gas can be attributed to leaks, therefore the 3.6 million figure is not definitive.[27] Requiring companies to better account for the sources of the lost and unaccounted for gas would provide valuable data to guide policy-makers.

More work must be done to increase the accuracy of the accounting for fugitive emissions from distribution pipelines. The discrepancies between the data collected by the Massachusetts Department of Environmental Protection and the data from the Department of Public Utilities illustrate the lack of transparency and accuracy surrounding methane leaks from distribution pipelines. This problem is not unique to Massachusetts, but actually emanates from the flawed analysis developed jointly by EPA and the Gas Resources Institute in 1992. The emissions factors established by this study, known as the EPA/GRI study, have recently been called into question by the EPA itself.[28] According to a 2009 study, the leak rates established for cast iron pipelines may have been underestimated by no less than half. The original study relied upon a sample size of only 21 while a more recent study conducted in Brazil evaluated over 900. The results are represented below:

Study	Location	Year	Sample Size	Leak Rate (scf/mile-year)
EPA/GRI	North America	1992	21	428,123
Comgas	Brazil	2005 — present	912	803,548

Nonetheless, in the EPA's recent rulemaking requiring greenhouse gas reporting from oil and gas companies, known as Subpart W, the EPA continues to rely on this outdated, discredited methodology to calculate the fugitive emissions from pipelines.[29] Notably, the EPA did change the estimates for three existing sources including gas well liquids unloading, condensate storage tanks and centrifugal compressors and added two new sources that were not accounted for by the initial EPA/GRI study, but the EPA did not provide updates for distribution systems.[30] Natural gas companies understand the deficiencies of this methodology and seem willing to work with regulators to develop a more accurate tool. The Massachusetts Department of Environmental Protection should work with EPA and the local LDCs to use existing leak surveys from the companies to establish a better, Massachusetts-specific, leak rate to be used for determining more accurate estimates of emissions. Establishing credible, replicable methods for calculating emissions from natural gas infrastructure is critical. Without better data, it is difficult to assess the true impact of increased natural gas use, pinpoint the major sources of fugitive emissions, and evaluate whether policies are achieving their intended results.

POLICY OPTIONS:

Fortunately, there are a number of policy options that could be pursued to reduce greenhouse gas emissions from natural gas distribution pipelines cost effectively and expeditiously. The five policy options laid out below either build on existing mechanisms or recommend changes to incentive structures. The prime candidates include: (1) Establishing Leak Classification and Repair Timelines, (2) Limiting cost recovery for lost and unaccounted for gas, (3) Expanding Targeted Infrastructure Replacement Programs, (4) Changing Service Quality Standards, and (5) Enhancing Monitoring and Reporting Requirements.

LEAK REPAIR CLASSIFICATION AND TIMELINE REQUIREMENTS

Under the federal regulations governing pipeline safety, there is no standardized set of leak classifications, and repair is only required for "hazardous leaks."[31] As a result, in states that have not adopted their own set of leak classifications and repair timelines, utilities have great discretion in determining when and whether to repair a particular leak. Most utilities have adopted a standardized set of leak classifications, developed by the industry, which divides leaks into three categories. The most d in high consequence areas are generally considered Grade 2; and leaks that are in low consequence areas and not under pressure are classified as Grade 3. In virtually every state that has adopted leak classification and repair timelines, Grade 1 leaks require immediate action or repair. However, timelines for repair of Grade 2 and Grade 3 leaks vary widely, and regula-

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tions may require nothing more than re-evaluation of these leaks to ensure that they have not developed into Grade 1 leaks. This is a missed opportunity for states to exercise greater control over greenhouse gas emissions from pipelines.

Although legislation was proposed in the most recent Massachusetts legislative session that would have established a leak grading system and timelines for certain leak repairs, legislation is not necessary to advance this policy. The Department of Public Utilities has the authority to establish leak grading requirements and timelines for leak repairs under Massachusetts and federal law.[32] Massachusetts law provides the Department with the authority to "establish . . . such reasonable rules and regulations consistent with this chapter as may be necessary to carry out the administration thereof."[33] Massachusetts law also provides that natural gas pipelines "shall be subject to such reasonable rules and regulations as the department may prescribe or adopt pertaining to the construction and operation of such pipe lines for the purpose of insuring the safe operation thereof."[34] The federal safety regulations allow states to impose "additional or more stringent requirements" on owners and operators of intrastate pipelines, so long as they are compatible with the minimum federal standards.[35] As noted above, the Department has, in the past, established regulations that are more stringent than the federal standards to ensure pipeline safety. For example, the Department promulgated regulations governing the operation, maintenance, replacement and abandonment of cast iron pipelines.[36] Thus, it is clear that the Department could develop regulations intended to increase safety and reduce greenhouse gas emissions by establishing a uniform system of leak grading for the LDCs and a specified timeline for leak repair. Indeed, over thirteen states have developed regulations along these lines.[37]

Three northeastern states, Maine, New York[38] and New Hampshire[39], have already established leak classification and repair regulations that Massachusetts could look to for guidance. The regulations developed by Maine are the most likely to address the issue of expediting the repair of leaks that may not be considered hazardous, but are, nonetheless, contributing to greenhouse gas emissions because Maine requires repair of all grades of leaks. Maine's regulations define three separate grades of leaks:[40]

- Grade 1 is defined as a leak that represents an existing or probable hazard to persons or property and requires prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.

- Grade 2 means a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair or removal within six months or less of detection due to the probability of its future hazard.

- Grade 3 means a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

The Maine regulations require immediate action to repair a Grade 1 leak, and continuous monitoring until the repair is completed. Id. at § 6D.2.a. Grade 2 leaks must be repaired within 30 days of detection if they are classified as a "Priority 1" leak which is defined in the regulations. Id. at § 6D.3.c. If the leak is not a Priority 1 leak, it must be re-evaluated every 30 days until it is repaired. Id. at § 6D.3.d. Grade 3 leaks must be repaired within 24 months of detection unless they are scheduled for replacement under an existing replacement program; however, they must be re-evaluated every 180 days until the leak is cleared. Id. at § 6D4.b-c. It appears that this type of regulation may be having a positive impact in Maine. According to the Energy Information Administration, Maine has one of the lowest rates of lost and unaccounted for gas in the country with a rate of 0.4% for 2010.[41] There are two important features of the Maine regulations that stand out. First, it allows a company not to repair a grade 3 leak if it is part of a segment that is scheduled for replacement under an existing program. That means that neither the company nor ratepayers are saddled with the costs of repairing a leak that would already be dealt with through replacement of the existing pipeline. Second, the Maine regulations do not allow a utility to "downgrade" a leak. Id. at § 6D.8. This prevents a utility from remedying a Grade 1 or Grade 2 leak by venting the leaking gas into the atmosphere, which is a practice that reduces the possibility of explosion by relieving the pressure, but as a result produces greater greenhouse gas emissions. Further analysis would need to be done of each state that has leak classification and repair timelines to determine whether there is a consistent correlation between the requirements and lower levels of greenhouse gas emissions and unaccounted for gas, but it seems logical that a leak repair timeline coupled with replacement of leak-prone pipes on the system should greatly reduce fugitive emissions. Information about each state with an existing leak classification and repair timeline program is included in Appendix A.

