Lost and Unaccounted for Gas

FINAL

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Prepared for
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Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AGA	American Gas Association
BTU	British Thermal Unit (a measure of energy)
CEC	California Energy Commission
CFR	Code of Federal Regulations
CLF	Conservational Law Foundation
CMR	Code of Massachusetts Regulations
CO_2	Carbon Dioxide
DOT	U.S. Department of Transportation
DPU	Massachusetts Department of Public Utilities
DTE	Massachusetts Department of Telecommunications and Energy (now DPU)
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse Gas
GRI	Gas Research Institute (now the Gas Technology Institute)
GTI	Gas Technology Institute
GWP	Global Warming Potential
GWSA	Global Warming Solutions Act
ICF	ICF International
LAUF	Lost and Unaccounted for Gas
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LP	Liquefied Propane
MassDEP	Massachusetts Department of Environmental Protection
Mcf	Thousand cubic feet (of gas)
MMcf	Million cubic feet (of gas)
MT	Metric ton
M&R	Metering and Regulating
NARUC	National Association of Regulatory Utility Commissioners
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRV	Pressure Relief Valve
PSIG	Pounds Per Square Inch Gage

Acronym / Abbreviation	Stands For
SCF	Standard Cubic Feet (of gas)
SIT	State Inventory Tool
SQ	Service Quality
TIRF	Targeted Infrastructure Recovery Factor

Executive Summary

The Massachusetts Department of Public Utilities ("DPU") commissioned ICF International (ICF) to conduct a study regarding both lost and unaccounted for gas ("LAUF") and methane emissions from the gas distribution system in Massachusetts. Among other things, the study concludes that LAUF is not an appropriate surrogate for methane emissions, and that methane emissions from the three service territories of the two gas distribution companies studied range from 0.6 to 1.1 percent of total gas received.

Purposes of the Study

The purposes of the study are to:

- Identify the components of LAUF and current state and federal reporting practices for LAUF.[1]
- Understand and quantify the components used in LAUF estimates, including the components that result in methane emissions,[2] using data provided by local gas distribution companies.
- Make recommendations regarding improvements for calculating LAUF and methane emissions.
- Make recommendations regarding improvements for reporting LAUF and methane emissions.
- To the extent possible, quantify the methane emissions from the natural gas distribution system in Massachusetts and the LAUF from three service territories of the two gas distribution companies studied.
- Make recommendations for reducing LAUF and methane emissions from the natural gas distribution system in Massachusetts.

LAUF vs. Lost Gas vs. Methane Emissions

This study is important for several reasons, but one of the most important is because it distinguishes three concepts that are routinely confused: (1) LAUF, (2) lost gas, and (3) methane emissions. In so doing, it clarifies significant issues related to methane emissions from the state's gas distribution system.

- "LAUF" refers to the difference between the *total* amount of gas that a gas distribution company purchases and the amount it delivers to customers. It includes all components of loss, such as leakage, venting, theft, and gas used by the distribution company itself, adjusted by some companies for meter errors, billing cycle issues, and other considerations. LAUF is essentially an accounting concept.
- "Lost gas" refers to all natural gas that escapes from the distribution system. For example, all vented gas is lost to the distribution system, but stolen gas does not escape from the distribution system and does not count as "lost." Lost gas is a subset of LAUF.[3]
- "Methane emissions" refers to the methane portion of natural gas that actually *reaches the atmosphere*. It is important to understand that not all LAUF or even lost gas results in methane emissions. For example, some leaking gas never reaches the atmosphere, and thus does not end up as "methane emissions" (although it is "lost"). Methane emissions are a subset of lost gas (and therefore also of LAUF).

In summary, methane emissions are a subset of lost gas, and lost gas is a subset of LAUF.

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[1] We discovered that there is in fact inconsistency among various state and federal agencies as to the characterization of the components of LAUF.

[2] Methane is the principal component of natural gas, and a much more potent greenhouse gas than carbon dioxide.

[3] We include lost gas here because it is important to understand its relationship to LAUF and to methane emissions. However, we focus in this study not on lost gas itself but, rather, on the component of lost gas that has climate implications, i.e., methane emissions.

The distinction between LAUF and methane emissions, in particular, is important. Understanding LAUF is essential because customers pay for it and it provides information about the efficiency of a distribution company's operations. Also critical in understanding the difference is that not all of the LAUF has methane emissions implications, which is what is of concern from a climate perspective.[4]

Approach of the Study

The study uses data provided by two Massachusetts gas distribution companies, with three service territories that are reasonably representative of the state. It analyzes LAUF using a "top-down" approach. The top-down approach disaggregates LAUF into its components and quantifies the components. The study uses a bottom-up approach to estimate both lost gas and methane emissions, using information such as miles of pipeline, number of services, and number of meters, as well as an emissions factor for each component of the distribution system.

Although some of the emissions factors used in this study are the same as those used in other reports, this study is particularly significant in developing new emissions factors, as warranted, using publicly available data.

Findings of the Study

- The study identified 12 LAUF components, with the largest being company use, meter bias, billing cycle adjustments, and fugitive emissions[5].
- LAUF, as currently defined by the DPU and reported by the local distribution companies, is neither an accurate representation of the amount of natural gas lost from the system nor an appropriate surrogate for methane emissions.
- The accuracy of methane emissions estimates partially depends on the accuracy of the emissions factors used. Currently available emissions factors for some components of LAUF have significant uncertainty.
- LAUF for the two gas distribution companies (comprising three service territories) involved in the study ranges from −0.2 to 2.6 percent, [6] lost gas ranges from 0.6 to 1.8 percent, and methane emissions range from 0.6 to 1.1 percent of total gas received.
- Extrapolating to the entire state from the LAUF figure for the two companies is not possible because of the wide variation in how companies collect data and account for adjustments.
- Using available data from the DPU and other public sources, the lost gas and methane emissions were estimated for the entire state. In 2012, approximately 7.0 billion standard cubic feet of lost gas and 5.4 billion standard cubic feet of methane were emitted. Converting these numbers to percentages, however, would result in a high degree of uncertainty, both because of the imprecision in extrapolating the numbers and because the study has limited confidence in the total statewide volume of gas received.
- Replacement of leak-prone gas mains with plastic would result in a dramatic reduction in the amount of methane emissions.

Recommendations of the Study

- The DPU should not use LAUF, as currently defined in Massachusetts, to draw conclusions about the efficiency of natural gas distribution systems. (Section 4.1.1)

[4] In addition, we note that not all methane emissions (i.e., the gas that actually gets to the atmosphere) have public safety implications. For example, non-hazardous gas leaks have climate but not safety implications.

[5] Fugitive emissions include unintentional releases from pipelines, metering and regulating stations, and customer services (lines and meters), not caused by an accident.

[6] Incomplete or inaccurate accounting of the LAUF components accounts for the negative value for LAUF.

- The DPU should provide clear guidance for the methods and factors used to estimate LAUF, and work with the Massachusetts Department of Environmental Protection (MassDEP) and other agencies to improve guidance for the methods and factors used to estimate methane emissions from the distribution system. (Section 4.2.1 bottom paragraph)
- The DPU should standardize the calculation and reporting of LAUF. (Section 4.1.3)
- The DPU should develop a mechanism for improved reporting of LAUF and emissions. One option is to require more detailed reporting of LAUF as a service quality measure. (Section 4.1.2)
- Gas distribution companies should quantify the contribution of each component of LAUF that adds significantly to the total in all DPU proceedings and reports. (Section 4.1.3)
- The DPU should build awareness of the differences between LAUF and methane emissions through the DPU, the Department of Energy Resources, and the MassDEP fact sheets and updated definitions in regulations and guidance. (Section 4.1.4)
- The DPU should work with gas distribution system operators to develop a testing program to pressure test a representative sample of pipeline being replaced to develop more accurate emissions factors for different types of pipelines. (Section 4.2.2)
- Gas distribution system operators should implement best management practices recommended by the U.S. Environmental Protection Agency's [EPA] Natural Gas STAR Program. (Section 4.3)

1. Background

The Massachusetts Department of Public Utilities (DPU) is responsible for natural gas utility oversight, including monitoring the service quality of local gas utility companies (also known as local distribution companies, or LDCs), regulating the safety of gas pipelines, and ensuring that gas utility consumers are provided with the most reliable service at the lowest possible cost. This oversight includes issues related to "lost and unaccounted for" (LAUF) gas, which is a priority for the Department because of its potential to affect customer service quality, rates, public safety, and the environment.

The natural gas distribution sector contributes to greenhouse gas emissions (GHG) through both the intentional and the unintentional release of methane, and the DPU is in a unique role to understand and address the emissions. To fulfill its mission, the DPU is committed to the development of accurate, consistent, and transparent estimation of LAUF and of methane emissions from the natural gas distribution system.

1.1. What Is LAUF?

LAUF is used primarily as an accounting mechanism to balance the receipts and deliveries of gas. LAUF is the difference between the *total* gas that a gas distribution company purchases and the amount it ultimately delivers to customers. It includes all components of loss, such as leakage, venting, theft, and gas used by the distribution company itself, adjusted by some companies for meter errors, billing cycle issues, and other considerations.

LAUF values are reported publicly in several forms. LAUF includes many different components, including but by no means only, methane emissions to the atmosphere. Recently, several published analyses have noted the magnitude and effects of LAUF and methane emissions from natural gas distribution systems. A summary of these analyses is presented in Appendix B1.

1.2. LAUF Definitions Vary by State and Organization

As shown in Table 1-1, various organizations, agencies, and states define LAUF differently. As a result, an individual company may not calculate LAUF consistently within each area where it operates or report the same value of LAUF for all reporting requirements in a single year. Even within a state, LAUF definitions can vary by the type of administrative proceeding, and result in multiple LAUF percentages reported by one company within the same year.

Table 1-1: Definitions of Lost and Unaccounted For Gas

U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA)
From PHMSA Form F 7100.1-1 "Unaccounted for gas" is gas lost; that is, gas that the operator cannot account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to allow reasonable calculation or estimate; or other similar factors. • Report for the 12 months ending June 30 of the reporting year. • Do not report "gained" gas. If a net gain of gas is indicated by the calculations, report "0%." [(Purchased gas + produced gas) minus (customer use + company use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent unaccounted for.

American Gas Association
Glossary Definition Unaccounted for Gas: The difference between the total gas available from all sources, and the total gas accounted for as sales, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times. In cycle billings, an amount of gas supply used but not billed as of the end of a period.
U.S. Energy Information Administration
Glossary Definition Lost and Unaccounted for Gas: Represents differences between the sum of the components of natural gas supply and the sum of components of natural gas disposition. These differences may be due to quantities lost or to the effects of data reporting problems. Reporting problems include differences due to the net result of conversions of flow data metered at varying temperatures and pressure bases and converted to a standard temperature and pressure base; the effect of variations in company accounting and billing practices; differences between billing cycle and calendar-period time frames; and imbalances resulting from the merger of data reporting systems that vary in scope, format, definitions, and type of respondents. Reported on a calendar year basis.
Massachusetts Department of Public Utilities
Annual Return Item 72: Calculation of Unaccounted for Gas in the Annual Return is the difference between the total sendout and the total sold plus transported, less the amount used by the company. Calculated on a calendar year basis. **Service Quality Guidelines** D.P.U. 12-120 (Proposed July, 11 2014), Attachment A "Unaccounted-for Gas" means the differential between the amount of gas that enters the Company's city-gates, and the amount of gas billed to customers, expressed as a percentage of the amount of gas that entered the Company's city-gates. D.T.E. 99-84 (current Service Quality Guidelines) "Unaccounted-for Gas" shall mean the reduction in the quantity of natural gas flowing through a pipeline that results from leaks, venting, and other physical and operational circumstances on a pipeline system. Unaccounted-for Gas is also referred to as a line loss.
Pennsylvania Department of Public Utilities
52 PA Code § 59.111 Definition The difference between the total gas available from all sources and the total gas accounted for as sales, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperatures or pressures or both, and other variants, particularly billing lag. UFG = Gas received – Gas Delivered – Adjustments Adjustments must be individually identified by category (such as company use, calculable losses from construction, purging, storage migration, other temperature and pressure adjustments, and adjustments for heat content of natural gas). Adjustments must be supported by metered data, sound engineering practices, or other quantifiable results that clearly support the utility's need for the adjustment. Adjustment must be consistent from filing to filing.

1.2.1. Differing LAUF Calculations and Components

The Pipeline and Hazardous Materials Safety Administration (PHMSA) definition allows LDCs to include adjustments in the calculation of LAUF provided they are supportable and can be appropriately estimated. PHMSA does not allow companies to report negative values for LAUF during the 12 months ending June 30 of the reporting year.

The calculation of LAUF is also included on the Energy Information Administration (EIA) Form 176, Annual Report of Natural and Supplemental Gas, and includes estimates of facility and compressor use, new pipeline fill volumes, other consumption of gas in operations (undefined), and losses from leaks, damage, accidents, and "blow down," using best estimates. LAUF is reported on a calendar-year basis.

The calculation of LAUF in the Massachusetts DPU Annual Return (Item 72) is based on the Uniform System of Accounts for Gas Companies provided at 220 Code of Massachusetts Regulations [CMR] 50, also known as the

"Brown Book." This regulation describes the requirements of the financial accounting system that LDCs must maintain for reporting and auditing purposes. The regulation does not explicitly include a definition of LAUF, but provides the requirements for accurate and complete accounting of the volume of gas received, gas used for utility operations, and gas sold to customers. According to the DPU, companies can exercise some flexibility in the interpretation of the definitions of the accounts and may or may not include line losses in the volume estimates. This regulation, originally promulgated in 1921, was last revised in 1961.

Several states[7]—including Pennsylvania, Texas, New York, and Connecticut—have taken actions to clarify the definitions and reporting of LAUF, or establish numerical limits or ranges on the amount of allowable LAUF in rate recovery. The Pennsylvania regulations, promulgated in 2013, provide a uniform definition of LAUF to be used in all Commission proceedings, as well as a list of specific components that must be included in the calculation of LAUF. The Pennsylvania regulation is unique in that it specifies the components to be considered in LAUF and provides a requirement for justification of assumptions and estimates.

Many components contribute to the total amount of LAUF reported by a company. Table 1-2 provides a list of the components that ICF identified and included in this report.

Table 1-2: Components of Lost and Unaccounted for Gas Calculation

Category	Sources	Description of Source
Receipts	Purchased	Gas that is purchased from an outside entity, usually a transmission company. This gas passes through a city gate or take station and is metered by the transmission company, the LDC, or both. These values are recorded continuously.
	Produced	Gas produced by entities owned by the LDC and sent directly to the distribution system. These sources are usually metered daily.
	Storage	Gas that is injected or withdrawn from storage (either underground, in tanks, or liquefied natural gas [LNG]) and is sent into the distribution system. This gas is metered daily.
	Non-metered Gas	Gas that enters the LDC system that is not metered, typically gas transferred from an adjacent division.
Deliveries	Residential	Gas that is purchased by residential customers. This gas is metered by the LDC and the meters are read regularly (20- to 40-day cycle).
	Commercial and Industrial	Gas that is purchased by commercial or industrial customers. This gas is metered by the LDC and the meters are read every month.

[7] The NRRI report provides a summary of the LAUF regulations in these and many other states. The reader is referred to this report for a more thorough discussion of the regulatory status of LAUF. Lost-and-Unaccounted for Gas: State Utility Commission Practices. Available at: http://www.narucmeetings.org/Presentations/Presentation-on-LAUF-Gas%20-NARUC-Gas-Subcommittee-November-17-2013-Costello.pdf

Category	Sources	Description of Source
	Transport gas	Gas that passes through an LDC system, but is not owned by the LDC. This gas is usually gas that the LDC is contracted to move for a third party, and may include its own LAUF allowance.
Adjustments	Company (Own) Use	Gas that is used by the LDC, including gas for building heat, backup power generation, and use in process equipment, such as line heaters.
	Storage/Withdrawal Adjustments	"Accounting" adjustments to the inventory of stored natural gas within the distribution system. Generally associated with LNG liquefaction and vaporization. Can be positive or negative.
	Soft Closes	Gas that is used at a location, but not explicitly billed to a customer. This situation usually occurs when a tenant moves out and the gas is not shut off between occupants, but can also include commercial customers' meters.
	Theft	Gas that is stolen from the system, often by illegally accessing the distribution pipes or bypassing the meter.
	Line Pack Changes	The line pack is the amount of gas that is contained in the distribution system pipelines. Changes can occur by varying the temperature and pressures of the pipelines and when new pipes are added to the system.
	Intentional Venting	The intentional release of gas to the atmosphere. Usually through a designed vent (e.g., a pneumatic device) or during pipeline maintenance and repair.
	Dig-Ins/Mishaps	The unintentional release of gas from external damages to the pipeline.
	Meter Bias	Correction to account for the average bias of the meters in the system. This value can be positive or negative, depending on whether the meter is running fast or slow.
	Billing Cycle Adjustments	Correction to account for the fact that monthly billing cycles do not exactly coincide with the LAUF reporting cycles.
	Composition Corrections	Inaccuracy resulting from conversion of gas volumes to heat content of gas delivered.
	Distribution System Emissions	Fugitive emissions from pipelines, metering and regulating stations, and services.
	Adjustments for Non-metered Gas	Any non-metered sources of gas consumption (e.g., municipal gas streetlights) must be estimated. Usually, very few of these sources exist, but such sources can contribute to uncertainty in the LAUF calculation.