LIMITING COST RECOVERY FOR LOST AND UNACCOUNTED FOR GAS

Lost and unaccounted for gas ("LAUF") has been an accepted cost of service since the early days of rate regulation in the United States.[42] The United States Supreme Court recognized, as early as 1934, that "There is no dispute that a certain loss [of gas] through these causes is unavoidable, no matter how carefully business is conducted."[43] The causes the Court referred to then are largely the same as those recognized in utility rate proceedings and other regulatory contexts today: leakage, condensation, expansion, or contraction, and the added factors of theft, meter inaccuracy, and venting during maintenance. However, the fact that there may always be some loss on the system should not be used as an excuse for failing to track and correct the causes of loss that can be addressed. Unfortunately, the fact that there is no distinction between cost recovery for gas that is lost through unavoidable means and gas loss that could have been avoided means that companies do not typically even attempt to quantify whether and how they might reduce their lost and unaccounted for gas volumes.

New York is one of the only states that has attempted to tackle this issue through adjustments to the way that companies are compensated for LAUF. The New York Public Service Commission actually establishes an allowed LAUF benchmark during an LDC's rate case and allows the LDC to recover an incentive for its shareholders if it achieves a lower LAUF than allowed, or a penalty that is returned to ratepayers if the company exceeds the allowed LAUF.[44] New York reported a statewide LAUF of 1.8% in 2010 as compared with Massachusetts which reported 2.8% within the same time period.[45] Still, it is very difficult to tie changes in LAUF to specific policies, because factors other than leaks, such as meter inaccuracies and weather may play such a large role in swings from year to year. The issue of meter inaccuracy may sound small, but under current Massachusetts regulations, meter inaccuracies could theoretically account for virtually all LAUF. That is, Massachusetts law provides that meters may vary up to two percent from the standard measure.[46] Therefore, if Massachusetts considers changes to the LAUF recovery mechanism, it may need to start by considering whether its current regulations regarding the standards for meter accuracy are consistent with the goal of reducing LAUF. The Department should open an investigation into establishing better reporting and recordkeeping requirements regarding LAUF and determining what changes to the cost recovery structure could reduce greenhouse has emissions.

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EXPANDING THE TARGETED INFRASTRUCTURE REPLACEMENT PROGRAMS

As explained above, the Massachusetts Department of Public Utilities has already approved targeted infrastructure replacement factors (TIRFs) for three of the LDCs to accelerate the replacement of leak-prone pipes, including both cast iron and unprotected steel. Mechanisms like these have been gaining traction throughout the country, in part because of the major safety concerns that were raised in the wake of high profile gas pipeline explosions in San Bruno, California and Allentown, Pennsylvania. After the San Bruno explosion, Secretary Ray LaHood of the United States Department of Transportation issued a "Call to Action" to improve the nation's pipeline safety.[47] The Department of Transportation, and its Pipeline and Hazardous Materials Safety Administration ("PHMSA") have recognized the unique risks posed by aging cast iron pipelines and services. Not only are they typically among the oldest infrastructure on the system, but they are often located in dense urban areas which makes replacement difficult and expensive. Massachusetts is one of the states with the highest amount of cast iron pipeline remaining in its system.[48] According to the National Association of Pipeline Safety Representatives, twenty-two of the thirty states with cast iron pipeline have initiated replacement programs, and PHMSA has issued an alert calling on owners of cast iron pipelines to conduct a comprehensive review of their system and replacement programs and accelerate repair, rehabilitation and replacement of high-risk pipelines.[49] The alert also requested that state agencies consider enhancements to replacement plans and programs.

However, none of the existing TIRFs explain the connection to infrastructure replacement and GHGs and the reduced costs of lost and unaccounted for gas. There is an opportunity to expand the reporting and planning requirements to include targeted reductions of GHGs and other costs. Integrating these co-benefits into the TIRFs is essential to properly evaluating the cost-effectiveness of such programs.

Capital trackers are not unique to investments in the replacement of infrastructure. They are often used to assist utilities in dealing with costs that are considered extraordinary, outside the utility's control, and substantial and recurring.[50] Other costs that are often subjected to capital trackers include post-retirement employee benefits, bad debt, remediation, and property taxes. Ratepayer advocates are wary of the use of capital trackers for a variety of reasons. In the case of capital trackers for the replacement of pipelines, ratepayer advocates tend to be most concerned about three issues: (1) the potential for replacing pipelines that are still serviceable or doing so at a cost that is exorbitant, (2) the possibility of the company using the investment to expand capacity rather than focusing on safety, and (3) the possibility that the plan will undergo less thorough review than it would have if submitted as part of a full rate case. All of these issues can be addressed by a carefully crafted capital tracker.

Three of the existing capital trackers in New England provide good models for addressing the issue of greenhouse gas emissions from natural gas distribution infrastructure.[51] The most comprehensive and well developed is the "Gas Infrastructure, Safety, and Reliability Plan" in Rhode Island. Below is a description of important features that can ensure that a TIRF meets the goals of enhancing safety and reliability while also reducing greenhouse gas emissions.

IDENTIFYING AND TARGETING THE SOURCES OF LEAKS AND WEAKNESSES

All three of the TIRFS referenced above limit cost recovery for capital expenditures to specific types of pipeline on the system determined to qualify as "leak-prone." The type of pipeline categorized as such may vary by distribution company, and in the case of National Grid, the TIRF includes cast iron and unprotected steel while Bay State Gas' current TIRF only includes unprotected steel. In establishing a TIRF, it is important that the Department have an opportunity to closely evaluate the current conditions on a utility's system to ensure that the TIRF is geared towards replacing the materials on the specific system that are contributing to leaks. In some cases, it may be important to include infrastructure associated with the leak-prone pipe such as meters, regulators, risers, or other materials if the company has demonstrated that these are significant sources of leaks. TIRFs can also be limited to the replacement

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of existing pipeline and explicitly prohibit the coverage of costs for expanding service. This is a common ratepayer advocate concern that was directly addressed by the Kansas and Missouri statutes described in Appendix B.

"O&M Offsets"

The TIRF should also provide for "O&M offsets" to be included in the calculations. An O&M offset refers to the reduction in operations and maintenance expenses due to leak repair and monitoring that a utility would have experienced had it not replaced the segment of pipeline through the TIRF. For example, in the Massachusetts National Grid TIRF, for each mile of pipeline that is repaired, National Grid subtracts an O&M offset of $4,557 from its TIRF recovery. This O&M offset is based on a calculation estimating the costs the company would have incurred in leak repairs on leak-prone pipelines but for the replacement of the pipe. In the National Grid case, this was based on the weighted average test year cost of leak repairs on non-cathodically protected steel and small diameter cast/wrought iron mains which were the types of materials covered by the TIRF. This type of offset ensures that ratepayers receive the benefit of the reduced operations and maintenance costs that are being enjoyed by the company as a result of the capital expenditure. Establishing a company-specific O&M offset also helps to highlight the direct benefits of the replacement program and evaluate the cost-effectiveness of the TIRF.

Pre-Approval of a Plan with Specific Targets and Benchmarks

Rhode Island provides the best example of this in New England. The Company is required to meet with the Office of Consumer Advocate to develop a plan that is then presented to the Public Utility Commission. This ensures that ratepayer concerns are being addressed up front in the development of the plan. In addition, the company is required to follow a risk-based approach with a clear 8-step process for prioritization of replacement. These plans also include commitments to replace a specific number of miles of each type of pipe, and in the case of the Rhode Island program, the company is required to provide quarterly reports on its progress. Having a pre-approved plan in place with set targets reduces administrative burden for the regulator because s/he can compare the progress to the targets and more easily determine where issues that need review have arisen.

Enhanced Reporting and Record-Keeping

Of the twenty-two replacement programs currently in place throughout the country, none of them require the company to report on the reductions in greenhouse gas emissions or LAUF. If TIRFs are going to play a role in reducing greenhouse gas emissions, it is vital that companies be willing to measure their performance. Not all public utility commissions will have the authority, as Massachusetts does, to consider greenhouse gas emissions in their decisions. However, where that is the case, a commission could use LAUF reductions as a proxy (keeping in mind the difficulties with accurately measuring LAUF). A TIRF should require companies to provide reports on both the estimated reductions in greenhouse gas emissions and LAUF that can be attributed to actions under the TIRF program and develop enhanced programs for evaluating the quantity of gas escaping through leaks and other sources so that the companies may better address the issue of LAUF. Distribution companies have recently been subjected to a new "Direct Inspection and Maintenance Program" under federal law which requires them to conduct thorough risk assessments of their systems.[52] The information developed through these programs may prove useful in better quantifying the amount of gas leaking from the system through pipelines and other infrastructure, and the Department should work with LDCs to ensure that these programs are leveraged to address greenhouse gas emissions.

TIRFS provide a promising mechanism for reducing greenhouse gas emissions on the distribution system, but they must be expanded to include provisions that require measurement and reporting on greenhouse gas emissions if they are to be effective for that purpose. Although the capital expenditures for replacing pipelines may result in bill increases, they should be offset to some extent by the reduced operating and maintenance expenses for repairing leaks, the reduction in LAUF charges, and reduced greenhouse gas emissions.

As the New England electric grid becomes more reliant on natural gas, reducing the losses on the distribution system can play a role in enhancing reliability of the electric system.

INCORPORATING LEAK REDUCTION INTO SERVICE QUALITY STANDARDS

Service quality standards may also provide a mechanism for reducing fugitive emissions. Each year, the Department receives service quality reports from every LDC detailing the company's response time to odor calls, service appointments kept, lost time due to emergencies, and other areas of performance. The Department could consider including a standard for LAUF and/or greenhouse gas emissions. This would be an extremely straightforward way of addressing the issue, and could be done through opening a docket to amend the current service quality standards.

ENHANCED MONITORING AND REPORTING

The current uncertainty regarding the actual amount of fugitive emissions and LAUF presents serious obstacles to determining the best policy options for reducing these losses from the system. This problem is not confined to Massachusetts nor to the distribution sector, but persists throughout the United States gas industry from wellhead to customer meter. Scholars have raised serious concerns about the impacts of these fugitive emissions on the ability of natural gas to provide a less carbon-intensive alternative to coal, even over the short-term. The gas industry must be willing to work with regulators and stakeholders to remedy the current shortcomings in the ability to measure and quantify fugitive emissions. Massachusetts should call upon the EPA to convene a series of stakeholder meetings and workshops to develop new, more accurate tools for assessing fugitive emissions from the natural gas sector so that we can move forward with policies that effectively reduce and eliminate these emissions.

CONCLUSION

Natural gas use for the generation of electricity has seen an unprecedented rise over the last few years, and this trend appears likely to continue. As the New England electric grid becomes more reliant on natural gas, reducing the losses on the distribution system should play an important role in enhancing reliability of the electric system and avoiding unnecessary expansion of natural gas infrastructure. Scientific and industry studies have confirmed that the current level of fugitive emissions from the natural gas industry is high, but difficult to quantify accurately. Although Massachusetts has no direct control over natural gas production, processing, or transmission, it may regulate the distribution of natural gas in a variety of ways. Indeed, meeting the Commonwealth's mandate to reduce greenhouse gas emissions by 25% below 1990 levels by 2020 and 80% below 1990 levels by 2050 requires the Commonwealth to address this substantial source. In addition, reducing fugitive emissions from the distribution system will provide direct benefits to ratepayers through the reduction of costs for LAUF. The policy options that could provide the most immediate benefits include establishing leak classifications and repair timelines and expanding TIRF programs to include enhanced reporting and measurement of the impacts on greenhouse gas emissions and LAUF reductions. However, ensuring that these programs are successful requires more accurate measurement and evaluation of the sources of these fugitive emissions, and Massachusetts should press industry and the federal government to direct resources to address this issue in a transparent and expeditious manner. Every day, thousands of methane leaks are actively releasing one of the most potent greenhouse gas emissions into the air in Massachusetts. Under our current regulations, we do not have an accurate accounting of these emissions, ratepayers cannot easily determine how much of their bill is going towards LAUF, and companies have no incentive to repair leaks unless they pose an immediate hazard. Massachusetts can and should take swift, direct action to change this state of affairs and bring fugitive emissions from distribution pipelines under control.

How much GAS IS LOST en route to your home?

As little as

700,000

and as much as

3.6 million

Tons of CO2e are lost or unaccounted for through old or leaky pipes and other aging equipment.

that's

4% of MA total GHG emissions. = $38.8 million a year

a cost that is passed onto the ratepayer.

or enough for

18,000 homes per year

= 100 houses

MA's efficiency ambitions are going up into thin air.

A high percentage of MA's pipes are old or leak-prone. In 2010, MA Statewide Energy Efficiency Plans saved a lot of gas — but we are losing more from leaks than we're gaining from efficiency.