1.2.2. Variability in Massachusetts LAUF Reporting

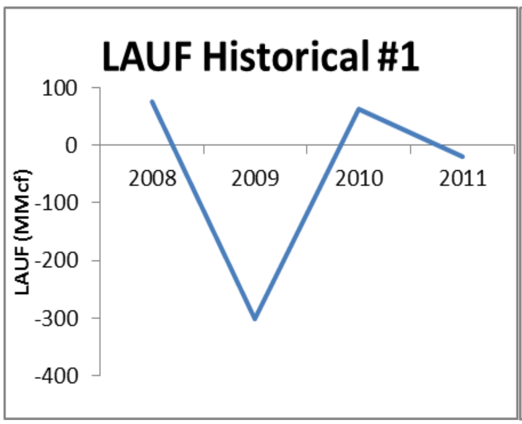
Given the different components of LAUF and the range of interpretations, the reported values vary widely across different reporting agencies. For example, Table 1-3 shows the LAUF values reported by five Massachusetts utility companies to various agencies in 2012.

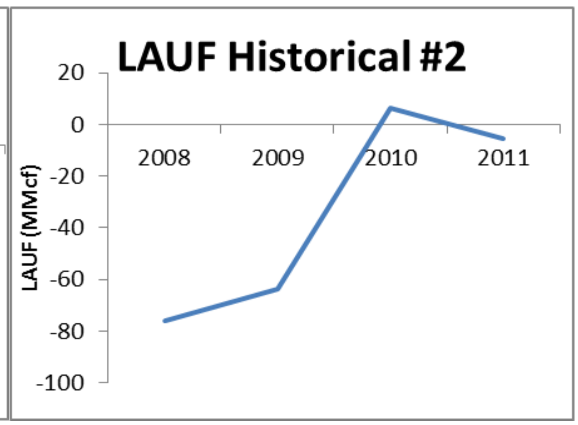
Table 1-3: Unaccounted for Gas as Reported to Different Agencies from the Same Company in 2012

Company	MA DPU Annual Return	PHMSA Form 7100	EIA Form 176[1]
A	1.54%	1.45%	1.25%
B	2.60%	1.62%	2.2%
C	0.53%	0%	0.1%
D	4.55%	3.52%	-30.9%
E	1.35%	1.30%	9.2%

[1] Percentage calculated by dividing Unaccounted for (Line 20) by Total Supply (Line 7)

A review of LAUF reports from 2008 to 2011 indicated large variability and inconsistency in reported values. These large fluctuations in month-to-month and year-to-year values may be exacerbated by the highly variable nature of certain components such as billing cycle lag and the identification of stolen gas. The graphs in Figure 1-1 illustrate the reported LAUF values for three LDCs between 2008 and 2011, as reported to EIA. The variability ranges from positive (lost gas) to negative (gained gas—as a physical matter, an impossibility). In 2012, the DPU data showed the LAUF reported in the Annual Returns for 11 LDCs represented between 0.007 percent and 32.8 percent of throughput, with an average of 4.5 percent.





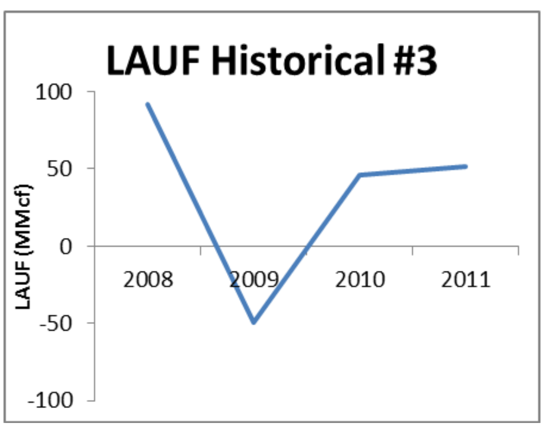


Figure 1-1: Variability in Lost and Unaccounted for Values Reported to EIA 2008–2011

Note: Values reported in thousand cubic feet (MCF). Source: EIA Form 176 Item 20, 2008–2011

Yet even when companies use a standard reporting requirement, there remains a wide range of LAUF values. For example, Table 1-4 is a summary of LAUF information from 21 Massachusetts companies (not limited to distribution companies) as reported to EIA via Form 176 for the year 2011.

Table 1-4: Unaccounted for Gas as Reported to EIA in 2011 by Massachusetts Companies

Value of LAUF Reported	Count of Companies	Cumulative LAUF Reported Billion Cubic feet (of gas)
Positive	7	4.93
Zero	5	0
Negative	9	-2.82
Total	***21***	***2.12***

Note: 13 of the 21 reporting companies are LDCs under the jurisdiction of the DPU. Other reporters include transmission companies and LNG facilities. Some LDCs submit separate reports for different operating areas.

LDCs in Massachusetts interpret the definition of LAUF differently, which is partly a function of the type of data the LDCs collect and maintain. Larger utilities with a large customer base (or those that operate in multiple states) have more sophisticated systems and tend to collect data that are more detailed to evaluate their systems and operations. Smaller utilities, however, may not have the resources to collect and analyze data for all the components that make up the adjustments aspect of LAUF. The initial Information Request for this study was sent to all LDCs operating in Massachusetts and included a question on how LAUF is calculated for their operations. The responses, summarized in Table 1-5, demonstrate the wide variation in the level of detail LDCs apply to estimate and report LAUF.

Table 1-5: How Massachusetts LDCs Calculate Lost and Unaccounted for Gas

Company	Response
A	Company tracks purchases and sales, LAUF is adjusted for leaks estimated using EPA published emissions factors. This is done on a 12-month basis.
B	Company compiles throughput (purchases and storage) and “gas accounted for” (sales and company use) and subtracts the two to determine LAUF.
C	Company tracks throughput (gas received) and sales (gas used) and subtracts the two to determine LAUF, on a 12-month basis. (Note – further review of the company procedures indicated a comprehensive methodology for calculating LAUF addressing numerous contributing components.)
D	Company subtracts sales from purchases and makes no other adjustments.
E	Company calculates LAUF in accordance with the company’s tariff terms and conditions and includes difference between the sum of amount received and the amounts delivered, less gas consumed by the company for its own purposes, line losses, and gas vented and lost as a result of an event.
F	Company compares the monthly meter receipts and the department’s internal LNG meter readings to determine its purchased volumes, less monthly gas sales volumes, third-party damage loss, venting and purging operations, and plant use.
G	Subtract physical outputs from physical inputs. No adjustments are made.
H	Company tracks purchases and deliveries and subtracts sales to determine LAUF. No adjustments are made.

Company	Response
I	Company subtracts sales volumes, damage losses, venting/purging, and plant use from meter receipts at the gate station, on a monthly basis.

Note: Responses from Information Request IR-PL 1-2

This research makes apparent that the definitions of LAUF vary widely and that the methods for estimating the magnitude of various LAUF components are not well defined.

1.3. Why LAUF is Important

In Massachusetts, all 11 LDCs (7 investor-owned and 4 municipally owned utilities) are required to report their monthly and annual LAUF values as part of their Annual Returns. The DPU can use the LAUF values to evaluate accounting practices and to identify operational efficiency issues. The current service quality guidelines for gas utilities (DTE Order 99-84) require the reporting of unaccounted-for gas, per the definition provided in Table 1-1. The requirement is only for reporting unaccounted for gas; the value is not considered a performance measure, nor is it subject to penalties or penalty offsets.

Nationally, the LAUF values reported though PHMSA and EIA are publicly available and have been used in studies to evaluate the overall efficiency of gas distribution and to assess infrastructure investment needs. As noted earlier, however, these national LAUF values are sometimes referenced improperly as a surrogate for methane emissions.

Although variability in the current methodology for estimating LAUF is significant, the concept of LAUF is primarily valuable for providing an initial estimate of the accounting accuracy and operational efficiency of a natural gas system. A single value for LAUF, however, may not be a robust tool for policy development or other decision-making given the broad LAUF definitions, the lack of a uniform methodology for measuring and calculating each component, and the unique situation of each LDC.

1.4. LAUF versus Methane Emissions

LAUF is an umbrella term that *includes* lost gas and methane emissions. Avoiding the use of these terms interchangeably is crucial. Lost gas and methane emissions are both subsets of LAUF. Lost gas refers to all natural gas that escapes from the distribution system. Methane emissions, however, are only the methane component of natural gas that reaches the atmosphere because of gas lost from the distribution system. Thus, methane emissions are the natural gas that reach the atmosphere due to gas lost from the distribution system, given adjustment for the methane content of natural gas and the amount of methane that is oxidized in the soil after escaping from the system.

Although a system's methane emissions are a critical component of LAUF, LAUF includes many other components (including billing cycle adjustments and meter bias), which can be significantly larger than methane emissions. As such, LAUF is not an accurate representation of the methane emissions from a gas distribution system. Figure 1-1 and Table 1-4 show that the calculation of LAUF can even result in negative numbers. This situation occurs due to gas measurement errors or an artifact of billing cycles—not because gas is gained in the pipeline system from the atmosphere.

During EPA's development of the Greenhouse Gas Reporting Program rule, subpart W,[8] which applies to seven sectors of the oil and gas industry including natural gas distribution systems, EPA responded to a commenter who suggested that LAUF could be used as a surrogate for methane emissions estimates. EPA disagreed and provided the following response.[9]

> EPA disagrees on the use of LUAF [LAUF] as a surrogate for greenhouse gas emissions data collection … there are other multiple components associated with LUAF [LAUF], such as inaccuracies of gas measurement, and thus would not provide the desired level of data accuracy and quality to achieve the objectives of [the reporting] rule. Most importantly, because LUAF [LAUF] would not identify the exact sources of the emissions, there would be further inadequacies for informing future policy. Finally, no current studies exist that accurately define the percentage of LUAF [LAUF] that is emissions from a system.

Throughout this report, we carefully distinguish between LAUF, lost gas, and emissions. Our literature review and analytical work revealed significant differences between how lost gas and methane emissions are defined, calculated, and applied. For the purposes of this study, "lost gas" refers to natural gas that has been either intentionally or unintentionally released from the distribution system. Not all gas released from distribution pipelines reaches the atmosphere; some of it is broken down in the soil. A study by EPA and the Gas Research Institute (GRI)[10] provides soil oxidation factors for gas released from distribution pipelines by type of pipe material. Although the amount of soil oxidation is debated, recognizing the difference between lost gas and methane emissions is essential. Gas lost from the system includes methane (which is the primary component of natural gas), but is by no means synonymous with methane emissions plus other gases such as ethane, propane, carbon dioxide, and nitrogen. Figure 1-2 shows the relationship between lost gas and methane emissions.

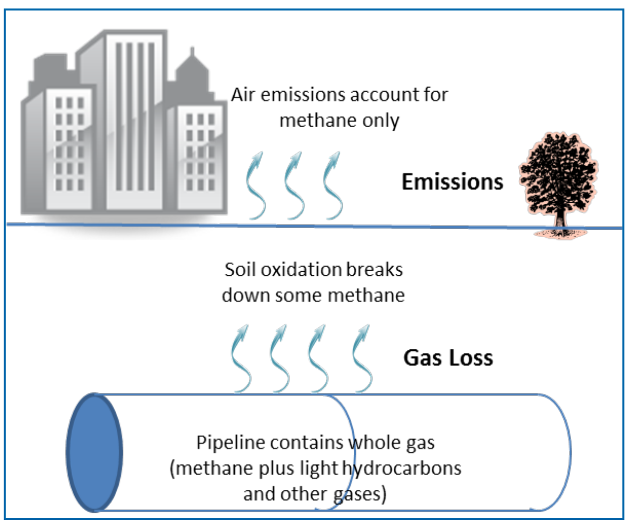


Figure 1-2: Schematic of Lost Gas and Methane Emissions

[8] 40 CFR 98.230

[9] Comment Number: EPA-HQ-OAR-2009-0923-1059-12 Organization: Montana-Dakota Utilities Co. Commenter uses LUAF as the acronym for Lost and Unaccounted for Gas.

[10] *Methane Emissions from the Natural Gas Industry, Volume 9 – Underground Pipelines*, EPA and GRI, June 1996, available at http://www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf

A summary of the differences between LAUF, lost gas, and methane emissions as used in this report appears in Table 1-6.

Table 1-6: Comparison of Lost and Unaccounted for, Lost Gas and Methane Emissions

Measurement Type	Soil Oxidation Factor Used	Gas Type	Brief Description
LAUF	Never Applied	Natural Gas	LAUF is the difference between the total amount of gas received and the gas delivered to customers.
Lost Gas	Never Applied	Natural Gas	Lost gas is natural gas that has either intentionally or unintentionally escaped from the distribution system.
Methane Emissions	Always Applied	Methane Portion of Natural Gas	Methane emissions are methane gas that has either intentionally or unintentionally escaped from the distribution system and reaches the atmosphere.

1.5. Related Issues and Reports

The Massachusetts Executive Office of Energy and Environmental Affairs and its subordinate agencies—the DPU, the MassDEP, and the Massachusetts Department of Energy Resources—are actively engaged in discussions and actions to address issues related to ratepayer fairness, pipeline safety, long-term energy and fuel supply, and methane emissions reductions as a strategy to reduce the effects of climate change. These agencies regularly use publicly available data on methane emissions and LAUF to support decision-making.

1.5.1. Massachusetts Global Warming Solutions Act

In 2008, Governor Deval Patrick signed the Global Warming Solutions Act (GWSA), which provided a framework for reducing emissions of greenhouse gases from 1990 baseline levels by 25 percent by 2020 and by 80 percent by 2050.[11] The GWSA directed the Executive Office of Energy and Environmental Affairs to set GHG reduction requirements across all sectors of the economy and established an Advisory Committee to help oversee and guide implementation of the actions. Key aspects of the GWSA include:

- A baseline assessment of statewide GHG emissions in 1990, which will be used to measure progress toward meeting the emissions reduction goals of the Act. This requirement is administered by MassDEP and includes the Massachusetts Greenhouse Gas Emissions Inventory (described below).
- A projection of the likely statewide GHG emissions for 2020 under a “business-as-usual” scenario that assumes that no targeted efforts to reduce emissions are implemented.
- New regulations requiring reporting of GHG by the Commonwealth’s largest sources by January 1, 2009. This requirement, the Massachusetts Greenhouse Gas Reporting Program, is administered by MassDEP and is further described below.
- Target emissions reductions that must be achieved by 2020, and a plan for achieving them.

Methane emissions from the natural gas distribution sector are included in these actions and are an important part of the baseline estimate, the reporting program, and the emissions reduction plan.

[11] Commonwealth of Massachusetts (2008a). Chapter 298 of the Acts of 2008: An Act Establishing the Global Warming Solutions Act.

1.5.2. The Massachusetts GHG Emissions Inventory

The Massachusetts Greenhouse Gas Emissions Inventory is the basis for establishing the emissions baseline year (1990), projecting "business-as-usual" emissions for 2020, and tracking progress made under the GWSA. The emissions estimates are prepared by MassDEP using the State Inventory Tool (SIT), designed by EPA specifically to generate high-level statewide estimates of emissions. The SIT is a spreadsheet-based model that includes 11 modules to calculate GHG emissions across all sectors of the economy. The SIT provides some default data for each state and affords users the option of applying state-specific data. The methods used and the sectors covered are the same as those in the EPA GHG Inventory. One module of the SIT enables users to forecast emissions through 2030 based on historical emissions generated from the sector-specific modules. The projection incorporates future energy consumption, population, and economic factors to generate annual emissions estimates for each sector.

The State Inventory includes an estimate of statewide emissions for natural gas distribution systems, created by the natural gas and oil module of the SIT. The inventory includes emissions from cast iron, unprotected steel, protected steel, and plastic mains (and from unprotected steel and protected steel services). The remaining emissions are estimated using an emissions factor that estimates emissions from plastic and from other services, meters, and metering and regulating stations. This emissions factor is based on the total number of services in the distribution system. Within the module, the user may select the pre-loaded default emissions factors for various pipeline materials or enter state-specific emissions factors. Other factors used to calculate emissions, such as the number of miles of each type of pipe material, number of customers, number of compressor stations, and other system data are collected or estimated from published data provided by PHMSA, EIA, and the DPU. Although the SIT provides a simple, streamlined, transparent, and consistent methodology for developing and updating statewide emissions estimates, it is not intended to provide a detailed calculation of emissions from the natural gas distribution sector, LDCs, or geographical areas of the state. The reader is referred to the MassDEP website[12] for more details and the most recent State Inventory.

The 2011 Inventory (which is the latest complete annual inventory published) reports 82,204 metric tons of methane emissions from the Massachusetts Natural Gas and Oil sector, of which the distribution sector accounts (according to the Inventory) for approximately 80 percent; the remaining emissions are from transmission systems. During the same period, total emissions in Massachusetts were reported as 80 million metric tons of CO_2e.[13] Of this total, the natural gas distribution sector accounted for 1.7 percent of the total methane emissions, a 9-percent reduction compared to the Massachusetts baseline year of 1990. An additional 14-percent reduction is projected by 2020.

1.5.3. Massachusetts Greenhouse Gas Reporting Program

The Massachusetts GHG Reporting Program was promulgated in support of the GWSA and is administered by the MassDEP in accordance with the MassDEP regulations.[14] Key aspects of the regulation include:

- Emissions sources that emit greenhouse gases in excess of 5,000 tons of greenhouse gases per year in CO_2e must report annually.

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[12] http://www.mass.gov/eea/agencies/massdep/air/reports/emissions-inventories.html

[13] Carbon dioxide equivalent (CO_2e) is a measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP). The CO_2e value for a gas is derived by multiplying the tons of the gas by its associated GWP. The GWP for methane is 21.

[14] The reporting program is described in Section 2 of MGL 21N. MassDEP regulations for the program are provided in 310 CMR7.71.

- Any facility that is required to report air emissions data to the Department under Title V of the federal Clean Air Act must report annually.
- The Climate Registry General Reporting Protocol provides the methodologies that must be used to calculate emissions.
- If a facility is required to report under the EPA Greenhouse Gas Reporting Program (40 Code of Federal Regulations [CFR] part 98), the same methodology must be used for reporting the emissions under the Massachusetts GHG Reporting Program. This reporting protocol is much more rigorous than that required by the Climate Registry for natural gas distribution systems.
- Emissions calculations must be verified by a third party.
- Facilities not required to report may report voluntarily.

The Massachusetts GHG Reporting Program is not directly related to activities and oversight of the DPU; however, it is included in this discussion to demonstrate the wide use of emissions estimates related to the natural gas distribution sector. Within the natural gas distribution sector, eight LDCs reported to the Massachusetts GHG Reporting Program in 2012.[15] The reporting program is considered a high-level inventory of sources in the state and (for companies not reporting under EPA Greenhouse Gas Reporting Program subpart W) uses a simplified estimation method for calculating emissions under The Climate Registry General Reporting Protocol. The Massachusetts GHG Reporting Program differs from the Massachusetts Inventory in that the estimates are provided by the emitting facility owner/operator, not MassDEP, and there is a threshold limit of 5,000 tons for reporting. The Massachusetts GHG Reporting Program has limited but specific guidance on preparing emissions estimates for the natural gas distribution sector. The website[16] for the reporting program provides a thorough discussion of the program and results.

1.5.4. The U.S. EPA Greenhouse Gas Reporting Program (40 CFR part 98)

The mandatory EPA Greenhouse Gas Reporting Rule (40 CRF part 98)[17] requires the reporting of GHG data from large emissions sources and suppliers in various industry segments across the United States. Key aspects of this rule include:

- Facilities that emit more than 25,000 metric tons of CO_2e of GHGs are required to report.
- The rule applies to facilities that are direct GHG emitters, fossil-fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground.
- Forty-one industrial categories are covered, including the petroleum and natural gas industry.
- In 2012, 8,206 unique facilities reported.
- The rule, which contains subparts that apply GHG emissions to each industrial category, provides the methodologies that must be used to calculate or estimate emissions.
- Companies must report activity and supporting data, not just emissions.
- Data were first collected in 2010, and available data are published by EPA.[18]

[15] The most recent report can be found at: http://www.mass.gov/eea/docs/dep/air/climate/12facghg.pdf
[16] http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/approvals/ma-greenhouse-gas-emissions-reporting-program.html
[17] The most recent rule can be found at: http://www.ecfr.gov/cgi-bin/text-idx?SID=f9d5d3b745ad8bd7ff69cd145a2da052&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl

Although the EPA GHG Reporting Program is not directly related to activities and oversight of the DPU, it is included to demonstrate the national approach being used to collect and analyze appropriate GHG emissions data. The expectation of the mandatory Greenhouse Gas Reporting Program is that 85 to 90 percent of U.S. GHG emissions will be covered by this rule. Several issues related to the program's data collected so far, however, limit the data's accuracy and applicability. First, through the 2012 reporting year, facilities were allowed to estimate emissions from many sources using Best Available Monitoring Methods instead of the prescribed methodologies in the rule. Second, although the EPA requires the use of certain activity data for calculating emissions, reporting these data has not always been required. Third, not all facilities are covered due to the 25,000-metric ton CO_2e limit. For example, only five LDCs in Massachusetts reported to the program in 2012. Fourth, LDCs must conduct leak surveys of aboveground custody transfer stations, but are given 5 years to conduct their surveys. Because 5 years has not elapsed since this rule was enacted, not all transfer stations may have been surveyed and reported. Finally, the data reported by facilities does not require third-party verification.

Several other related issues and reports that incorporate aspects of LAUF and emissions are provided in Appendix B. These include (1) New Massachusetts legislation regarding leak classification and reporting; (2) discussion of existing leak-prone infrastructure, and (3) state incentive programs for reducing LAUF and emissions.

[18] Online data can be found at: http://www.epa.gov/enviro/

2. Scope and Approach

2.1. Objectives and Scope of the Study

The activities performed in support of this study included data collection, quantitative and qualitative analysis of data, interpretation of results, and development of recommendations. The objectives of the study were to:

- Identify the components of LAUF and current state and federal reporting practices for LAUF.
- Understand and quantify the components used in LAUF estimates, including the components that result in methane emissions, using data provided by local gas distribution companies.
- Make recommendations regarding improvements for calculating LAUF and methane emissions.
- Make recommendations regarding improvements for reporting LAUF and methane emissions.
- To the extent possible, quantify the methane emissions from the natural gas distribution system in Massachusetts and the LAUF from three service territories of the two gas distribution companies studied.
- Make recommendations for reducing LAUF and methane emissions from the natural gas distribution system in Massachusetts.

The study uses data provided by two Massachusetts gas distribution companies, with three service territories that are reasonably representative of the state. The natural gas distribution system includes all infrastructure and related operations between the take or gate stations (where gas is transferred from the transmission to the distribution system) to the company-owned meter at a customer location. The study does not include losses and emissions from residences and commercial facilities on the customer side of the gas meter. The study evaluated emissions and LAUF in 2013; however, for some analyses data from previous years and early 2014 were required.

To maintain focus on the most significant issues related to the two areas of concern (LAUF and emissions) and manage the available resources and schedule, the study did not include analysis of transmission pipeline systems for natural gas (interstate and intrastate), liquefied petroleum gas plants, or liquefied natural gas terminals. Some components of liquefied natural gas operations directly associated with the distribution systems (such as local peak shaving plants[19] for vaporization and liquefaction) were considered and evaluated as an integral part of the analysis.

The study is intended to identify the issues all Massachusetts LDCs face in calculating LAUF and methane emissions from distribution systems, based on ICF's analysis of a representative sample of the gas distribution systems in Massachusetts. Operational practices among investor-owned LDCs and among municipally owned gas companies differ significantly. Additionally, attributes such as geography, distribution system size and complexity, age and type of pipelines, instrumentation and recording equipment, billing and accounting systems, staffing, and investment strategies vary considerably among the 11 LDCs in Massachusetts and result in a wide range of practices and priorities.

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[19] A peak shaving LNG plant is used to level the supply and demand of natural gas by liquefying and storing natural gas during periods of low demand, and vaporizing and re-injecting the gas into the distribution system during peak periods of demand. There are approximately 20 such plants in Massachusetts. Some peak shaving plants receive LNG by truck during periods of high demand.

2.2. General Approach

ICF followed a systematic approach to identify the issues of concern, collect the appropriate data, and analyze results. The approach included the following steps:

- ICF reviewed available public documents to determine how Massachusetts and other states define and regulate LAUF. Additional research was conducted to determine if other states have addressed the challenges with transparency and consistency in reporting. ICF also reviewed literature from Europe to identify studies of LAUF in natural gas distribution systems.
- Through the Massachusetts DPU, ICF requested information from all 11 LDCs operating in Massachusetts for general practices in estimating and reporting LAUF and methane emissions (Information Request IR-PL-1, 12 items). Nine LDCs provided responses.
- ICF reviewed and catalogued responses to the information request and developed a list of data needs for calculating LAUF and estimating methane emissions from distribution system.
- Two LDCs volunteered to participate in the study. ICF and the DPU met with these two companies to learn about their distribution system and select three study service territories for detailed LAUF and methane emissions analysis. The selected service territories are reasonably representative of the LDC distribution system statewide. In selecting the study areas, ICF used the following criteria:
    - Whether the system represents the general types of equipment present throughout Massachusetts (e.g., pipeline materials, metering and regulating stations, peak shaving LNG facilities);
    - Whether the system is isolated, that is, the number of gas receipt points (gate station location(s) or custody transfer station(s)) from the transmission system is finite. These systems include no interconnects with other systems.[20] Within the large pipeline grid, an isolated system simplifies the quantification of gas within the system at any particular time;
    - Whether the system serves a large customer base that includes residential, industrial, and commercial users; and
    - Whether operating and engineering data for the system are available electronically and could be provided to DPU for the study.
- ICF reviewed the information provided by the two companies and began data analysis and calculations using available information. ICF identified additional data needs and developed additional questions regarding operations and data within the three selected service territories. Through the DPU, ICF requested detailed engineering and operational information for the three service territories selected for detailed LAUF and emissions analysis.
- ICF prepared initial estimates of LAUF and emissions for the three service territories and identified additional data needs to understand and quantify results and uncertainties more fully. Several supplemental Information Requests and discussions were conducted to fill the data gaps.
- ICF quantified values of LAUF components and methane emissions for the three service territories and conducted further analysis of the results. ICF compared lost gas to LAUF values and evaluated the magnitude of components contributing to LAUF. Based on these results, ICF developed recommendations to improve the calculation and reporting of LAUF, lost gas, and emissions.

[20] Company B Division 2 had one interconnect with an adjacent system.

- Results of the analysis and preliminary recommendations were presented and discussed with DPU. ICF prepared a draft report, which the DPU reviewed.
- Results and recommendations are documented in this final report.

2.3. Top-down and Bottom-up Approaches

"Top-down" and "bottom-up" approaches were applied to the data sets simultaneously to analyze the natural gas distribution systems. ICF employed a top-down approach to quantify the components and uncertainties in LAUF calculations, and a bottom-up approach to generate an estimate of methane emissions from the distribution system. The top-down approach was also used to establish whether the bottom-up approach provided a reasonable estimate of lost gas (and hence methane emissions from the system).

The bottom-up approach used the engineering characteristics of the distribution system to estimate lost gas and methane emissions from individual sources such as pipelines, metering and regulating stations, services, intentional venting, and dig-ins. This approach provided a consistent methodology to estimate methane emissions from the distribution systems in the study, such that reported methane emissions and losses are comparable between systems.

A more thorough discussion of the top-down and bottom-up methodologies is provided in Chapter 3 – Analysis and Findings.

2.4. General Comment on the Study Approach

This study is unique in that it provides a comprehensive quantitative analysis of both LAUF and methane emissions simultaneously using top-down and bottom-up approaches, and analyzes the relationship between the two to identify opportunities for improving the calculation and reporting in each. The methodology and emissions factors used for calculating emissions are based on the best available information and do not necessarily represent the most commonly accepted values, or even those that are defined by regulations. To our knowledge, no similar study has been conducted or published to address, comprehensively and quantitatively, the issues of consistency, accuracy, and transparency in LAUF and methane emissions calculation and reporting from natural gas distribution systems.

3. Analysis and Findings

3.1. Methodology for Analysis of Three Divisions' Distribution Systems in Massachusetts

ICF used two simultaneous approaches to quantify the magnitude of LAUF components and lost gas at two different companies covering three distinct division distribution systems. The first method, referred to as the top-down analysis, attempted to quantify all known receipts, deliveries, and adjustments made to the divisions' distribution systems. The difference between the receipts to the system and the deliveries plus adjustments was considered the LAUF. The second method, referred to as the bottom-up analysis, directly calculated all lost gas and methane emissions from the divisions' distribution systems, including both fugitive and vented sources, using activity data provided by the companies (miles of mains, counts of services, etc.) in conjunction with publicly available emissions factors.

The two companies involved in the analysis volunteered to participate in the study. They are referred to as Company A and Company B, and the divisions are referred to as Division 1, Division 2, and Division 3. In this analysis, Company A owns and operates Division 1, and Company B owns and operates Divisions 2 and 3.

3.1.1. Top-down Analysis

The top-down approach disaggregated the total LAUF into its components—measurement error, billing cycle adjustments, theft, fuel use, and other components, using operational and billing data supplied by the two companies and quantified using as many of the receipts, deliveries, and known adjustments as possible from the data provided. The top-down approach had a twofold objective:

- The first was to determine the level of contribution of each LAUF component to the total LAUF. This determination was made by quantifying each LAUF component using system-specific data.
- The second was to determine the expected range of LAUF using a process of elimination. The assumption is that, once all known LAUF components are accounted for, what remains in the LAUF is either lost gas or uncertainties in calculating LAUF components.

The components analyzed in the top-down approach varied slightly among the three areas studied because of differences in system design, operations, and data collection. For example, none of the service areas in the study had in-system storage capability. One company that provided information for the study areas did not collect data to support estimation of losses due to soft closure[21] or theft and also did not estimate losses from dig-ins and mishaps.

This methodology did not attempt to estimate emissions from the system using emissions factors or any other estimation methodology. The reason the calculated value continues to contain uncertainty is because the various receipts, deliveries, and adjustments all have inherent uncertainty. The components associated with the receipts, deliveries, and adjustments are shown in Figure 3-1.

A detailed description of the data received from the companies and the methodology used to quantify each LAUF component is provided below. For the purposes of this study, the period between July 1, 2012 and June 30, 2013 was chosen for analysis. The data for the receipts and customer use were used as provided, assuming no adjustments had been made prior to receipt. Any adjustments made to the data prior to ICF's receipt would add uncertainty to the analysis.

3.1.1.1. Inputs/Receipts

Gate Station Receipts

Both companies provided daily gate station receipts on a volume basis in thousand cubic feet (Mcf). The receipts were aggregated for the days between July 1, 2012 and June 30, 2013. Gas custody is transferred from the transmission company to the distribution company at the gate station. The meters at the gate stations are constantly monitored and periodically calibrated because the gas sales volume metered is directly tied to the financial transaction between the transmission and distribution companies. The gas receipts at the gate stations, for the purposes of this report, were assumed to represent the receipts accurately, and all LAUF calculations were conducted with the receipts as the pivotal number.

Uncertainty – Gate station receipts have uncertainty in the readings, depending on the accuracy of the meter. Additional uncertainty in this value comes from any unmetered gas coming into the system. These meters are typically pressure- and temperature-compensated meters that help reduce the error of the meter reading.

Liquefied Natural Gas (LNG) Send Out

LNG send out is gas generated from LNG regasification that is introduced to the LDC pipeline system. Each company provided daily receipts in Mcf from LNG plant stations that service the division. These data were aggregated for the days between July 1, 2012 and June 30, 2013.

Liquefied Propane Gas Send Out

Propane is sometimes added to the natural gas supply to supplement volumes and provide higher heat value. Each company provided daily receipts in Mcf from liquefied propane stations.[22] These data were aggregated for the days between July 1, 2012 and June 30, 2013.

[21] A soft closure occurs when a tenant (either residential or commercial) moves out and the gas is not shut off between occupants. In soft closure, some gas is used for pilot lights or is leaked, but the use is not explicitly billed to a customer.
[22] One company had no propane air stations in use during the analysis period and one company had four stations in use, accounting for a very small amount of the total gas supply for their system.

Inputs/Receipts

- Gate Station Receipts
- LNG Send Out
- Storage Withdrawals
- Non-metered Gas Received

Outputs/Deliveries +/- Adjustments

- Customer Use
- Company Use
- Venting/Dig-Ins
- Theft
- Line Pack Changes
- Meter Bias
- Billing Cycle Adjustments
- Gas Storage
- Compositional Corrections
- Non-metered Gas Delivered

Unaccounted For Gas (Fugitive Emissions plus Uncertainty)

- Uncertainty in measured values
- Fugitive emissions from leaking components
- Unaccounted for sources due to lack of information

Figure 3-1

Inputs/Receipts

- Gate Station Receipts
- LNG Send Out
- Storage Withdrawals
- Non-metered Gas Received

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Outputs/Deliveries +/- Adjustments

- Customer Use
- Company Use
- Venting/Dig-Ins
- Theft
- Line Pack Changes
- Meter Bias
- Billing Cycle Adjustments
- Gas Storage
- Compositional Corrections
- Non-metered Gas Delivered

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Unaccounted For Gas (Fugitive Emissions plus Uncertainty)

- Uncertainty in measured values
- Fugitive emissions from leaking components
- Unaccounted for sources due to lack of information

Figure 3-1: Top-down Analysis Methodology

Storage Withdrawals

The companies stated that there was no storage of gas (either aboveground or underground) within the division boundaries, so this factor was not evaluated in this study. The LNG stations in Divisions 1 and 2 received gas from outside the systems that were analyzed. Therefore, deliveries from the LNG stations to the divisions are simply treated as receipts to the divisions.