We're LOSING more than we're SAVING!

1,097
millions of cubic feet
SAVED
through efficiency

1,725
millions of cubic feet
LOST
through leaks

For more, including a free whitepaper, visit:

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ENDNOTES

[1] Ramon Alvarez, et al., *Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure*, PNAS: doi: 10.1073/pnas.1202407109.

[2] "Fugitive Emissions" include methane that escapes to the atmosphere from a variety of sources including intentional venting during production and processing and unintentionally as a result of leaking pipes, regulators, compressors and other infrastructure. Under the Global Warming Solutions Act, Massachusetts is required to reduce greenhouse gas emissions economy-wide by 25% below 1990 levels by 2020 and by 80% below 1990 levels by 2050. *See* M.G.L. c. 21N, §§ 3,4.

[3] Neena Satija, *Thousands of Gas Leaks in Boston Area*, Boston Globe, August 17, 2011 available at http://articles.boston.com/2011-08-17/news/29897396_1_gas-leaks-natural-gas-gas-companies.

[4] The Boston University Study's findings regarding the number of leaks in Boston are in line with reporting to the Department of Transportation and the Massachusetts Department of Public Utilities. *See* D.P.U. 12-38, Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Review and Approval of its Targeted Infrastructure Replacement Factor for 2011, NG-WFF-6 at 3 (Reporting 4,285 leaks on leak-prone pipelines in 2011), available at http://www.env.state.ma.us/dpu/docs/gas/12-38/5112ngcmpex2.pdf; National Grid reported 3,772 leaks on its Boston Gas Company mains to the Department of Transportation. *See* Gas Distribution Annual Form 2011, PHMSA, Form F 7100.1-1.

[5] "Lost and Unaccounted for Natural Gas" is a term used by industry and the federal government to refer to annual mismatches between measured natural gas inputs to the transmission and distribution system, and the sum of end-user consumption of natural gas. American Gas Association, Natural Gas Rate Round-up, "Lost and Unaccounted for Gas Cost Recovery Mechanisms," available at http://bit.ly/rgbIrK. These mismatches vary from year to year, but were nearly 13 billion cubic feet of natural gas in 2008 and 2009, which correspond to 6-8% of Massachusetts' total greenhouse gas inventory, Energy Information Administration (EIA), Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition."

[6] Tom Zeller, Jr., *Methane Losses Stir Debate on Natural Gas*, N.Y. Times, April 12, 2011; Jim Witkin, *Replacing Coal with Gas No Panacea*, N.Y. Times September 14, 2011; Robert W. Howarth, et al., *Venting and Leaking of Methane from Shale Gas Development: Response to Cathles, et al.*, Climatic Change: DOI 10.1007/s10584-012-0401-0; Ramon Alvarez, et al., *C*, PNAS: doi: 10.1073/pnas.1202407109.

[7] More information about the Global Methane Initiative. *See* Global Methane Initiative, "About the Initiative," available at http://www.globalmethane.org/about/index.aspx.

[8] More information on the EPA Natural Gas STAR Program which provides support to the Global Methane Initiative is available at http://www.epa.gov/gasstar/basic-information/index.html.

[9] Concentric Energy Advisors, New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corporation, 3, 26 (May 2012).

[10] Connecticut Department of Energy and Environmental Protection, Draft Comprehensive Energy Plan (Oct. 22, 2012)

[11] These include National Grid (Boston Gas and Colonial Gas), NStar Gas, Columbia Gas, Fitchburg Gas & Electric, New England Gas Company, Blackstone, Berkshire Gas, City of Holyoke Gas & Electric Department, Middleborough Gas and Electric Department, Wakefield Municipal Gas and Light Department, and Westfield Municipal Gas and Electric Light Department.

[12] *See* Letter from Christopher Bourne, Director, Pipeline Engineering and Safety Division, Massachusetts Department of Public Utilities to Cynthia Quarterman, Administrator, Pipeline and Hazardous Materials Safety Administration (April 12, 2011) available at http://opsweb.phmsa.dot.gov/pipelineforum/docs/letters/DPU%20Response%20Letter%20PHMSA%20Administrator%20-%204-12-11.pdf. A gas "main" is a pipeline that "serves as a common source of supply for more than one service line." *See* 49 C.F.R. 192.3. A "service" is a distribution pipeline that "transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold." *Id*.

[13] *Id*.

[14] *See* 220 C.M.R. 113.00 et seq.

[15] *See* 49 C.F.R. § 192.703(c) ("Hazardous leaks must be repaired promptly."); 220 C.M.R. 101.06(21)(e) ("All disclosed conditions of a nature hazardous to persons or property shall be promptly made safe and permanent repairs instituted.").

[16] The same phenomenon occurs at other stages of natural gas production and transport. *See* NRDC, Susan Harvey, "Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste," 9 (March 2012) ("The American Petroleum Institute (API) explains that in order to maximize profit and provide shareholders with the highest possible return on investment, the O&G industry operates with a strict ranking of capital projects for maximum yield.").

[17] The three companies with approved targeted infrastructure replacement factors are: National Grid, D.P.U. 10-55; Bay State Gas d/b/a Columbia Gas, D.P.U. 9-30; and New England Gas Company, D.P.U. 10-114.

[18] These mechanisms are in effect for National Grid, Columbia Gas and New England Gas. They will be described in greater detail below.

[19] S. Union Co. v. Dep't of Pub. Utils., 458 Mass. 812, 824 (2011) (citing Boston Gas Co. v. Dep't of Pub. Utils., 367 Mass. 92, 97 (1974)).

[20] For a further explanation of the Averch-Johnson effect, *see* Boyes, W.J. (1976), *An Empirical Examination of the Averch-Johnson Effect*. Economic Inquiry, 14: 25–35. doi: 10.1111/j.1465-7295.1976.tb00374.x.

[21] The Cost of Gas Adjustment clause has been codified in Massachusetts at 220 C.M.R. 6.00.

[22] *See*, *supra, Leaking Profits* at 18.

[23] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2010), ES-4, April 15, 2012 (Indicating that methane emissions from the Natural Gas system rose in the U.S. from 189.6 million metric tons of CO2e in 1990 to 215.4 million metric tons of CO2e in 2010.).

[24] U.S. EPA, Natural Gas Star Program, *Basic Information*, available at http://www.epa.gov/gasstar/basic-information/index.html#overview1.

[25] According to the most recent Massachusetts Department of Environmental Protection update, GHG emissions in Massachusetts were 84.1 million metric tons in 2009. DEP, Final 2006-2008 Massachusetts Greenhouse Gas Emissions Inventory (July 2012) available at http://www.mass.gov/dep/air/climate/gwsa_docs.htm#implement.

[26] This calculation is based on an estimated need to reduce emissions by 23.43 million tons of CO2e by 2020 to achieve a 25% reduction.

[27] Lost and unaccounted for gas encompasses a variety of sources ranging from theft, meter inaccuracies, purging and venting during maintenance activities, and other causes. For examples, *see* New York Department of Public Service, Staff White Paper on Lost and Unaccounted for (LAUF) Gas, 16-21, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0413ECDD-C194-46DE-8B04-AFDB3FBBE404%7D.

[28] Carey Bylin, Luigi Cassab, Adilson Cazarini, Danilo Ori, Don Robinson, and Doug Sechler, "New Measurement Data Has Implications for Quantifying Natural Gas Losses from Cast Iron Distribution Mains," Pipeline & Gas Journal (September 2009).

[29] *See* 40 C.F.R. Part 98, Subpart W, Revision to Petroleum and Natural Gas Systems. However, notably, the EPA did change the estimates for three existing sources including gas well liquids unloading, condensate storage tanks and centrifugal compressors and added two new sources that were not accounted for by the EPA/GRI study, unconventional gas well completions and unconventional gas well workovers. See Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document, Appendix B. available at http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf.

[30] See Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document, Appendix B, available at http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf.

[31] *See* 49 C.F.R. 192.703.

[32] M.G.L. c. 164, § 76C; 49 U.S.C. § 60104 (2002).

[33] M.G.L. c. 164, § 76C.

[34] M.G.L. c. 164, § 75E.

[35] In order to impose such requirements, Massachusetts would need to file with the federal Department of Transportation a state pipeline safety program certification meeting the requirements of 49 U.S.C. § 60105. 49 U.S.C. § 60104(c).

[36] 220 C.M.R. 113.00 et seq.

[37] *See* National Association of Pipeline Safety Representatives, National Association of Regulatory Utility Commissioners, Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations, (1st Edition, 9/30/2011).

[38] N.Y. Comp. Codes R. & Regs. tit. 16 § 255.811.

[39] N.H. Code Admin. R. Ann. Puc 508.05(l).

[40] See 65-407 ME. Code R. Ch. 420 § 6D (2011).

[41] Energy Information Administration, *Natural Gas Annual 2010*, Appendix Table-A1 (2011) available at http://www.eia.gov/naturalgas/annual/pdf/table_a01.pdf.

[42] *See West Ohio Gas Co. v. Pub. Util. Com'n of Ohio*, 294 U.S. 63, 67, 55 S.Ct. 316, 319 (1935) citing Consol. Gas Co. v. Newton, 267 F. 231, 244 (S.D.N.Y. 1920) and Brooklyn Union Gas Co. v. Prendergast, 7 F.2d 628, 652, 671 (E.D.N.Y. 1926).

[43] *West Ohio Gas Co. v. Pub. Util. Com'n of Ohio*, 294 U.S. 63, 67, 55 S.Ct. 316, 319 (1935).

[44] *See In the Matter of the Filing of Annual Reconciliations of Gas Expenses and Gas Cost Recoveries, filed in C 21656*, Case 04-G-1278, at 9 (N.Y. P.S.C. 2005).

[45] EIA, Natural Gas Annual 2010, Table A1

[46] M.G.L. c. 164, § 103 (A meter shall not be correct if it varies more than two per cent from the standard measure.).

[47] *See* US Department of Transportation, "U.S Transportation Secretary Ray LaHood Announces Pipeline Safety Action Plan," available at: http://www.dot.gov/affairs/2011/dot4111.html. (April 2011).

[48] According to the PHMSA, at the end of 2009, fifty percent of the cast iron mileage in the country was located in four states: New Jersey, New York, Massachusetts and Pennsylvania. *See* PHMSA, "Cast Iron Pipeline R&D Projects," available at http://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline.

[49] *See* PHMSA Advisory Bulletin, 77 Fed. Reg. 17119 (March 23, 2012) available at https://www.federalregister.gov/articles/2012/03/23/2012-7080/pipeline-safety-cast-iron-pipe-supplementary-advisory-bulletin.

[50] *See* Ken Costello, *How Should Regulators View Cost Trackers*, The Electricity Journal, 22:10 (2009).

[51] National Grid in Massachusetts, D.P.U. 10-55 (2009); Bay State Gas in Massachusetts, D.P.U. 09-30 (2009); and National Grid's ISR plan filed annually in Rhode Island pursuant to R.I.G.L. § 39-1-27.7.1.

[52] The PHMSA finalized the rules for the Direct Inspection and Maintenance Program on December 4, 2009. *See* 74 Fed. Reg. 63906 (2009). Distribution

Appendix A – States with Leak Classification and Repair Timelines

The table below provides a more detailed description of how each of the states that has created a classification system grades leaks.

State	Law/Docket Nmber	Scope	Grading	Repair Timeline	Reporting	Other
Arkansas	Arkansas Gas Pipeline Code 192.723(e)	All	Class 1 (existing/ probable hazard), 2 (non-hazard but could become so), 3 (non-hazardand to remain so)	1 (immediate), 2 (ASAP, <5 months), 3 (as time and $ permits)	Every leak detected or identified must be recorded. Record must include date leak discovered, location, classification, cause of leak and initials of person making repair or maintaining records.	
Florida	Fla. Admin. Code Ann. r. 25-12.040 (2009)	All	Grade 1 (existing/ probable hazard), 2 (non-hazard but potential hazard), 3 (non-hazard and to remain so)	1 (immediate), 2 (<90 days), 3 (<90 days)	FAC 25-12.062 records of gas leaks must include address of suspected leak, date/time of reporting, description, date and time personnel dispatched, date and time personnel arrived, date and time condition made safe, location of leak found, cause	
Georgia	Ga. Comp. R. & Regs. 515-9-1.05 (1994)	All	Grade 1 (existing/ probable hazard), 2 (non-hazard but potential hazard), 3 (non-hazard and to remain so)	1 (immediate), 2 (<15 months), 3 (reevaluated during next survey or <15 months, whichever is first until repaired)	O.C.G.A. § 515-9-1-.06 operator must give telephonic notice ASAP or <2 hours, to Pipeline Safety Staff IF 1.Death or hospitalization 2. Property damage or cost of gas lost or both exceeding $5000 3. Emergency shutdown is required OR 4. If evacuation or road blocking is necessary Written report must be submitted <30 days to Pipeline Safety Office	
Kansas	Kan. Admin. Regs. § 82-11-4(bb) (2009) (49 CFR § 192.703)	All	Class 1 (existing/ probable hazard), 2 (non-hazard but potential hazard), 3 (non-hazard and to remain so)	1 (immediate if hazardous, when no longer hazardous <5 days), 2 (<6 months and monitored weekly under adverse soil conditions), 3 (rechecked every 6 months, repaired <30 months)	Operator must inspect/ classify all reports of gas leaks within 2 hours Record of each survey/inspection of leak must be kept for 5 years or until next survey/inspection is completed whichever is longer Date, location, description of each repair must be retained for 5 years (§ 192.709)	