Non-Metered Gas Received

Most natural gas systems receive gas from a transmission line at a single gate station where it is metered. Some natural gas distribution companies, however, connect to adjacent service areas to ensure an adequate supply of gas is available for customers within the division. Companies with multiple divisions sometimes do not meter gas when gas is transferred to a different division. Therefore, gas can enter the system but not be accounted for in gate receipts. This gas must be considered in LAUF calculations, as it increases the amount of incoming gas. For this study, the non-metered received gas volume was estimated using average design volumes provided by Company B for Division 2. Division 1 and Division 3 were isolated divisions and had no unmetered gas entering the system.

Uncertainty – Division 2 had unmetered gas coming into the system, so design volumes were used to estimate this unmetered volume. These design values have a much higher uncertainty than actual meter readings, as the design values do not necessarily represent the actual volume transferred.

3.1.1.2. Outputs/Deliveries

Customer Use

The companies each provided data for customer bills received, in both therms[23] and Mcf delivered. Weighted average therm factors also were provided to convert between Mcf and therms. Customer use was aggregated in Mcf for the days between July 1, 2012 and June 30, 2013 based on billing date.

Uncertainty – Customer use has uncertainty in each meter reading, depending on the accuracy of the meter. Customer meters must meet the DPU accuracy standard of ±2 percent for refurbished gas meters.[24] New meters purchased by LDCs must meet a more stringent standard of ±1 percent.[25] Some of these meters compensate for pressure and temperature, but generally have more uncertainty than the meters that record receipts. Additional uncertainty in customer use derives from any unmetered gas leaving an LDC system for another LDC system, as described in Non-Metered Gas Received description in Section 3.1.1.1. This source adds more uncertainty into the LDC volumes.

Company Use

Each company provided data for company use. Company A provided data for total gas used between July 1, 2012 and June 30, 2013. Company B provided data on a monthly basis in both therms and Mcf. For Company A, gas used was determined from a fuel record or calculated using the equipment heat rating and the operating hours. These values then were converted to Mcf using a weighted average therm factor for the entire year. For Company B, the Mcf data were used as reported. All company use between July 1, 2012 and June 30, 2013 was aggregated.

When aggregating the data, there were several exceptions to the methodology stated above. Gas used at an LNG facility, other than specifically for the gate station, was excluded from company use because the LNG facility, as noted above, is outside the system boundary. Additionally, data for Division 3's compressed natural gas station use were provided only for March 2012 to February 2013. The compressed natural gas use for Division 3 was assumed similar during July 1, 2012 to June 30, 2013. Furthermore, the compressed natural gas use represented a small fraction of company use.

Uncertainty – Company use has uncertainty in the accuracy of the meters that record the gas used and in the calculation methods used to determine gas use. In addition, the data provided were assumed to include all gas use for company buildings and any other company use of gas, including vehicles and gas line heaters. Company A stated, however, that it has company buildings in Division 1, but whether these were included in the company use data provided is unclear. For example, some of the fuel was used by "heaters," and whether building heaters were included or if these were just gate station heaters for incoming gas is unclear.

[23] A commonly used unit of heat energy equivalent to 100,000 British thermal units (BTU). One therm of energy is created by burning approximately 100 cubic feet of natural gas.
[24] Massachusetts General Laws. c.164, § 103: Accuracy of meters; records.
[25] 220 CMR 36.

Soft Closes

Company A provided information on consumption of gas during soft closes for July 1, 2012 to June 30, 2013. This number was used directly in the report. Company B did not collect or provide information on soft closes.

Gas Storage

Each company stated no gas storage occurs within the division boundaries, so this factor was not evaluated in this study.

Theft

Company A provided data on estimated theft between July 1, 2012 and June 30, 2013. The estimated theft for this period is similar to what was billed back due to lawsuits that concluded in that year, further supporting the estimated value of theft. The estimated theft value was used as reported. Company B did not estimate theft and had no records that could be used for this report.

Uncertainty – Theft estimates are uncertain, as the theft values used in the analysis were "found theft" that was allocated to the estimated period in which the theft occurred. This value omits theft that was not found. For the purposes of this analysis, the companies' allocations of theft to the given period were used as reported.

Line Pack Changes

Each company provided data to estimate the line pack changes. Line pack is the amount of gas contained in the distribution system pipelines. Changes in line pack can occur when the temperature or pressure of the pipeline is changed, or when new pipe is added to the system. Companies provided the total feet of newly installed mains and services by pipe diameter and operating pressure. Each new main or service must be filled with gas when installed, and this additional gas is accounted for in this category. Further, any additional pipeline that is replaced also must be refilled before returning to operation, and this volume also is included here. The overall line pack volume was calculated using the following equation:

$$L_P = \left(\frac{\frac{d}{2}}{12}\right)^2 * \pi * l * \frac{P + 14.7}{14.7}$$

Where:

L_P	=	Volume of gas necessary to fill pipeline (standard cubic feet [scf])
d	=	Internal diameter of pipeline (inches)
l	=	Length of pipeline isolated during replacement (feet)
P	=	Operating pressure of pipeline (pounds per square inch, gage)

Company A provided a replacement schedule, including length and operating pressure of pipeline replaced. It was assumed that the replaced pipe was isolated at the length specified by the replacement schedule (e.g., if 700 feet of pipe was replaced, only 700 feet was isolated). The provided pipeline lengths and operating pressures then were used to determine the amount of gas needed to fill the replaced mains. Additionally, any new services added during the year were included in this calculation. The company provided information on diameter and pressure of the services, but no information on service length. Therefore, an assumption was made that each service was 70 feet long.

Company B provided the miles of new mains installed and their corresponding operating pressures for 2014, as well as the total miles of mains at each operating pressure for both 2013 and 2014. To determine the total line pack change to the system, ICF accounted for both the new mains added and any mains that changed operating pressures. The calculation for new mains, described by the equation above, was straightforward. For mains that changed operating pressures, ICF compared the miles of mains at each operating pressure between 2013 and 2014, making sure not to double count the new pipe added in 2014. From this comparison, ICF could determine how much pipe changed operating pressure, and the corresponding line pack change could be calculated. This calculation was performed by first taking all positive changes (i.e., any pressures that experienced an increase in the number of miles) and calculating the line pack change via the equation above. Second, any negative changes (i.e., any pressures that experienced a decrease in the number of miles) also were calculated via the same equation. Finally, the negative changes were subtracted from the positive changes to obtain a net line pack change. This net change was the line pack change due to operating pressure changes. The value for new mains and the value for operating pressure changes then were combined into a single line pack change value. As noted, the data were provided on a calendar-year basis for 2013 and 2014 and, therefore, the adjustments from 2013 to 2014 were assumed representative of July 1, 2012 to June 30, 2013. This source was unlikely to change substantially from year to year and, further, this source was not a significant source of emissions.

Uncertainty – The line pack volume is uncertain because, when pipe is installed, a variety of techniques can be used to seal off pipeline mains. The technique used affects the volume of the pipeline that needs to be filled with gas. Because the information on each section of pipe installed did not include information on the technique used for isolating the pipeline section, ICF made assumptions as stated above when estimating the total volume of gas for the line pack calculation. The assumptions made for the calculations for Company A regarding the length of pipeline isolated during repairs adds to the uncertainty of the calculation.

Venting/Dig-Ins

This source comprises multiple sources, including pipeline and service venting for replacements, pneumatic devices, and pipeline dig-ins.

For pipeline venting during replacement, the same methodology applied in line pack changes above was used. For Company A, the volume of pipe isolated during replacement, per the above-described methodology, was assumed to be vented to the atmosphere. No assumption was made, however, on venting attached services. Because no pipeline replacement schedule was provided for Company B, ICF assumed that the same length of pipe was vented as that needed to be filled from new installations in the line pack calculation. Based on this assumption, the amount of gas assumed to be vented for pipeline replacements is equal to the amount of gas necessary to fill the new mains and services as described in the line pack calculation.

For services removed during the year, Division 1 provided information on diameter and pressure of the services, but no information on service length. Therefore, an assumption was made that each service was 70 feet long. Divisions 2 and 3 provided no information on services removed.

Only Company A in Division 1 used gas-driven pneumatic devices and provided the bleed rate associated with these devices. Therefore, pneumatic-device emissions were estimated only for Division 1.

Finally, the estimated gas lost due to pipeline dig-ins was provided by Division 1 for July 1, 2012 to June 30, 2013. This value was used directly, but includes only dig-ins that were billed to individuals and therefore does not account for all gas lost due to dig-ins. Divisions 2 and 3 did not estimate the gas lost from dig-ins and made no information available that would allow for an estimation of gas lost from dig-ins.

Meter Bias

All distribution companies are required to replace their customer meters once every 7 years. Any meter found to be outside the allowable ±2-percent error range is either replaced or refurbished and calibrated before being reintroduced into the system. This testing provides an indication of meter bias across the system.

Each company provided results from tested customer meters that provided the percentage by which each meter was running fast or slow. A slow meter indicates that the customer is receiving more gas than is being metered, and vice versa for fast meters. If a meter was running 2 percent slow, the test reading was 98 percent, and if the meter was running 2 percent fast, the test reading was 102 percent. These test values were averaged over the entire data set during July 1, 2012 to June 30, 2013. The average percentage was used as an adjustment factor to the customer deliveries to account for how fast/slow the meters were running in the system. This adjustment was done using the following equation:

$$A_{ME} = \frac{M_{EP} - 100}{100} * D$$

Where:

A_{ME}	=	Adjustment made to the meter bias (scf)
M_{EP}	=	Average meter bias percentage from all meters between July 1, 2012 to June 30, 2013 (%)
D	=	Customer deliveries recorded between July 1, 2012 and June 30, 2013 (scf)

For analysis, ICF was provided with two data sets for recorded meter testing results. The first data set (Data Set 1) was provided by the DPU from files submitted by LDCs, and showed the number of meters grouped in 2-percent tolerance intervals. In this data set, the number of meters within the acceptable accuracy range was aggregated, which did not allow for analysis of meter bias within the ±2-percent range, which was most of the meters. The data did allow for gross analysis of the number of meters outside the acceptable range, both positive and negative. To obtain a more granulated version of the DPU data, companies provided the raw measured meter data (Data Set 2). For Company B, however, these two data sets did not correspond to each other, showing opposite results. Data Set 1 was an aggregated summary of all the meters in the system tested in a given month. In Data Set 1, 5.3 percent of meters were running above 2 percent (fast), while 1.5 percent of the meters were running below 2 percent (slow) during July 1, 2012 to June 30, 2013. The results show that more meters were running fast than slow. In Data Set 2, the raw data for each meter reading was provided; however, 1.7 percent of the meters were shown to be running fast and 2.1 percent were running slow. The average meter in Data Set 2 ran slow.

To evaluate meter bias, the team used Data Set 2 because it was more granulated. Why a discrepancy in the data sets exists is unclear and which data set was more accurate is not indicated. The discrepancies cause uncertainty in the meter bias adjustment value used for Divisions 2 and 3. A summary of the discrepancies between the two data sets is presented in Table 3-1.

Table 3-1: Meter Testing Summary for Divisions 2 and 3 for July 1, 2012 to June 30, 2013

Breakdown of Meter Bias	Percent of Meters in Data Set 1	Percent of Meters in Data Set 2
>10% Slow	0.3%	0.2%
4.1–10% Slow	0.4%	0.5%
2.1–4% Slow	0.9%	1.4%

Breakdown of Meter Bias	Percent of Meters in Data Set 1	Percent of Meters in Data Set 2
Within 2% Limits	93.2%	96.3%
2.1–4% Fast	4.6%	1.0%
4.1–10% Fast	0.5%	0.4%
>10% Fast	0.2%	0.3%

Billing Cycle Adjustments

Because customer meters are read only once per month, sometimes a lag occurs between when the gas was used and when it is accounted for in LAUF calculations. For example, a customer may be billed for gas in the beginning of July, but actually may have used most of the gas in June. Each company provided an associated billing period for each bill or group of bills. To account for gas that was actually used during the LAUF calculation period (July 1, 2012 to June 30, 2013), the gas for each bill was assumed used uniformly across each day in the billing period. Once the gas was allocated to each day, all gas used during the LAUF calculation timeframe was aggregated. This value was then compared to the 12 months of billed gas volumes to establish the effect that billing cycle lag has on the LAUF calculation.

Uncertainty – In the data set for Company B, some bills covered an extended period, in some instances covering several months or even years. For these longer periods, the billing adjustment was done in the same way as described above. Assuming a constant level of gas use, however, is less valid over longer periods. For Division 2, more than 19,800 Mcf of gas was billed in a bill that either started or ended more than 2 months outside of the study period. For Division 3, over 53,600 Mcf of gas was billed similarly. These long billing periods provide uncertainty, as correlate these bills to the period that the gas was actually used is difficult.

For all three divisions, the billing cycle adjustments were between 0.01 percent and 0.3 percent of total receipts. The magnitude in the billing cycle lag can vary, depending on the calculation methodology and, more importantly, when the cut-off for the reporting year occurs. For Division 1, ICF calculated the billing cycle lag several different ways to show how different approaches can affect the overall LAUF calculation. The first methodology (described earlier) was that used in the ICF LAUF calculation. The second methodology used a weighted average of the daily gas receipts during a billing cycle to allocate gas used per day. This calculation methodology theoretically should more closely align with gas actually consumed on each day. This method was not used for all of the divisions, however, due to the way the billing data were presented for Divisions 2 and 3. The third methodology examined calculating the billing cycle adjustment (using the methodology described in Section 3.1.1.2) on a calendar year basis instead of the July 1, 2012-to-June 30, 2013 basis. The results are shown in Table 3-2.

Table 3-2: Comparison of Billing Cycle Adjustments Calculations

Methodology	1	2	3
Timeframe	July 1, 2012 to June 30, 2013	July 1, 2012 to June 30, 2013	January 1, 2012 to December 31, 2012
Daily Averaging Method[1]	Straight	Weighted	Straight
Adjustment[2]	0.06%	0.18%	0.35%

[1] A straight average divided the gas billed by the number of days in the billing cycle. A weighted average used the daily gas receipts to allocate the monthly billed volume by day.
[2] A positive adjustment indicated that more gas was actually used in the LAUF calculation period than accounted for.

This analysis shows that calculating LAUF on a calendar-year basis results in more error than an annual calculation starting July 1. This outcome is to be expected because gas use is at its highest in the winter (i.e., in December and January, when a calendar-year reporting period would end) and also can be highly variable during that time. Comparing the straight versus weighted average calculation methodologies shows this adjustment factor can have large variations, depending on the method used. That the weighted average methodology adjustment is higher than the straight average methodology could indicate that even more gas is being used in the reporting period than previously thought.

Compositional Corrections

If gas is provided on a heat-content basis, there can be a small error in converting to a volumetric basis, usually attributed to rounding or averaging in the conversion factors. For this analysis, all gas was provided on a volumetric basis, so no compositional corrections were needed. The data for receipts and customer use were used as provided, assuming no adjustments had been made prior to receiving the data. If the meter readings were put in the system and converted from Mcf to therms and back prior to ICF's receiving the data, this would add uncertainty into the analysis.

Non-Metered Gas Delivered

One company providing data for the study noted that adjacent divisions sometimes do not meter gas when gas is transferred between divisions. Therefore, gas can leave the system but not be accounted for in deliveries. This gas should be taken into consideration in LAUF calculations because it decreases the outgoing gas, but this gas is not lost gas. This delivered gas volume was estimated using average design volumes provided by Division 2. Division 1 and Division 3 were isolated divisions and did not have unmetered gas entering the system.

Uncertainty – The estimate for Division 2 has uncertainty because the design volumes may not necessarily reflect the gas that actually was transferred between Division 2 and the larger company gas system.

3.1.2. Bottom-up Analysis

The bottom-up analysis estimated lost gas and methane emissions by using activity factors [26] and emissions factors from all sources within the divisions being studied. The activity data for each division were provided by the companies. The emissions factors were obtained from public reports that have developed emissions factors. In some instances, data sets from multiple reports were combined to create new emissions factors. The bottom-up analysis was used to first estimate lost gas. This lost gas value then was adjusted for methane content and soil oxidation to estimate methane emissions.

The emissions sources from the bottom-up analysis can be separated into two categories: vented emissions and fugitive emissions. Vented emissions occur when gas is intentionally released from the system, such as when a pipeline is vented for maintenance. Fugitive emissions are the unintentional release of gas from the system, such as through leaks in the pipelines. The emissions sources considered in this analysis are presented below.

- Vented Emissions:
    - Pipeline blowdowns;
    - Pipeline dig-Ins; and
    - Pressure relief valve (PRV) releases.

[26] See Section 3.1.2.2 for a discussion of the activity factors used in the study.

- Fugitive Emissions:
  - Mains (cast iron, cast iron – plastic lined, plastic, protected steel, unprotected steel);
  - Services (copper, plastic, protected steel, and unprotected steel);
  - Meters (residential, commercial, and industrial); and
  - Metering and regulating stations.

3.1.2.1. Emissions Factors

Historically, emissions factors from the natural gas distribution sector have come from the 1996 study conducted jointly by the EPA and the GRI. For most sources in the petroleum and natural gas industry, that report contains emissions factors that are widely accepted as industry standards. Several studies, however, have been conducted in the time since this report was written, usually focusing on specific emissions sources in the industry. To compile the most complete and updated list of emissions factors for this analysis, many of these newer reports, along with the 1996 EPA/GRI report, were reviewed. Of the reports analyzed, four contained sufficient data and explanation to be included in this analysis.