Appendix A — continued — States with Leak Classification and Repair Timelines

State	Law/Docket Nmber	Scope	Grading	Repair Timeline	Reporting	Other
Maine	65-407 ME. Code R. Ch. 420 § 6D (2011)	All mains (annually), cast iron main lines (every 30 days b/w Dec-Apr 30), bldgs of public assembly (annually)	Grade 1 (immediate hazard), 2 (nonhazard but potential hazard), 3 (nonhazard and to remain so)	1 (immediate), 2 (if priority 1, <30 days, re-eval'ed every 30 days until repaired), 3 (re-eval'ed every 180 days until repaired, repair within 24 months)	Utility operator must record each gas leak report. Log must include incoming date, time, address, work order number, dispatcher name, technician name, time assigned to technician, time accepted by technician, time en route, time arrived on site, total travel time, total response time, time condition was made safe, response time classification (Ch. 420 § 7E) Utility must report to the Commission the amount of time from initial notice until leaks were made safe for each report of gas leak received by utility. (Ch. 420 § 7E(5)) Must submit monthly reports of leak and gas odor calls to which it responded. (Ch. 420 § 7G)	
Missouri	Mo. Code Regs. Ann. tit. 4, § 240-40.030 (2008)	All pipelines – not fuel lines	Class 1 (immediate hazard), 2 (not immediate hazard,), 3 (non-hazard), 4 (confined/ localized non-hazard)	1 (immediate. If reclassified as Class 2 then <15 days. If not repaired in <5 days, may need to be reported as a safety-related condition), 2 (rechecked every 15 days until repaired. If not reclassified, then repair within 45 days unless definitely scheduled for repair within a year but recheck every 15 days), 3 (<5 years, rechecked twice a year, not to exceed 6.5 months), 4 (no action)	Rule is similar to Minimum Federal Safety Standards in 49 CFR part 191. If a leak constitutes an emergency, then a safety-related condition report must be filed <5 business days but not later than 10 business days with Office of Pipeline Safety at PHMSA and designated commission personnel. Report must include operator name and address, date, name/title/ phone number of person submitted report, date of incident, location of incident, description, corrective action	Bare steel service line leaks, entire service line must be repaired

Appendix A — continued — States with Leak Classification and Repair Timelines

State	Law/Docket Nmber	Scope	Grading	Repair Timeline	Reporting	Other
New Hampshire	Puc 508.04	All	Class I (existing/ probable hazard), II (non-hazard but probable future hazard), III (non-hazard and to remain so)	I (immediate repair <24 hours or continuous action until no longer a hazard), II (repair <6 months or before end of calendar year), III (no stated repair timeline)	Utility must submit to commission a monthly leak report, description of status of any leak in system classified by type of leak. status of leaks should be described as of the beginning of each month, those reported during the month, those repaired during month, those reported and awaiting repair at end of month (Puc 509.15). If leak results in death/ personal injury requiring hospitalization or damage of $5000+, then utility must notify safety division of commission by phone (Puc 504.05)	
New Mexico	18.60.2.12 NMAC	All	Grade I/C (immediate hazard), II/B (potential hazard), III/A (non-hazard, no potential to become hazard)	I/C (immediate), II/B (reasonable time period), III/A (no stated repair timeline)	Reporting threshold in New Mexico is $5000 instead of the $50,000 established in 49 CFR 191.3 but otherwise similar to reporting requirements in 49 CFR Part 191.	
New York	N.Y. Comp. Codes R. & Regs. tit. 16 § 255.811	All	Type 1 (potential hazard to public/ buildings), 2A (not immediate hazard), 2 (not immediate hazard), 3 (not immediate hazard and to remain so)	Type 1 (immediate action until no longer hazardous), 2A (repaired <6 months, rechecked every 2 wks until repaired), 2 (repaired <1 year, rechecked every 2 months), 3 (rechecked annually)	If injury/death or damage to property or news media coverage could be involved, operator must report via telephone to the gas emergency notification system. Within 30 days, written report must be submitted setting forth chronology of events (Part 255.801)	Any sustained reading of four percent or less gas-in-air outside the curbline or shoulder of the road can be considered a nonreportable reading except where found in manholes, vaults, or catch basins (§ 255.821)
Ohio	Ohio Admin. Code 4901:1-16-04	All	Grade 1(existing or probable hazard, 2 (nonhazard but requires repair), 3 (nonhazard and to remain so)	1 (immediate repair or continuous action until hazard is removed), 2 (scheduled repair based on severity and/or location of leak <15 months unless pipeline is replaced <24 months), 3 (re-check every 15 months until repaired)	Reporting requirements consistent with regulations in 49 C.F.R. 40, 49 C.F.R. 191, 49 C.F.R. 192, and 49 C.F.R. 199	

Appendix A — continued — States with Leak Classification and Repair Timelines

State	Law/Docket Nmber	Scope	Grading	Repair Timeline	Reporting	Other
South Carolina	S.C. Code Ann. Regs. § 103-493	All	Grade 1 (existing or probable hazard), 2 (nonhazard but probable future hazard), 3 (nonhazard and to remain so)	1 (immediate repair or continuous action), 2 (requires scheduled repair), 3 (no stated repair timeline)		
Tennessee	Tenn. Comp. R. & Regs. 1220-4-5-.44 (2006)	All	Grade 1 (potential hazard to public or bldg, 2 (not immediate hazard), 3 (not Grade 1 or 2 leak)	1 (immediate and continuous action until corrected), 2 (scheduled for immediate repair within 12 months or rechecked during annual survey), 3 (rechecked during next survey)		
Texas	16 Tex. Admin. Code § 8.207 (2008)	Natural gas only	Grade 1 (existing or probable hazard), 2 (non-hazard but probable future hazard), 3 (non-hazard and to remain so)	1 (immediate action to eliminate hazard), 2 (re-evaluate every 30 days until repaired, depends on severity), 3 (repair <36 months, recheck during next survey or within 15 months)	PS-95 Semi-Annual Leak Report filed by July 15 and January 15 of ea. calendar year. Each operator must submit to the Division a list of all leaks repaired, all leaks identified, and number of unrepaired leaks remaining categorized by leak grade. 16 Tex. Admin. Code § 8.210(e) (2008)	Table for leak classification and repair deadlines PS-95 Semi-Annual Leak Report E-Filing Reqs

Appendix B – Replacement Programs

State/Company	Authority	Title	Scope	Notes
ARKANSAS				
CenterPoint	Docket No. 05-124-U Docket No. 12-045-TF Docket No. 00-353-U	Main Replacement Program Rider ("MRP Rider")	• Requires replacement of all Cast Iron Mains, Bare Steel Mains, and associated services by Dec. 31, 2027 • Required CenterPoint to spend a minimum of $8 million in 2006 and minimum of $12 million in 2007, 2008 on removal of old mains and services • Does not allow recovery for removal of retired main	• The program does provide for offsets for avoided leak repair costs • Based in part on settlement of alleged safety violations
CONNECTICUT				
Connecticut Natural Gas	Docket No. 08-12-06	Replacement and Reliability Programs	• Originally began in 1993, Docket Nos. 93 02 04, 95 02 07 • Establishes spending requirements • Includes cast iron and unprotected steel mains and services and some meter relocation	• Not a capital tracker

CONNECTICUT	Authority	Title	Scope	Notes
Yankee Gas	Docket No. 10-12-02		• 446 miles of cast iron and 90 miles of bare steel • Spending requirement of $40 million annually • Explicitly linked to DIMP regulations	• Not a capital tracker
GEORGIA				
Atlanta Gas	Docket No. 8516-U	Pipeline Replacement Program	• Replace 2600 miles of cast iron and bare still in 15 years • Allows annual cost recovery filing	• Based in part on settlement of alleged safety violations • Penalties for failure to replace a specified mileage each year
Atmos	Docket No. 12509-U	Pipeline Replacement Surcharge	• Proposal to replace 184 miles of Cast Iron and 46 miles of bare steel in 20 year period	• Offsets for reduced O&M and for reduction in depreciation expense for retired assets • Exempts senior citizens and low income customers
INDIANA				
Statewide	170 IAC 5-3-4(e)	Required reporting for replacement programs	• Enhanced reporting requirements for capital projects including cast iron and bare steel replacement	
Vectren	IURC 43298	Vectren North	• Limited to bare steel and cast iron in specific areas • $20 million annual limit • Limited to replacement of existing facilities with new materials	• Tracking mechanism that allows deferral and allowance for funds used during construction for 4 years from date of replacement • No offset
Vectren	IURC 43112	Vectren South	• Limited to bare steel and cast iron • $3 million limit	• Tracking mechanism that allows for deferral and allowance for funds used during construction for 3 years from date of replace-ment • No offset
KANSAS				
Statewide	Kan. Stat. Ann. 66-2202 through 66-2204 (2006)	Gas System Reliability Surcharge	• Extends to mains, services, valves, regulators, vaults, and inserts • Only replacement of existing infrastructure not lines to serve new customers	
Statewide	Kans. Admin. Reg. § 82-11-4-(ee)(6), 82-11-4(i), 82-11-4(k)	Regulations requiring replacement of unprotected steel and cast iron in certain circumstances	• Cast Iron leaks from body of pipe joint must be subjected to lab analysis to determine percentage of graphitization and replaced within 120 days if graphitization above a specified value; • Replacement of all CI < 3in diameter by 2013	
City of Lyon	Docket No. 06-LYOP-641-SHO	Replacement	• Stipulated order for violations requiring City of Lyon to replace entire distribution system	

KANSAS	Authority	Title	Scope	Notes
Atmos	Docket No. 10-ATMG-133-TAR	Replacement	• Surcharge consistent with statute	
Black Hills	Docket No. 09-BHCG-886-TAR	Replacement	• Surcharge consistent with statute	
Kansas Gas	Docket No. 07-AQLL-431-RTS	Replacement	• Surcharge consistent with statute	
MAINE				
Northern Utilities d/b/a Unitil	PUC Docket # 2008-00151	Replacement	• Cast iron, wrought iron and non-cathodically protected bare steel and service renewals and tie-overs, meter replacements, valve replacements and regulator station retirements • Replacement by October 2024 or 2027 at the latest • Base rate surcharge	• Motivated in part by multiple incidents on cast iron including 2004 explosion • Settlement with the Office of the Public Advocate • Allows recovery for plastic inserts • Estimated bill impacts of 2% • Estimated cost of $64 million • Includes offset
MASSACHUSETTS				
National Grid	10-55	Targeted Infrastructure Recovery Factor ("TIRF")	• Cast iron less than 8 in. in diameter and unprotected steel and associated services and meters • 10 year term • Cost recovery cap of 1% of total revenues with option for deferral	• O&M Offsets of $4,557 per mile for Boston-Essex Gas; $2,518 per mile for Colonial Gas • Utility proposed target for reduced leak rate
Bay State Gas	09-30	Targeted Infrastructure Recovery Factor ("TIRF")	• Bare and unprotected coated steel mains • 10-15 year term • Cost recovery cap of 1% of total revenues with option for deferral	• O&M Offset of $2,077 per mile
New England Gas	10-114	Targeted Infrastructure Recovery Factor ("TIRF")	• Cast iron, wrought iron, unprotected steel and bare steel mains and services and associated infrastructure • Cost recovery cap of 1% of total revenues with option for deferral	• O&M Offset of $3,959 per mile
MICHIGAN				
Michigan Consolidated	U-15985 U-16407	Main Renewal Program	• 10 year program with annual average cost of $1.14 per customer in year 1 up to $23.27 per customer in year 10. • Cast iron, wrought iron and unprotected steel mains and where appropriate service lines and associated meters • Cost recovery through rate case NOT tracker	• Provides for Commission review, analysis of customer affordability, determination of appropriate size of the program, review of an appropriate method of financing and segregating the program from other capital spending, and a proposal for recovery of the capital costs.
SEMCO	U-16169	Main Replacement Rider	• Limited to cast iron and unprotected steel service lines and mains	• Includes offset