1996 EPA/GRI Study

This study is considered the industry standard for emissions factors in the petroleum and natural gas industry. Data for this study were collected between 1992 and 1995, using a variety of methods. For sources such as mains and services, this study used a leak statistics method to quantify emissions rates. For metering and pressure regulating stations, the study used a tracer gas method. For other sources, such as maintenance and other irregular venting, the study estimated emissions using services records and site visit data. For the gas distribution sector, this report contains emissions factors for nearly all of the major emissions sources, including:

- Pipeline mains, broken out by type (cast iron, plastic, unprotected steel, protected steel);
- Services, broken out by type (copper, plastic, unprotected steel, protected steel);
- Pipeline venting;
- Pipeline dig-ins;
- Pressure relief valve venting;
- Metering and regulating station fugitives, broken out by pressure grouping and location (above ground or vault); and
- Customer meter fugitives, broken out by type (residential, commercial/industrial).

For pipeline mains and services, the 1996 EPA/GRI Study reports emissions to the atmosphere, assuming soil oxidation of methane to carbon dioxide occurs. When calculating lost gas, the soil oxidation of methane must be removed from these emissions factors. Using the data from the study, lost gas emissions factors were developed for this report.

Comgás Study – "New Measurement Data Has Implications for Quantifying Natural Gas Losses from Cast Iron Distribution Mains"

This study was conducted by Comgás of São Paulo, Brazil. This study focused solely on fugitive emissions from cast iron mains. During Comgás' pipeline replacement program from 2005 to 2009, the company pressure tested their cast iron mains before retiring them, to develop a new fugitive emissions factor. From this study, Comgás measured the leak rate from 912 sections of cast iron mains and developed a new emissions factor of 803,548 scf/mile-year.

2009 GTI/AGA Report – "Field Measurement Program to Improve Uncertainties for Key Greenhouse Gas Emission Factors for Distribution Sources"

This report was published in 2009 by the Gas Technology Institute (GTI) for the American Gas Association (AGA). This study focused on updating and improving emissions factors for sources in the gas distribution segment. Data for this report were collected between 2007 and 2009 from week-long field surveys conducted at six LDCs and from an additional commercial meter testing program. For all sources, emissions were first identified using infrared cameras, gas detectors, and soap bubble solution and then measured directly using a high-volume sampler. GTI collected emissions data for the following sources:

- Custody transfer stations;
- Pressure limiting stations;
- District regulating stations; and
- Meters (residential, industrial, and commercial).

ICF Report – Review of the API Compendium for Oil and Gas Operations in California: Phase 2 Draft Report

This ICF report for the California Energy Commission (CEC), which reviewed the emissions sources listed in the API Compendium, specifically recommended an update to the emissions factor for plastic mains. Plastic mains that were constructed and installed prior to 1982 were found to be more prone to cracking due to brittleness. After 1982, an American Society of Testing Materials standard was developed to ensure reliable quality in plastic pipes. This greatly reduced the cracking of pipes, resulting in lower emissions from plastic mains. This report specifically examined the data collected on plastic mains from the 1996 EPA/GRI study and data collected for the CEC. The conclusion was that the 1996 EPA/GRI study potentially contained data points from pre-1982 pipe. With these data points removed, and including the data from the CEC, the updated emissions factor for plastic mains was greatly reduced from the emissions factor listed in the 1996 EPA/GRI study.

Selection of Emissions Factors

The emissions factors for lost gas used in this analysis are displayed in Table 3-3. Note that the emissions factors shown in this table used to calculate lost gas are not corrected for soil oxidation or methane content. Emissions factors for estimation of methane emissions are also shown in Table 3-3. For most sources, the emissions factors used were derived from one of the reports discussed above. In some instances and for specific emissions sources, however, the raw data from multiple reports were combined to develop new emissions factors. These sources include cast iron mains and residential and commercial meters. The process for selecting the individual emissions factors is discussed below.

Table 3-3: Lost Gas and Methane Emissions Factors for Bottom-up Analysis

Category	Source	Type	EF Lost Gas	EF Methane Emissions	Units	Source
Mains[1]	Pipeline Blowdowns	Vented	109	102	scf/mile-yr	1996 EPA/GRI
	Pipeline Dig-Ins		1,702	1,590	scf/mile-yr	1996 EPA/GRI
	PRVs		54	50	scf/mile-yr	1996 EPA/GRI
	Cast Iron	Fugitive	795,098	443,345	scf/mile-yr	Comgás/GRI
	Cast Iron - Plastic Lined		9,475	8,672	scf/mile-yr	ICF CEC Study
	Plastic		9,475	8,672	scf/mile-yr	ICF CEC Study

Category	Source	Type	EF Lost Gas	EF Methane Emissions	Units	Source
	Protected Steel		3,384	3,066	scf/mile-yr	1996 EPA/GRI
	Unprotected Steel		120,131	110,183	scf/mile-yr	1996 EPA/GRI
Services[2]	Copper		272	254	scf/service-yr	1996 EPA/GRI
	Plastic		10	7	scf/service-yr	1996 EPA/GRI
	Protected Steel		189	172	scf/service-yr	1996 EPA/GRI
	Unprotected Steel		1,821	1,682	scf/service-yr	1996 EPA/GRI
Meters	Residential		91	85	scf/meter-yr	GTI/AGA-EPA/GRI
	Commercial		468	437	scf/meter-yr	GTI/AGA-EPA/GRI
	Industrial		217,985	203,598	scf/meter-yr	GTI/AGA Study
Metering and Regulating Stations - By Pressure Grouping	M&R[3] >300 psig		1,686,347	1,575,048	scf/station-yr	1996 EPA/GRI
	M&R 100–300 psig		896,634	837,456.	scf/station-yr	1996 EPA/GRI
	M&R <100 psig		40,330	37,668	scf/station-yr	1996 EPA/GRI
	Regulating >300 psig		1,518,463	1,418,244	scf/station-yr	1996 EPA/GRI
	Regulating >300 psig Vault		12,193	11,388	scf/station-yr	1996 EPA/GRI
	Regulating 100–300 psig		379,850	354,780	scf/station-yr	1996 EPA/GRI
	Regulating 100–300 psig Vault		1,876	1,752	scf/station-yr	1996 EPA/GRI
	Regulating 40–100 psig		9,379	8,760	scf/station-yr	1996 EPA/GRI
	Regulating 40–100 psig Vault		938	876	scf/station-yr	1996 EPA/GRI
	Regulating <40 (both)		938	876	scf/station-yr	1996 EPA/GRI

[1]In Massachusetts, a category of “other” mains was listed in the data set indicating materials other than those identified. “Other” mains used the same emissions factor as unprotected steel mains.
[2]In Massachusetts, a category of “other” services was listed in the data set indicating materials other than those identified. “Other services” used the same emissions factor as unprotected steel services.
psig = pounds per square inch, gage
[3]M&R – Metering and Regulating

- **Pipeline Blowdowns:** The only report to address this source was the 1996 EPA/GRI study.
- **Pipeline Dig-Ins:** The only report to address this source was the 1996 EPA/GRI study.
- **PRVs:** The only report to address this source was the 1996 EPA/GRI study.
- **Cast Iron Mains:** Data from 1996 EPA/GRI study and the Comgás study were combined to create a new emissions factor. The 912 data points from the Comgás study were combined with the 21 data points from the 1996 EPA/GRI study.
- **Cast Iron Mains – Plastic Lined:** The emissions factor used for this source was the same as the plastic mains emissions factor.
- **Plastic Mains:** The emissions factor from the ICF Report was used because the 1996 EPA/GRI emissions factor is no longer representative of the actual leak rates.

- **Protected Steel Mains:** The only report to address this source was the 1996 EPA/GRI study.
- **Unprotected Steel Mains:** The only report to address this source was the 1996 EPA/GRI study.
- **Services (Copper, Plastic, Protected Steel, and Unprotected Steel):** The only report to address these sources was the 1996 EPA/GRI study.
- **Residential Meters:** Both the 1996 EPA/GRI study and the GTI/AGA report contain emissions factors for residential meters. The data from the 1,472 meters screened in the 1996 EPA/GRI study and the 2,400 meters screened in the GTI/AGA report were combined to create a new emissions factor.
- **Commercial Meters:** Both the 1996 EPA/GRI study and the GTI/AGA report contain emissions factors for commercial meters. The 1996 EPA/GRI study combined emissions from commercial and industrial meters. The resulting emissions factor, however, was extremely close in magnitude to the calculated emissions factor from the GTI/AGA report. Therefore, the majority of the tested meters were assumed commercial meters. The data from the 149 meters screened in the 1996 EPA/GRI study and the 863 meters screened in the GTI/AGA report were combined to create a new emissions factor.
- **Industrial Meters:** Both the 1996 EPA/GRI study and the GTI/AGA report contain emissions factors for industrial meters. The 1996 EPA/GRI study, however, combined data from commercial and industrial meters. The emissions factor from this study was substantially lower than the emissions factor from the GTI/AGA study. Therefore, the majority of the tested meters were assumed commercial meters, not industrial meters. Because of this, the emissions factor from the GTI/AGA report was used as is.
- **Metering and Regulating Stations:** Both the GTI/AGA report and the 1996 EPA/GRI study contain emissions factors for the different types of stations. In the 1996 EPA/GRI study, the stations are broken out by pressure group and location (aboveground and vaults). In the GTI/AGA report, the stations are broken out by type (custody transfer, pressure regulating, and district regulating). Because fugitive emissions rates are correlated with station pressure, the 1996 EPA/GRI emissions factors were used in this analysis.

3.1.2.2. Activity Factors

Activity factors are a count of the actual number of emissions sources within a source type category. Activity factors were provided by both companies. These included the miles of mains by type, the count of services by type, the count of meters by type, the count of gate stations, and the count of regulating stations. For all vented emissions sources, the total miles of mains are the activity factor. For each fugitive emissions source, the corresponding miles of main or component counts are the activity factors (e.g., the miles of cast iron mains are the activity factor for cast iron main fugitive emissions and the count of industrial meters is the activity factor for industrial meter fugitive emissions). The counts of residential meters, commercial meters, and industrial meters were provided by Companies A and B. Company B provided the counts directly, while Company A provided the counts of residential directly and estimated the commercial and industrial. Company A defined the non-residential meters with annual use greater than 250,000 therms as industrial and the remaining as commercial.

Companies A and B provided the count of gate stations, which were classified as “metering and regulations” (M&R) stations (from Table 3-3). For Divisions 2 and 3, all gate stations were assumed to be metering and regulating stations with greater than 300 pounds per square inch, gage (psig) incoming pressure. For Division 1, two of the gate stations had greater than 300 psig, and one was between 100 and 300 psig. These assumptions were based either on a schematic (Division 1) or pressure readings for gate stations (Divisions 2 and 3). The companies also provided the count of district regulators, which were classified as “Regulating” stations. In Division 1, no main line pressure after the gate station was above 300 psig. No specific pressures were assigned to each district regulator, however, nor were all regulators shown on the provided schematic. Therefore, we assumed an even distribution between regulating stations with 100–300 psig, 40–100 psig, and below 40 psig. Division 3 provided inlet and outlet pressure readings for all of their district regulators. Division 2 provided pressure readings for 90 percent of their district regulating stations, and the remaining 10 percent were scaled linearly.

Some mains were not classified as one of the types listed in Table 3-3. For these "other" types of mains, no emissions factor exists. Therefore, for emissions-estimating purposes, these mains were grouped with the unprotected steel mains.

3.1.3. Statewide Analysis

It is possible from the analysis and available data to scale up from the three service territories to develop a rough statewide estimate of lost gas and methane emissions. It is not possible to estimate LAUF for all Massachusetts by scaling up existing data because LAUF depends on company-specific information including company use of gas, theft and dig-ins, line pack, soft closures and accounting practices for billing lag, which were not available. The bottom-up analysis methodology was used to evaluate Massachusetts' lost gas and methane emissions from all LDCs. The activity data for the state were provided by the DPU, PHMSA, and EIA. The emissions factors used were the same as outlined in the Section 3.1.2.1.

3.1.3.1. Activity Factors

The activity factor type for each emissions source is the same as those listed in the bottom-up analysis. The DPU provided the miles of mains by type. Data for the count of services by type was acquired from the PHMSA.[27] Residential meters, commercial meters, and industrial meters were estimated by customer type as reported in the EIA.[28] Each customer was assumed to have one meter.

The number of metering and regulating stations by pressure grouping was estimated by scaling the counts of the three divisions' metering and regulating stations by pressure grouping with total consumption in the state of Massachusetts. This was done using the following equation:

$$R_{Mi} = \frac{C_M}{\sum_{d=1}^{3} D_d} * \sum_{d=1}^{3} R_{d,i}$$

Where:

R_{Mi}	=	Count of Massachusetts metering and regulating stations of pressure group i
i	=	Pressure group of metering and regulating stations
C_M	=	Consumption of gas in Massachusetts in 2012 as stated by the EIA[29] (scf)
D	=	Deliveries of gas from Division d
d	=	Division 1, 2, or 3 corresponding to the divisions in the top-down and bottom-up analysis

[27] Pipeline and Hazardous Material Safety Administration. Distribution, Transmission & Gathering, LNG, and Liquid Annual Data. Retrieved from: http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

[28] U.S. Energy Information Administration. Number of Natural Gas Consumers. Retrieved from: http://www.eia.gov/dnav/ng/ng_cons_num_dcu_sma_a.htm

[29] U.S. Energy Information Administration. Natural Gas Consumption by End Use. Retrieved from: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SMA_a.htm

R = Count of metering and regulating stations at Division d of pressure group i

3.1.3.2. Emissions Factors

The emissions factors are the same as the emissions factors from the bottom-up analysis outlined in Section 3.1.2.1.

3.2. Results of Top-down Analysis

ICF used data from the companies' divisions to evaluate the receipts, deliveries, and adjustments to these values as stated in the methodology section. The summary of these results is shown in Table 3-4.

Table 3-4: Top-down Analysis Summary

Receipts/ Deliveries	Category	Division 1 Gas (Mcf)	Division 2 Gas (Mcf)	Division 3 Gas (Mcf)
Receipts	Gate Station Receipts	9,208,571	6,322,210	10,656,695
	Adjustments for Non-Metered Gas Received	N/A	2,833	N/A
Receipts	***Total Receipts***	***9,208,571***	***6,325,044***	***10,656,695***
Deliveries	Customer Use	8,900,635	6,290,922	10,514,057
	Company (Own) Use	96,187	7,518	25,033
	Storage/Withdrawal Adjustments	N/A	N/A	N/A
	Soft Closes	464	ND	ND
	Theft	1,138	ND	ND
	Line Pack Changes	401	17	71
	Intentional Venting	420	10	24
	Dig-Ins/Mishaps	19	ND	ND
	Meter Bias	−35,603	31,274	52,268
	Billing Cycle Adjustments	4,789	813	36,053
	Composition Corrections	0	0	0
	Adjustments for Non-Metered Gas Delivered	N/A	4,604	N/A
Deliveries	***Total Deliveries/Send Outs***	**8,968,451**	***6,335,157***	***10,627,506***
Fugitive Emissions plus Uncertainty		***240,119***	***−10,113***	***29,189***
Percentage of Receipts		*2.6%*	*-0.2%*	*0.3%*

ND – Company did not have data to estimate this value.
N/A – Value is not applicable to this analysis.

As expected, billed customer use accounts for most gas entering the system, ranging from 96.1 percent to 99.5 percent. Company (own) use ranged from 0.1 percent to 1 percent of total gas entering the system. Theft and soft closes were small sources accounting for less than one-tenth of a percent, and line pack changes, intentional venting, and dig-ins and mishaps accounted for a significantly smaller portion of gas on average. Company B did not estimate gas from theft or mishaps/dig-ins and so these values were not taken into consideration in the analysis for these two divisions.

Overall, the Division 1 analysis indicates a cumulative uncertainty plus a fugitive estimate of 2.6 percent of receipt. The Division 2 analysis shows a −0.2-percent estimate which is, from a practical perspective, not possible. The negative value is a result of incomplete or inaccurate accounting of the LAUF components (see discussion on uncertainty of each element in Sections 3.1.1.1 and 3.1.1.2) and illustrates the significance of the uncertainty factor in the LAUF estimate. Finally, the Division 3 analysis shows a 0.3-percent estimate for fugitive emissions plus uncertainty. One factor that could contribute to this low result is that Division 3 has no cast iron mains in its system, which reduces fugitive emissions.

Additional charts detailing the breakdown of sources are located in Appendix A.

3.3. Results of Bottom-up Analysis

Under the bottom-up analysis, Divisions 1, 2, and 3 had 1.8 percent, 1.6 percent, and 0.6 percent of receipts leave the system, respectively, through unintentional or intentional gas releases. These releases can then either become atmospheric emissions or be absorbed in the ground through soil oxidation. In both scenarios, the gas has left the pipeline and is lost gas, though not necessarily resulting in methane emissions to the atmosphere. The estimated gas leaving the pipeline is broken out further in Table 3-5. Additional figures are located in Appendix A.