MINNESOTA	Authority	Title	Scope	Notes
Statewide	Minn. Stat. § 216B.1637	Recovery of certain greenhouse gas infrastructure costs	• Allows for recovery of replacement costs of cast iron distribution and service lines and breakers that may contain sulfur hexafluoride • Timely recovery through rate adjustment mechanism IF costs are not excessive	
Xcel Energy	Docket No. E,G002/M-09-201	State Energy Policy Rider Adjustment (“SEP Rider”)	• 20.5 miles of cast iron • $12 million over 3 years	
MISSOURI				
Statewide	Mo. Code Regs. Ann.. tit. 4, § 240-40.030(15)	Replacement Programs	• Unprotected steel service lines and yard lines, cast iron transmission lines, feeder lines or mains, unprotected steel transmission lines, feeder lines or mains • Required utilities to present plans for replacement by 1990	
Statewide	Mo. Rev. Stat. §§ 393.1009-393.1015	Infrastructure System Replacement Surcharge (“ISRS”)	• Limited to replacement of existing pipelines • Includes main relining, inserts, and other life extension projects • Applies to any “worn out” or “deteriorated” mains, valves, service lines, regulators, vaults and associated pipeline components	• Utility must file a rate case every three years to be eligible • The ISRS cannot be greater than 10% of total base
Ameren	GT-2009-0413	ISRS	• Consistent with ISRS statute; some ISRS has been transferred to base rates	
Atmos Energy	GO-2009-0046	ISRS	• Consistent with ISRS statute	
Laclede Gas	GR-2007-0208	ISRS	• Consistent with ISRS statute; some ISRS has been transferred to base rates	
Missouri Gas Energy	GR-2009-0355	ISRS	• Consistent with ISRS statute; some ISRS has been transferred to base rates	
NEVADA				
Southwest Gas Corporation	Docket 11-03029	Strip Reliability Plan	• Creation of deferred regulatory asset • Replacement of old PVC pipe on the Las Vegas strip	
NEW HAMPSHIRE				
National Grid	Order #24777 DG 06-107	Cast Iron/Bare Steel Replacement Program (“CIBS”)	• Excludes projects required by public works projects or as part of main encroachment program • $500,000 base expenditure • Base rate surcharge	

NEW JERSEY	Authority	Title	Scope	Notes
Statewide	Section 14:7-1.20(d)	Capital Infrastructure Investment Program	• "Capital Adjustment Charge" • Allows for tracker, but requires job creation targets and reporting	
PSE&G	GO09010050	Capital Investment Program ("CIP")	• Combination of recovery through "Capital Adjustment Charge" tracker and rolling in to base rates at next rate case • 200 miles cast iron and bare steel mains and associated services • Bill impacts ranging from $1.43 monthly to $9.42 annually	• Requires quarterly reports, reports on number of jobs created
Southern Jersey Gas	GO09010051	Capital Investment Recovery Tracker ("CIRT")	• $103 million • Combined tracker reduction and increase in base rates • Not limited to leak prone pipes, available for any projects that assist in providing safe, adequate and proper service, are incremental to the annual capital budget and support NJ stimulus objectives including job growth	• Requires quarterly reports, reports on number of jobs created
New Jersey Natural Gas	GO09010052	Accelerated Infrastructure Investment Program ("AIP")	• $70.8 million • Not limited to leak prone pipes • Recovered through base rates	• Requires quarterly reports, reports on number of jobs created
Elizabethtown	GO09010053	Utility Infrastructure Enhancement Cost Recovery Rider ("Cost Recovery Rider")	• 2 years; $60.4 million • Not limited to cast iron and bare steel, but does include • Combined tracker and rolling in to base rates at next rate case	• Requires quarterly reports, reports on number of jobs created
NEW YORK				
Central Hudson	09-G-0589	Infrastructure Enhancement	• $19.3 million budget for 3 years • Deferred regulatory asset	• Penalty for failure to spend $6 million annually
OHIO				
Duke Energy	01-1228-GA-AIR	Accelerated Main Replacement Program	• 1200 miles of cast iron and bare steel over a 10 year period • $716 million	
Columbia Gas of Ohio	08-72-GA-AIR	Infrastructure Replacement Program Rider	• Cast iron, bare steel and wrought iron as well as associated steel or metallic service lines, risers, customer owned service lines and automatic meter reading devices • Effective for 5 years	• Includes an O&M offset • Surcharge was capped from small general service customers. $1.10 /month in year 1; $2.20/month in year 2; $3.20/month in year 3; $4.20/month in year 4; $5.20/month in year 5.
Vectren Energy	07-1080-GA-AIR	Distribution Replacement Rider	• Cast iron and bare steel and certain risers • Effective for 5 years	• Includes an O&M offset • Cap on monthly charge

Appendix B — continued — Replacement Programs

OHIO	Authority	Title	Scope	Notes
Dominion East	09-458-GA-RDR	Pipeline Infrastructure Replacement	• Cast iron, bare steel, wrought iron and copper and associated infrastructure • Cap on monthly charge to customers	• Includes an O&M offset • Requires Dominion to assume ownership of all customer-owned lines • Provides opportunity for PUC and other stakeholders to review PIR plan • Requires study assessing the impact of the program on safety and reliability
OREGON				
Northwest Natural	PUC Order # 01-843, Docket # UM1030		• Bare steel • 20 year program	
RHODE ISLAND				
National Grid	Docket No. 4034	Gas Infrastructure Safety and Reliability Plan ("Gas ISR")	• Small diameter cast iron mains, bare steel mains and bare steel inside high pressure services; also includes cathodic protection, valves, cast iron joint encapsula-tion • 45 miles; 2,125 services proposed for 2012	• Estimated customer impact of $7.47 for the year • Requires consultation with the Office of Consumer Advocate in preparing the plan • Quarterly reports
TENNESSEE				
Statewide			• The Tennessee Regulatory Authority has replacement programs in place for each gas utility	
TEXAS				
Statewide	16 TAC § 8.209	Distribution Facilities Replacements	• Risk based program requirements for operators of gas pipes • Steel service line leak repair analysis and replacement requirements • Minimum 5% annual replacement of the pipelines/facilities that pose the greatest risk	• Allows for recovery for new lines as well
Atmos Energy		GRIP	• Consistent with statute	
CenterPoint Energy		GRIP	• Consistent with statute	
Texas Gas Service		GRIP	• Consistent with statute	
UTAH				
Questar	Docket No. 09-057-16	Infrastructure Rate Adjustment Tracker	• Allows for replacement of aging high pressure feeder lines with new high pressure feeder lines • Incremental surcharge	• Quarterly progress reports

VIRGINIA	Authority	Title	Scope	Notes
Atmos Energy Corp.	VCC No. URS-2009-00326	Replacement	• Settlement agreement; requires replacement of all identified risers by the end of 2011 and the company's 8,700 feet of cast iron pipe in the state by the end of 2012	• Based on settlement of alleged safety violations
Washington Gas	PUE-2011-00049		• Settlement Agreement; require-ment to leak survey all bare steel and cast iron pipes by end of 2011 for baseline	• Based on settlement of alleged safety violations
Columbia Gas	PUE-2011-00049			
WASHINGTON				
Puget Sound Energy	WUTC Order No. 2 PG-030080 PG-030128	Bare Steel Replace-ment Program	• Settlement agreement; requires replacement of bare, non-cathodically protected steel pipe by 2014	• Based on settlement of alleged safety violations
Puget Sound Energy	UG-110723	Investigation	• Cost recovery proposal for pipeline investments rejected; WUTC initiates investigation into required steps to deal with older pipe.	

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