Table 3-5: Bottom-up Analysis Lost Gas Breakdown

Source	Type	Division 1 Lost Gas (Mcf)	Division 2 Lost Gas (Mcf)	Division 3 Lost Gas (Mcf)
Pipeline Blowdowns	Vented	66	94	267
PRVs		33	46	131
Pipeline Dig-Ins		1,034	1,469	4,163
Customer Meters – Residential	Fugitive	3,960	7,548	3,189
Customer Meters – Commercial		1,572	1,705	818
Customer Meters – Industrial		5,014	0	0
M&R Stations (All)		4,494	7,352	10,261
Mains – Cast Iron		129,999	66,854	0
Mains – Cast Iron Plastic Lined		0	0	0
Mains – Plastic		2,264	4,002	15,184
Mains – Protected Steel		551	1,141	2,443
Mains – Unprotected Steel		5,033	2,289	14,487
Services – Copper		151	0	0
Services – Plastic		230	329	863
Services – Protected Steel		936	921	3,816
Services – Unprotected Steel		10,066	9,041	8,347
Subtotals (by type)	*Fugitive*	*164,270*	*101,182*	*59,410*
	Vented	*1,132*	*1,609*	*4,560*
TOTAL		***165,402***	***102,791***	***63,970***
Percentage of Receipts		*1.8%*	*1.6%*	*0.6%*

As shown in Table 3-5, gas leaves the LDC systems primarily from mains—mostly cast iron and unprotected steel—followed by releases from unprotected steel services. In Division 3 where there are no cast iron mains the larger number of high pressure regulating stations results in a higher percentage of lost gas from metering and regulating stations. The Division 1 lost gas estimate of 1.8 percent corresponds to the 2.6 percent fugitives plus an uncertainty estimate from the top-down analysis (because venting emissions are estimated to be insignificant in both analyses). For Divisions 2 and 3, however, the lost gas estimates do not correspond well to the top-down analysis estimate of −0.2 percent and 0.3 percent, respectively. This result could be due to the uncertainties in characterization of LAUF components in the top-down analysis or truly low emissions in the system (e.g., Division

3, which has no cast iron mains). Either way, this comparison illustrates the value of conducting both the top-down and bottom-up analyses together to validate the estimates. ICF did not attempt to reconcile the two analyses due to limitations on data availability.

After accounting for the soil oxidation factors from the sources underground (mains and services) and the percentage of non-methane gases in natural gas, the remainder escapes to the atmosphere as methane emissions. These methane emissions follow the same pattern as the LAUF values, with cast iron and unprotected steel mains accounting for the majority of methane emissions. These values are outlined below in Table 3-6.

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Table 3-6: Bottom-up Analysis Methane Emissions Breakdown

Source	Type	Division 1 Methane Emissions (Mcf)	Division 2 Methane Emissions (Mcf)	Division 3 Methane Emissions (Mcf)
Pipeline Blowdowns	Vented	62	88	249
PRVs		30	43	122
Pipeline Dig-Ins		965	1,372	3,888
Customer Meters – Residential	Fugitive	3,699	7,049	2,979
Customer Meters – Commercial		1,468	1,593	764
Customer Meters – Industrial		4,683	0	0
M&R Stations (All)		4,198	6,867	9,583
Mains – Cast Iron		72,487	37,278	0
Mains – Cast Iron Plastic Lined		0	0	0
Mains – Plastic		2,073	3,663	13,899
Mains – Protected Steel		499	1,034	2,214
Mains – Unprotected Steel		4,617	2,099	13,288
Services – Copper		141	0	0
Services – Plastic		169	242	635
Services – Protected Steel		851	838	3,471
Services – Unprotected Steel		9,298	8,351	7,711
Subtotals (by type)	*Fugitive*	104,182	69,015	54,543
	Vented	1,058	1,503	4,259
TOTAL		***105,240***	***70,518***	***58,803***
Percentage of Receipts		*1.1%*	*1.1%*	*0.6%*

From the bottom-up analysis, leaks from mains are estimated to be the largest source of methane emissions. In Divisions 1 and 2, cast iron mains account for 69 percent and 53 percent of methane emissions, respectively, and all mains account for 76 percent and 63 percent of methane emissions, respectively. In Division 3, where no cast iron mains are present, mains still account for 50 percent of estimated methane emissions, but the larger number of high pressure regulating stations result in a greater percentage of methane emissions from metering and regulating stations.

Furthermore, the throughput is also a contributing factor to methane emissions, because additional infrastructure is necessary to move more gas. Higher throughput, however, does not necessarily correlate with higher emissions. Divisions 1 and 2 both have cast iron mains and the emissions of Division 1 are higher than those of Division 2, corresponding to the amount of throughput. Division 3, however, has the highest throughput of all the divisions, but the lowest estimated emissions because it has less leak-prone infrastructure (cast iron and unprotected steel mains). The division throughput and results of the bottom-up analysis are listed in Table 3-7.

Table 3-7: Overall Bottom-up Analysis Results

Division	Lost Gas (Mcf)	Methane Emissions (Mcf)	Receipts (Mcf)
Division 1	165,402	105,240	9,208,571
Division 2	102,791	70,518	6,325,044
Division 3	63,970	58,803	10,656,695

3.4. Results of the Statewide Analysis

Extrapolating LAUF values to the entire state based on the LAUF values for the two companies (with three service territories) was not possible because LAUF depends on company-specific information regarding company use of gas, theft and dig ins, line pack, soft closures, and accounting practices for billing lag. Estimating these values for the companies would introduce a large amount of uncertainty in the statewide LAUF estimate. By contrast, *ICF did estimate lost gas and methane emissions for all LDCs in Massachusetts* using the bottom-up methodology described in Section 3.1.3, and the results are shown in Table 3-8. A rough extrapolation to the entire state for lost gas and methane emissions yields 7.0 billion standard cubic feet and 5.4 billion standard cubic feet, respectively. The values are presented as volumes (in thousand cubic feet or Mcf). Converting the volumes to percentages of state totals would result in a high degree of uncertainty because extrapolating the volumes from the available data is imprecise, and ICF has limited confidence in the available estimates of the total statewide volume of gas received. The methane emissions are the lost gas estimates adjusted for soil oxidation and the concentration of methane in natural gas.

As expected, the three largest sources of lost gas and methane emissions are cast iron mains, industrial meters, and unprotected steel services. These three sources account for 84 percent of lost gas and 82 percent of methane emissions in the state. Vented emissions account for a very small portion of emissions: approximately 0.6 percent of lost gas and 0.7 percent of methane emissions.

Table 3-8: Bottom-up Analysis – Massachusetts

Source	Type	Massachusetts	
		Lost Gas (Mcf)	Methane Emissions (Mcf)
Pipeline Blowdowns	Vented	2,335	2,181
PRVs		1,144	1,069
Pipeline Dig-Ins		36,393	33,991
Customer Meters – Residential	Fugitive	132,131	123,410
Customer Meters – Commercial		66,853	62,441
Customer Meters – Industrial		2,362,953	2,206,998
M&R Stations (All)		354,877	331,455
Mains – Cast Iron		2,935,697	1,636,939
Mains – Cast Iron Plastic Lined		0	0
Mains – Plastic		86,193	78,894
Mains – Protected Steel		19,974	18,096
Mains – Unprotected Steel		322,806	296,074
Services – Copper		3,047	2,846

Source	Type	Massachusetts	
		Lost Gas (Mcf)	Methane Emissions (Mcf)
Services – Plastic		7,385	5,435
Services – Protected Steel		30,670	27,901
Services – Unprotected Steel		638,110	589,439
Subtotals (by type)	*Fugitive*	*6,960,696*	*5,379,928*
	Vented	*39,872*	*37,240*
TOTAL		***7,000,569***	***5,417,170***

ICF compared the estimates to other publicly available estimates of methane emissions for Massachusetts. Table 3-9 shows a summary of various agencies' figures for methane emissions in Massachusetts. The table presents the methane emissions in metric tons (MT), the customary unit for reporting greenhouse gases.

Table 3-9: Massachusetts Methane Emissions Estimates

Source	Methane Emissions[1] (MT methane)	Considerations[2]
MassDEP Inventory (2012) – Distribution	64,754	Includes all LDCs High-level estimate of all emissions sources
MassDEP GHG Reporting Program (2012)	35,207	Reporting threshold 5,000 tons/year CO_2e Includes 8 LDCs, high-level estimate
EPA GHGRP Subpart W Reporting – Distribution, Massachusetts (2012)	27,963	Reporting threshold 25,000 tons/year CO_2e Only includes 5 LDC reporters
EIA (2012)	31,740	Pipeline/service losses are reported to EIA and comprise 14% of reported LAUF in Massachusetts
ICF Bottom-up Estimate	104,335	Includes all LDCs

[1]MT = metric tons; one metric ton equals 1,000 kilograms or 2,204.6 pounds. It is a common unit for reporting greenhouse gases.
[2]CO_2e = carbon dioxide equivalent

ICF's bottom-up estimate of methane emissions from the gas distribution systems in Massachusetts yields a result that is greater than the MassDEP Inventory emissions estimate. The difference between the estimates is due to two factors. First, the MassDEP Inventory is a very high-level estimate of emissions. It uses only the number of miles of mains and total number of services as activity factors. The ICF estimate calculates methane emissions from more sources, including vented emissions and commercial meters. Second, the MassDEP Inventory uses simplified emissions factors based on the EPA's Greenhouse Gas Inventory (based on the 1996 EPA/GRI Report), which may not reflect the most current understanding of emissions factors or Massachusetts-specific conditions. ICF used modified emissions factors as discussed in Section 3.1.2.1.

ICF's bottom-up methane emissions estimate is also greater than the values for the MassDEP GHG Reporting Program, EPA subpart W, and EIA. These inventories do not represent all emissions sources or account for all LDCs. The MassDEP GHG Reporting Program and subpart W results do not account for all LDCs in the state, and EIA attributes only a small portion of LAUF to emissions. The EIA appears to be underestimating emissions because, when compared to other data sets (i.e., subpart W and the MassDEP Reporting Program), the EIA results have smaller emissions values but cover more companies.

3.5. Conclusions from the Top-down and the Bottom-up Analyses

This section reviews the results of the top-down and bottom-up analyses of data from the two gas distribution companies (with three service territories) studied, and of the statewide analysis. We draw conclusions about the components used in LAUF estimates; the methods for calculating LAUF, lost gas, and methane emissions; and the magnitude and significance of the values calculated.

3.5.1. Top-down Conclusions

General

- ICF identified 12 LAUF components, shown in Table 1-2 as the "adjustments." The largest components of LAUF are company use, meter bias, billing cycle adjustments, and fugitive emissions. The relative magnitudes of the components affecting LAUF from the top-down analysis for Division 1 are shown in Figure 3-2. Although these Division 1 results do not necessarily reflect the magnitude of each component of LAUF across all Massachusetts LDCs, they do illustrate the relative magnitude of the various components that might be expected.

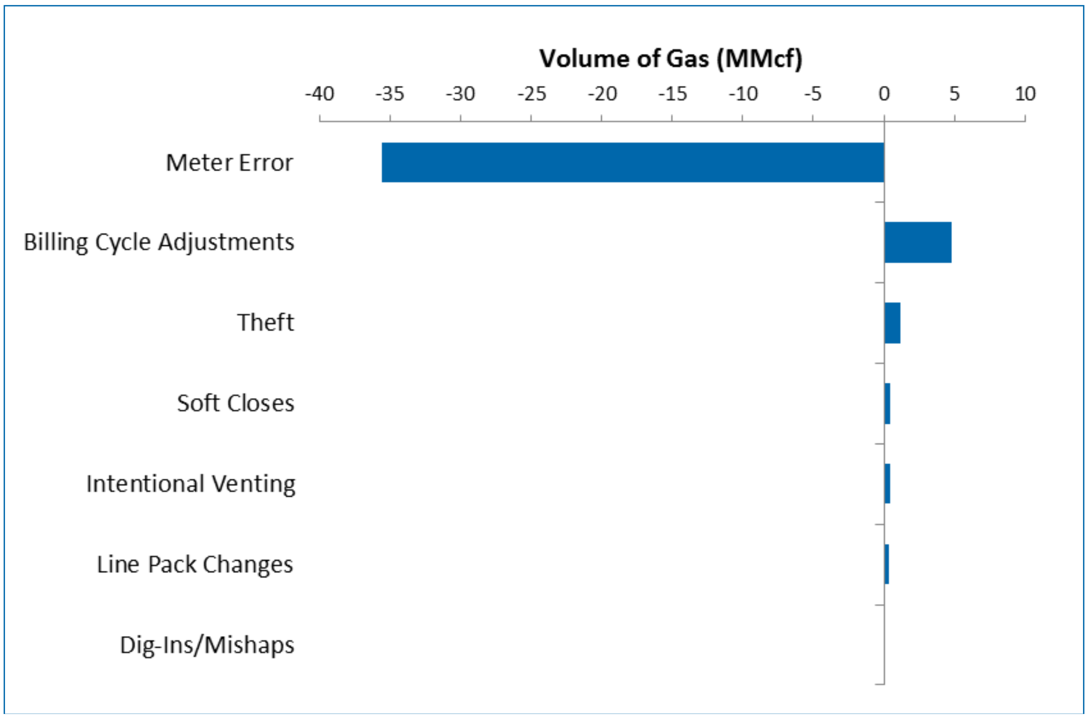


Figure 3-2: Components of Lost and Unaccounted for from Top-down Analysis for Division 1

- LAUF, as currently defined by the DPU and reported by the LDCs, is neither an accurate representation of the amount of natural gas lost from the system nor an appropriate surrogate for methane emissions.
- LAUF for the two gas distribution companies (comprising three service territories) involved in the study ranges from –0.2 to 2.6 percent.[30]

[30] Incomplete or inaccurate accounting of the LAUF components accounts for the negative value for LAUF.

- Extrapolating to the entire state from the LAUF figure for the two companies is not possible. The degree of imprecision in estimating a statewide average for many of the components of LAUF would be high because these components are a function of company-specific practices that vary widely among LDCs.

Specific Components

- Some components, such as storage, may not apply to all LDCs in Massachusetts. The amount each component contributes to total LAUF differs for each company, but this study identified some general trends presented below.
- Meter bias is a significant factor in estimating LAUF. Meter bias can be either positive or negative and may obscure the effect of other components. ICF identified inconsistencies in the meter test data that companies provided to the DPU and in the raw data the companies provided to ICF. Replacing meters with more accurate meters would reduce bias, although some meter bias is inevitable.
- Company use of gas is also a large factor in estimating LAUF. Identifying all gas uses and using meters to measure company gas eliminates some uncertainty in estimating LAUF.
- Calculating billing cycle adjustments may be more complex because coordination with accounting divisions is necessary.
- During December and January, daily customer gas use is highly variable due to temperature fluctuations. Gas usage does not vary significantly in June and July. Our analysis indicates that using July 1 to June 30 as the LAUF reporting year minimizes the variability in the billed volumes.
- Theft and soft closes were small components of LAUF, accounting for less than one-tenth of a percent, and line pack changes, intentional venting, and dig-ins and mishaps accounted for a significantly smaller portion of LAUF.

Calculations and Uncertainty

- LDCs do not currently collect the data necessary to support calculations of each component of LAUF. Data to support calculation of dig-ins, soft closes, and intentional venting during line repair and replacement are not consistently captured or reported. Some components (including theft and dig-ins) have a large error component.
- Although compositional corrections[31] were not a factor in any service area analyzed, such corrections can be a small source of error and uncertainty in LAUF calculations. Compositional errors can be avoided by using the metered receipt and delivery volumes instead of therms.
- This study evaluated three service areas with relatively simple supply and delivery systems. Other systems in Massachusetts may have interconnections with other adjacent service territories. Interconnect deliveries are generally not metered, which complicates the calculation of the amount of gas received—a key factor in LAUF analysis. Interconnects may not, however, be an issue when evaluating LAUF for the entire system because any transported gas is likely metered.
- The top-down approach for calculating LAUF is not intended to provide lost gas or methane emissions estimates. The approach provides an estimate of the expected magnitude of lost gas and methane emissions using a process of elimination. It also includes uncertainties in the estimation of some LAUF components. Differences between top-down and bottom-up estimates can be used to evaluate the accuracy of and uncertainty in lost gas and methane emissions estimates.

[31] If gas use is measured on a heat content basis (therms or BTU), a small error in converting the heat content to a volumetric basis can occur, usually attributed to rounding or averaging in the conversion factors. Compositional correction accounts for this error.

Ratepayer Implications

- Meter bias (specifically fast meters) can result in customers having to pay for more gas than they actually use. Quantifying and reporting the effects of meter bias and other significant contributors to LAUF will provide a more transparent understanding of the gas cost components and identify specific areas for reducing LAUF.
- Customers pay for LAUF through the utility's recovery of purchased gas costs. Lower LAUF should be beneficial to ratepayers.

3.5.2. Bottom-up Conclusions

- Methane emissions for the two gas distribution companies (comprising three service territories) involved in the study ranges from 0.6 to 1.1 percent of total gas received. Lost gas ranges from 0.6 to 1.8 percent of total gas received.
- A rough extrapolation to the entire state for lost gas and methane emissions yields 7.0 billion standard cubic feet and 5.4 billion standard cubic feet, respectively. Converting these numbers to percentages would result in a high degree of uncertainty, however, both because of the imprecision in extrapolating the numbers and the limited confidence in the total statewide volume of gas received.
- The effectiveness of replacing cast iron and unprotected steel with plastic pipe to reduce emissions is clearly demonstrated in this study, as shown by the emissions estimates for Division 3.
- The accuracy of bottom-up methane emissions estimates is directly related to the accuracy and representativeness of emissions factors used. Currently available emissions factors have significant uncertainty.
- The analysis of lost gas in this report includes the entire volume of natural gas, which is not adjusted for methane content. The typical methane content of natural gas that is of pipeline quality is 93.6 percent.[32]
- Methane emissions estimates for climate change analysis should account for gas that is degraded by chemical and biological activity during movement from the pipe to the surface, using the soil oxidation factor. The soil oxidation factor used for cast iron pipes is considerably larger than that for steel and plastic mains and has a large effect on the emissions estimates for systems with a high percentage of cast iron mains. Limited technical data are available to support the soil oxidation factors, specifically for cast iron pipes**.**

[32] 93.6% methane is the value used by EPA in the GHG Inventory and is derived from the 1996 EPA/GRI report Volume 6, Appendix A, Table A-1. Pipeline quality gas in Massachusetts may be different.

4. Recommendations

4.1. Consistency, Accuracy, and Transparency of LAUF Reporting to Massachusetts DPU

4.1.1. Using LAUF for Analysis

DPU should not use LAUF, as currently defined in Massachusetts, to draw conclusions on the efficiency of natural gas distribution systems.

LAUF values that LDCs currently report are calculated using definitions established by the DPU, as shown in Table 1-1. Item 72 in the Annual Return calculates the "unaccounted for gas" (LAUF) by subtracting the amount of gas sold to customers and the amount the LDC uses from the total amount of gas received and transported. The DPU's current Service Quality Guidelines define unaccounted for gas (i.e., LAUF) as the reduction in the quantity of natural gas flowing through a pipeline that results from leaks, venting, and other physical and operational circumstances on a pipeline system. The new Service Quality Guidelines, proposed in July 2014, define LAUF as the differential between the amount of gas that enters the Company's city-gates and the amount of gas billed to customers, expressed as a percentage of the amount of gas that entered the Company's city-gates. All three definitions report LAUF as a single aggregate value and require no further breakdown of LAUF components.

LAUF values that apply the current definitions should not be used to draw conclusions about the efficiency of natural gas distribution systems for two reasons. First, when LAUF is presented as a single value, all components that comprise LAUF are combined and components with negative values, such as meter bias, can offset components with positive values. The result may be an aggregate value that appears reasonable, but in fact has large positive values for some components that are offset by large negative values for other components. The high and low values may indicate problematic operational conditions such as excessive emissions, meter bias, or theft that are obscured by averaging all LAUF components to derive a single value. Second, the current definitions do not provide a uniform set of LAUF components to be included in the LAUF calculation, and do not define methods to quantify each component. Under the current definitions, LDCs may account for none, some, or all components, and may choose how they calculate the component values. Values of LAUF cannot be compared among LDCs because of the inconsistency in how they are calculated. In addition, apparent trends in LAUF over time may be misleading because LDCs can change their calculation methods.

4.1.2. Improved Reporting Mechanism for LAUF

The DPU should develop a reporting mechanism that would require improved reporting of LAUF and lost gas. One option is to require more detailed reporting of LAUF as part of the Service Quality (SQ) Guidelines.

All local distribution companies in Massachusetts calculate and report their LAUF values according to the DPU Annual Return (Item 72) standard, which is based on a 1961 regulation. Unfortunately, this mechanism does not provide a methodology for consistently calculating LAUF. LAUF is also included in the SQ Guidelines, which applies a simplistic and incomplete definition for LAUF. Because of such inconsistent reporting among utilities, interpreting the reported LAUF values is difficult.

ICF recommends that the DPU develop a detailed calculation and reporting mechanism that can be followed consistently by all utilities in the state for annual LAUF reporting. Consistent reporting will allow for a meaningful comparison among companies and tracking of LAUF values over time. The DPU is currently considering revisions to SQ Guidelines (Order D.P.U. 12-120-B, July 11, 2014). ICF believes the SQ Guidelines are an appropriate mechanism for LAUF reporting requirements because it builds on an existing LAUF reporting requirement. Using the revised SQ report as a reporting mechanism enables the DPU to develop and implement a new framework for reporting as described in the next recommendation.

Considerations for implementation – SQ reporting applies only to investor-owned utilities; municipal utilities will not be subject to the same level of reporting requirements.

4.1.3. Standardization and Quantification of LAUF Reporting Requirements

The DPU should ensure that LAUF estimates that LDCs provide include each component that contributes significantly to the total. The larger components should be quantified accurately while smaller components can use simplified quantification methods or be consolidated. Calculation and reporting of LAUF should be standardized.

To ensure consistency in LAUF reporting, ICF recommends that LDCs provide LAUF estimates that include each component that adds significantly to the total. ICF recognizes that certain components (e.g., meter bias) might have a larger numerical influence on LAUF than smaller components, such as pipeline venting. Accounting for the individual components also provides increased transparency that will promote meaningful efforts to reduce LAUF and methane emissions over time. Therefore, we recommend that the larger components be quantified accurately while smaller components can use simplified quantification methods (or be consolidated) for quantification and reporting. The reporting should follow a specific framework for calculation and reporting and consider the following issues.

Definitions. Components of LAUF and terms used in the calculations and corrections should be defined so that LDCs report a uniform set of components and use consistent data in their calculations and reporting.

Data management and flow. LDCs process raw data captured from meter readings and other data sources before they use the numbers in LAUF calculations. The framework should provide guidance on data that are acceptable for use in the calculations and reporting. For example, estimating theft might be acceptable, but estimating the number of pipeline miles or type might not be.

Calculation methodology. The framework should establish detailed methods to estimate the value of all known components that contribute significantly to LAUF. At a minimum, these components should include company use of gas, lost gas, meter error, billing cycle adjustments, theft, and soft closes.

Uncertainties. Clear guidelines should be provided for identifying and reporting uncertainties in the data and calculations.

Reporting requirements. The framework should list specific data reporting elements such that the LAUF values and calculations are transparent and consistent.

Considerations for implementation – Large LDCs already have the necessary data and resources to calculate individual components that influence LAUF. Smaller LDCs, however, could struggle to comply with similar requirements, which might warrant a different approach to LAUF reporting, depending on the size of the utility.

4.1.4. Consistent Understanding of LAUF, Lost Gas, and Methane Emissions

The DPU should build awareness of the differences between LAUF, lost gas, and methane emissions through DPU fact sheets and updated definitions in regulations/guidance.

What constitutes LAUF is subject to considerable misunderstanding. Several reports and regulations confuse LAUF with methane emissions or lost gas. In addition, components of LAUF such as meter bias have not received attention in understanding and evaluating potential improvements to LAUF.

ICF recommends that the DPU develop fact sheets explaining the concept of LAUF and defining the components that influence LAUF and how they differ from one another. The fact sheet should describe the differences between LAUF, lost gas, and methane emissions. ICF has developed an example fact sheet and provided it in Appendix C.

Considerations for implementation – Each agency might need a dedicated fact sheet tailored to its needs. For example, the MassDEP's focus on LAUF is principally from the methane emissions perspective. The DPU might use LAUF for SQ purposes or for tracking reductions in methane emissions. Various stakeholders (e.g., utilities, the legislature, environmental groups, and the public) might require several types of fact sheets, each customized to their needs.

4.2. Lost Gas and Methane Emissions Reporting

4.2.1. Using Emissions Factors in LAUF Estimates

The DPU should ensure that LDCs do not include soil oxidation factors in emissions factors when used for LAUF calculations, and do include soil oxidation factors in emissions factors when estimating methane emissions from pipelines. These corrections should be applied only for methane emissions estimates.

The emissions factors for methane emissions from underground gas distribution pipelines available in the EPA/Gas Research Institute study, *Methane Emissions from the Natural Gas Industry*, include a soil oxidation factor that assumes a certain portion of natural gas emitted from the pipeline is oxidized in the soil and is never emitted to the atmosphere. These oxidation factors should not be used to calculate lost gas in LAUF, however, because LAUF represents the gas lost from the system, which differs from the amount of methane emitted to the atmosphere.

Methane is the only component of natural gas addressed in GHG estimates from gas distribution systems. Because methane does not account for 100 percent of the natural gas emitted, methane emissions estimates should be adjusted to account for methane only. Lost gas calculations used in LAUF estimates should account for all of the gas not just methane. Because lost gas is not adjusted for soil oxidation and the methane content of natural gas, the amount of lost gas is always larger than the amount of methane emissions.

ICF cautions against using soil oxidation factors and methane corrections for calculating lost gas in LAUF calculations and instead using those factors only for calculating methane emissions to the atmosphere. Definitions of LAUF, methane emissions, and lost gas should specifically reference this issue and incorporate the appropriate factors. The DPU should ensure that estimates of lost gas provided by LDCs in DPU proceedings and reports do not include reductions for soil oxidation and methane content.

Considerations for implementation – The DPU should work with MassDEP and other agencies to improve guidance on the methods and factors used to estimate methane emissions to the atmosphere.

4.2.2. Potential to Improve Pipeline Emissions Factors

The DPU should work with operators to develop a testing program to pressure test a representative amount of pipeline being replaced, where operationally feasible. The results of such tests, in addition to new data from measurement studies, can provide better emissions factors for estimating methane emissions from pipelines. The DPU should share this information with MassDEP to improve methane emissions calculation methods.

Cast iron pipelines have been identified as a major source of methane emissions from gas distribution systems, and the emissions factors used to estimate methane emissions are suspect and currently under review. Unprotected steel pipes are another large source of methane emissions and may leak at higher rates than the emissions factors reflected in the EPA/GRI report. Improving the emissions factors for these two emissions sources would substantially increase the accuracy of methane emissions estimates for LDCs. LDCs in Massachusetts have an aggressive program to replace aging cast iron and unprotected steel pipelines with plastic pipe. This program provides an opportunity for LDCs to gather data on leakage from leak-prone pipelines.

ICF recommends encouraging LDCs to pressure test some of the pipelines being replaced. This recommendation is applicable principally to cast iron pipe mains, but can be extended to unprotected steel pipe mains. A pressure test could be performed using one of two methods. In the first method, the pipe is pressurized with air to a known pressure and the drop in pressure is monitored over time to determine the leak rate. The second method involves keeping the pipeline pressurized with air at a certain pressure; the leak rate is determined by the amount of replacement air necessary to keep the pipe under constant pressure. ICF has determined this approach is a practical and proven option, as it has been previously tested by Comgás of São Paulo, Brazil. The pressure test can be conducted immediately after the old main is removed from service, before it is abandoned and sealed.

The data made available from such pressure tests, in addition to data available from any new studies on the subject, would greatly improve the estimates of lost gas and methane emissions from gas pipelines. Sharing this information with the MassDEP would improve the estimate of methane emissions used in the Massachusetts greenhouse gas inventory.

Considerations for implementation – The DPU could include pressure testing as a part of its requirement for pipeline replacement programs in the state. Additionally, the DPU could require that only a portion of the mains be pressure tested, provided that a representative and robust data set is developed.

4.3. Methane Emissions Reductions from Natural Gas Distribution Systems

Gas system operators should implement best management practices recommended by U.S. EPA's Natural Gas STAR Program.

The Natural Gas STAR Program is a voluntary partnership that EPA manages, which encourages companies in the oil and natural gas industry to adopt cost-effective technologies and practices that reduce methane emissions. Since the program's inception in 1993, partner companies have reduced their methane emissions by more than 1.15 trillion cubic feet. The Natural Gas STAR Program currently recommends several best practices that are directly applicable to the gas distribution sector. ICF recommends the implementation of the best practices the Natural Gas STAR Program recommends.

Considerations for implementation – Because the Natural Gas STAR Program is a voluntary partnership, companies must be willing to participate. In addition, the program is built around the cost-effective recovery of methane emissions, which must be coordinated with state incentives and other policy actions.

4.3.1. Directed Inspection and Maintenance Program for Surface Facilities to Identify Significant Leaks

In Massachusetts Grade 1 leaks (hazardous) must be repaired immediately and Grade 2 leaks must be repaired within 12 months. Knowing the size of the leaks is important for determining the priority for repair. Directed inspection and maintenance (DI&M) programs involve surveying a facility for leaks using a variety of instruments, including infrared cameras, organic vapor analyzers, acoustic leak detectors, and soap bubble solutions, among others. After the leaks are located, their sizes can be measured either using specialized equipment (such as a high-flow sampler) or estimated. Repair of Grade 2 leaks can be prioritized to address the most serious leaks first.

Such programs are most useful at facilities containing many different components, such as gate stations and regulating stations. At these facilities, numerous pipes, valves, flanges, meters, pneumatic controllers, and other equipment are used primarily to monitor and control gas flow. That the size of the facility and the leak rate correspond with the upstream gas pressure is well established. Because gate stations and regulating stations are used to step gas down from high pressures (>500 psig), the leak rates at these stations can be quite high. After the leaks are repaired, follow-up surveys can be conducted to ensure that the fixes hold and to monitor any smaller leaks.

4.3.2. Reduce Distribution System Pressure to Reduce Leakage Rate

The leak rate in a system is generally correlated with the pressure of the system; higher system pressure increases the potential for higher leak rates. Therefore, one way to reduce the leak rate from pressurized systems is to reduce the internal operating pressure. Because gas demand varies at different times of the year, LDCs may be able to vary their system pressures. When demand is low, such as in the summer, the pressure often can be lowered, helping reduce the leak rates.

4.3.3. Inserting Gas Main Flexible Liners when Replacement is not Expected Soon

Although most LDCs are striving to remove their cast iron and other leak-prone mains from service, removing the mains immediately is not always feasible. When these leak-prone mains are not scheduled for immediate removal or when they cannot be removed without major disruption, inserting plastic liners may be an option. Such liners are made of a flexible thin-walled plastic that can be pulled through the pipelines from the surface. Once the liners are in position, they can be heat-treated and bonded, curing the plastic in place. Plastic piping has a much lower leak rate than cast iron and other leak-prone pipe, so installing these liners can drastically reduce methane emissions until permanent plastic mains can be installed.[33] Flexible liners are currently used to a limited extent in Massachusetts.

One consideration is that plastic liners shrink the internal diameter of the pipelines, thereby decreasing their capacity if the pipeline pressures cannot be raised. In such cases, the LDCs must ensure that capacity will remain sufficient if the liners are installed.

4.3.4. Using Hot Taps for In-service Pipeline Connections

Installing a new connection on a gas main (such as for service for a new customer) requires that an opening in the main be cut. Often, the cut is completed by isolating the section using valves or “pinching off” the pipeline and then venting the gas to the atmosphere. In addition to resulting in methane emissions, this practice also can disrupt gas service for some customers. Instead of this approach, companies can use a “hot tap” to access the operating pipeline directly, without having to disrupt service or vent any gas. A hot tap is completed by using a branch connection that contains an internal drilling machine and two valves. After the connection is attached to

[33] U.S. EPA. “Insert Gas Main Flexible Liners.” 2011. Available online at: http://epa.gov/gasstar/documents/insertgasmainflexibleliners.pdf

the outside of the main, the drill can bore into the pipe while the valves are closed, preventing the gas from escaping. Once the drilling is complete, the drill can be extracted through one of the valves, and the other valve then can be opened to permit gas to flow through the new connection.[34] Although hot tapping is not a new practice, recent design improvements have reduced the complications operators may have experienced in the past.

4.3.5. Pipeline Pump-down to Capture and Re-inject Gas during Operations

When removing a section of pipeline from service for maintenance or removal, the gas in the pipeline must be evacuated. This evacuation usually is accomplished by isolating the section of pipeline and then venting the gas to the atmosphere. One technique that can help eliminate all or some of this venting is to use a portable compressor to pump the gas in the isolated section to a section of pipe still in service. By pumping down the pressure in the out-of-service pipeline, companies can greatly reduce the amount of venting.[35] This technique, currently employed by some LDCs in Massachusetts, is most applicable to larger diameter or longer sections of mains where a significant amount of gas would be vented.

[34] U.S. EPA. "Using Hot Taps for In Service Pipeline Connections." October 2006. Available online at: http://epa.gov/gasstar/documents/ll_hottaps.pdf

[35] U.S. EPA. "Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure before Maintenance." October 2006. Available online at: http://epa.gov/gasstar/documents/ll_pipeline.pdf

Appendix A. Supplemental Figures

A.1. Top-down Analysis Lost Gas Breakdown

The top-down analysis broke out the various components where gas is used intentionally or unintentionally. As such, each division provided data on the gas used during the period July 1, 2012 to June 30, 2013 according to Section 3.1.1. These data were summarized in Figures A-1 through A-3 and are aggregated and depicted for each division in the following pie charts. The "Adjustments" slice contains several items described in detail in Section 3.2.

Figure A-1: Division 1 Top-down Source Breakout

Division 2: Total Receipts 6,325 MMcf

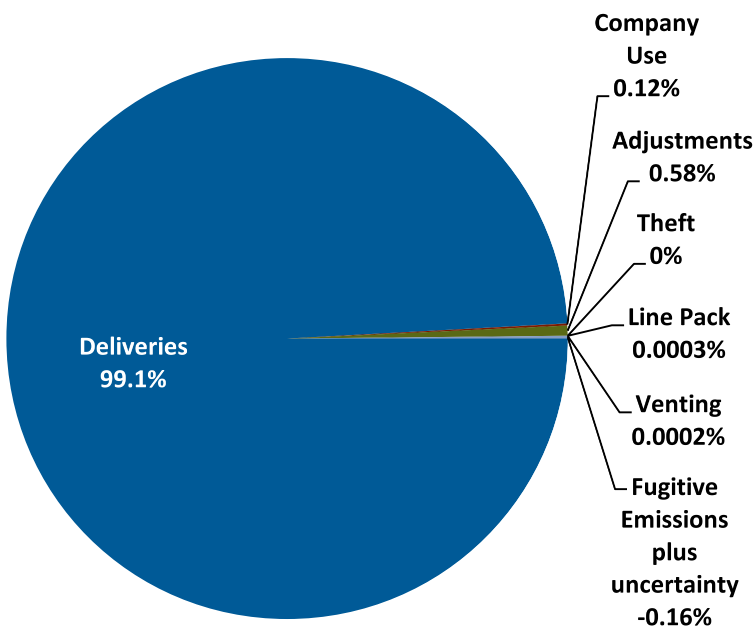


Figure A-2: Division 2 Top-down Source Breakout

Division 3: Total Receipts 10,657 MMCF

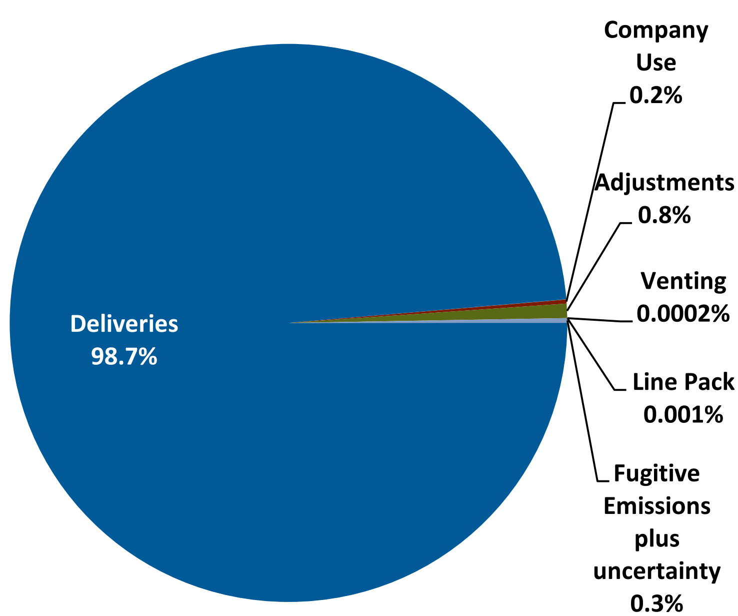


Figure A-3: Division 3 Top-down Source Breakout

A.2. Bottom-up Analysis Lost Gas Breakdown

The bottom-up analysis broke out the various components of unintentional and intentional gas lost. Each division provided activity data on the existing infrastructure according to Section 3.1.2. These data were summarized in Figures A-4 through A-6 and are aggregated and depicted for each division in the following pie charts.

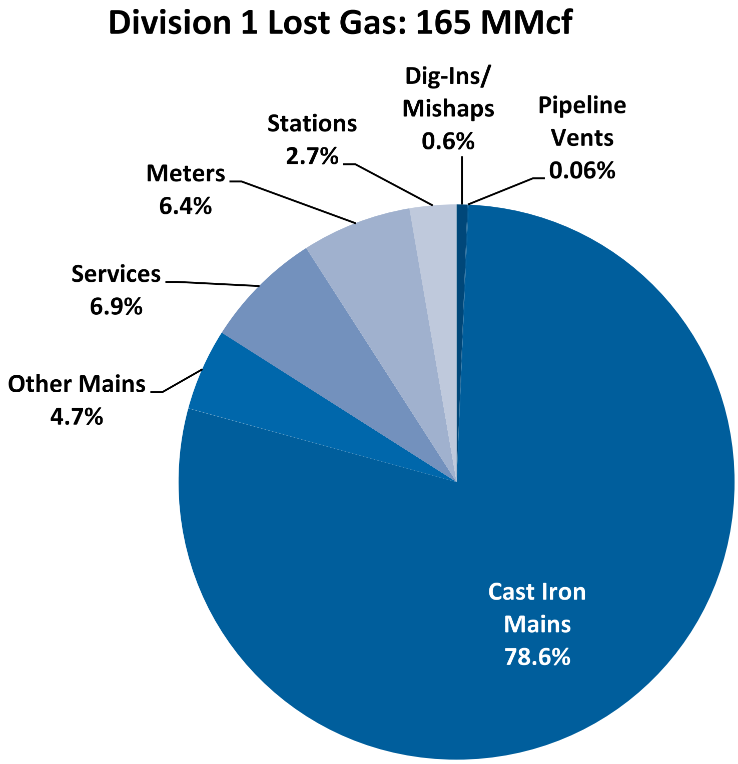


Figure A-4: Division 1 Bottom-up Lost Gas Breakout

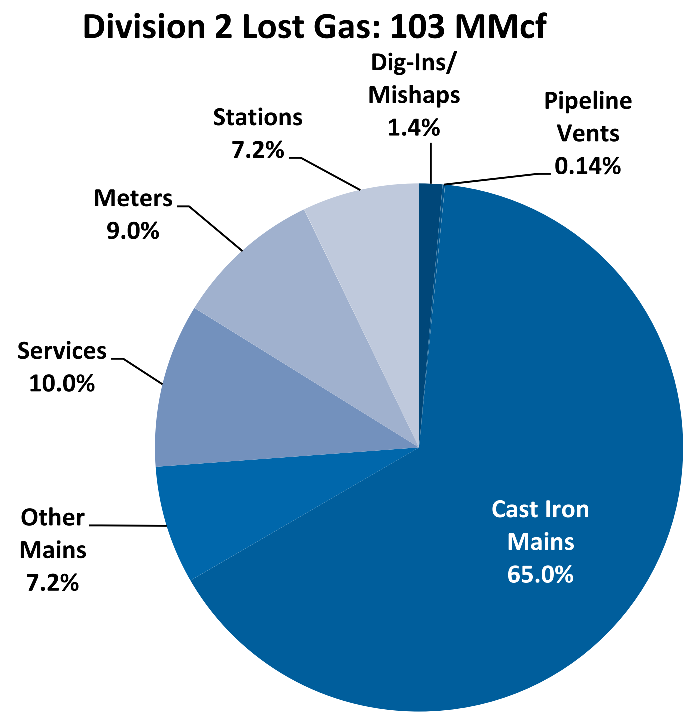


Figure A-5: Division 2 Bottom-up Lost Gas Breakout

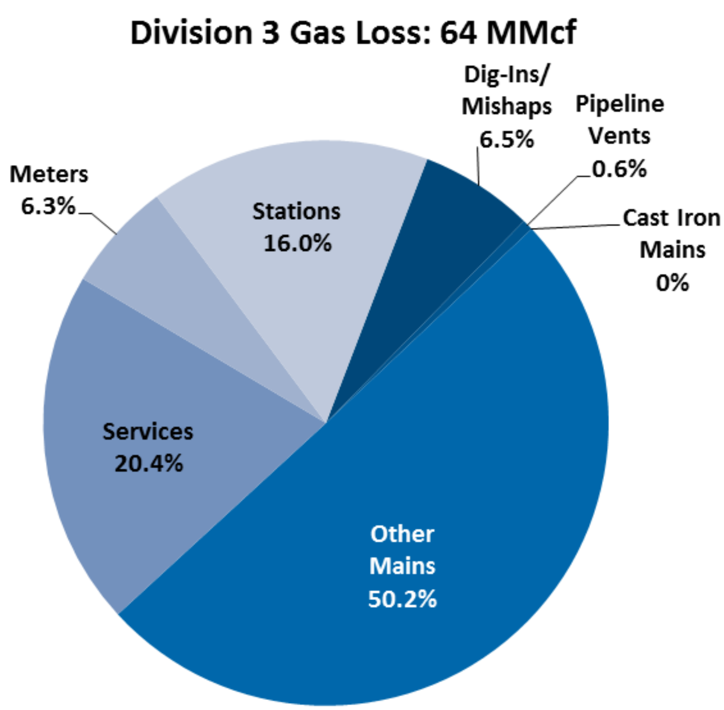


Figure A-6: Division 3 Bottom-up Lost Gas Breakout

Appendix B. Additional Information on LAUF and Emissions

B.1. Recent Articles and Studies on LAUF and Emissions

Recently, several published analyses have noted the magnitude and effects of LAUF and methane emissions from natural gas distribution systems that have gained public attention.

- The Conservation Law Foundation issued a report in November 2012[36] noting the significance of emissions from natural gas distribution pipelines and their effect on the environment and consumers. The report cited LAUF values for several utilities in Massachusetts and provided several policy options for reducing emissions from natural gas pipelines, including enhanced reporting and monitoring of LAUF and emissions.
- A report prepared for Senator Ed Markey (D-Massachusetts) in August 2013[37] by the House Natural Resources Committee Democratic staff assesses the impact of leaks and other LAUF, using Massachusetts as a case study. The report monetizes the cost of the lost gas to customers and makes several recommendations to accelerate replacement of leak-prone pipelines. One recommendation includes adopting a standard definition and methodology for calculating unaccounted for gas.
- A series of methane measurement studies has been conducted by Picarro Corp. (a manufacturer of instruments to measure methane gas) and university researchers—in Boston,[38] Washington DC[39], and other cities—to identify leaks from natural gas mains and services at driving speeds. The results from the studies in Boston and Washington were presented as maps showing the magnitude of leaks throughout the city as colored spikes. Many local and national news outlets reported the studies and displayed the maps.
- As more electrical generating units, industrial operations, and residential customers switch to natural gas as an alternative to traditional coal and oil-based fuels, several studies have questioned the environmental benefits of natural gas when lifecycle emissions are assessed. A study by researchers at Princeton University and the Environmental Defense Fund[40] concluded that shifting from coal-fired power plants to natural gas has climate benefits provided the cumulative leak rate from the production, transport, and distribution of natural gas is below 3.2 percent. The report questions the accuracy of current leakage estimates and recommends a more rigorous scientific approach to collect better emissions data.
- The National Regulatory Research Institute published a study in June 2013[41] summarizing the issues around LAUF and the difficulties in determining accurate and transparent LAUF values. State utility commissions from 41 states were surveyed for practices related to LAUF and emissions reduction. A

[36] Conservation Law Foundation, 2012. Into Thin Air. 35 p. Available at http://www.clf.org/static/natural-gas-leaks/WhitePaper_Final_lowres.pdf

[37] Markey, E. J. America pays for gas leaks: Natural gas pipeline leaks cost consumers billions; U. S. House Natural Resources Committee: Washington, DC, 2013. http://www.markey.senate.gov/documents/markey_lost_gas_report.pdf

[38] Phillips, N. G.; Ackley, R.; Crosson, E. R.; Down, A.; Hutyra, L. 549R.; Brondfield, M.; Karr, J. D.; Zhao, K.; Jackson, R. B. Mapping urban pipeline leaks: Methane leaks across Boston. Environ. Pollut. 2013, 173, 1−4.

[39] Natural Gas Pipelines Leaks Across Washington, D.C.," Environmental Science & Technology, 48(3), 2051-2058.

[40] Alvarez, R.A., S.W. Pacala, J.J. Winebrake, W.L. Chameides, and S.P. Hamburg. 2012. Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences 109:6435–6440.

[41] Costello, Ken. 2013. Lost and Unaccounted For Gas: Practices of State Utility Commissions. Prepared for National Regulatory Research Institute. Report No. 13-06. June. 98 pp

number of recommendations were provided for state utility commissions that address the measurement and use of LAUF in assessing utility performance and cost benefit analyses for investments in emissions reductions.

- The National Association of Regulatory Utility Commissions and the American Gas Association recognize the challenges with defining and managing LAUF. Recent presentations and publications have outlined these challenges. The National Association of Regulatory Utility Commissions has approved a resolution encouraging state regulators and industry to "consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible and to explore, examine and consider adopting alternative rate recovery mechanisms to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems."[42]
- In July 2014, the U.S. EPA Office of Inspector General conducted an evaluation of EPA actions to address methane emissions from the natural gas distribution sector.[43] The report recognizes the challenges with the existing methods and data, and encourages EPA to address financial and policy barriers to emissions reductions. The report also recommends that EPA evaluate data from ongoing external studies in an effort to better define pipeline emissions.

B.2. Other Massachusetts Programs to Reduce LAUF and Emissions

B.2.1. New Massachusetts Legislation for Leak Classification and Reporting

House Bill 4164, Act Related to Natural Gas Leaks Act was signed into law in July 2014 and included several provisions to improve pipeline safety that will also reduce methane emissions. The new law modifies Massachusetts General Laws (MGL) Chapter 164 by adding two new sections regarding reporting and repair of leaks from natural gas distribution systems, and implementation of a targeted infrastructure replacement program for leaking natural gas pipelines. The DPU will develop specific regulations to support the law.

The new law establishes a uniform classification system for natural gas leaks that is consistent with the nationally accepted standard developed by the Gas Pipeline Technology Committee, and endorsed by PHMSA. The new classification provides definitions for three grades of leaks, as well as timeframes for leak repair or main replacement for Grade 1 and Grade 2 leaks. Gas companies must report leak data annually as part of their service quality standard reports.

The new law also prioritizes leak repair in school zones, coordinates pipe inspections and leak repair with planned major roadway construction, and allows for increased surveillance of cast iron pipelines in the winter when frozen ground may increase the likelihood of leaks.

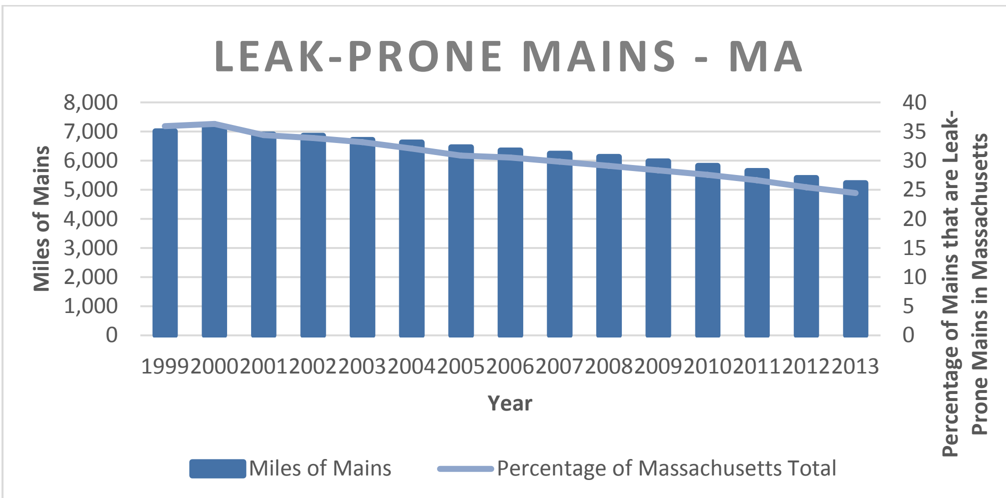
Another significant aspect of the new legislation is the expansion of the accelerated Targeted Infrastructure Replacement Program, which carries a provision requiring elimination of all leak-prone infrastructure within 20 years and allowing accelerated recovery of costs for replacement. This substantially reduces the timeframe for pipe replacement and provides an improved economic model that will result in more rapid emissions reductions.

[42] http://www.naruc.org/Resolutions/Resolution%20Encouraging%20Natural%20Gas%20Line%20Investment%20and%20the%20Expedited%20Replacement%20of%20High%20GAS%20AND%20CI.docx.pdf

[43] U.S. EPA, 2014, Improvements Needed in EPA Efforts to Address Methane Emissions from Natural Gas Pipelines. Office of Inspector General, Report No. 14-P-0324. July. 32 p

B.2.2. Existing Leak-prone Infrastructure

Cast iron and unprotected steel have higher emissions rates per mile of pipe compared to other material types. Figure B-1 shows the miles leak-prone mains and services in Massachusetts. There has been a push to replace this leak-prone infrastructure with other materials, specifically plastic. Since 1999, 25 percent of leak-prone mains and 53 percent of leak-prone services have been replaced in Massachusetts. Leak-prone mains have steadily been replaced over this 15 year period, and leak-prone services were replaced at an accelerated rate for the first 5 years and slowed for the past 10 years. Leak-prone service replacement has fallen to 15 percent in the past 10 years, a substantially slower rate than the first 5 years of this period.



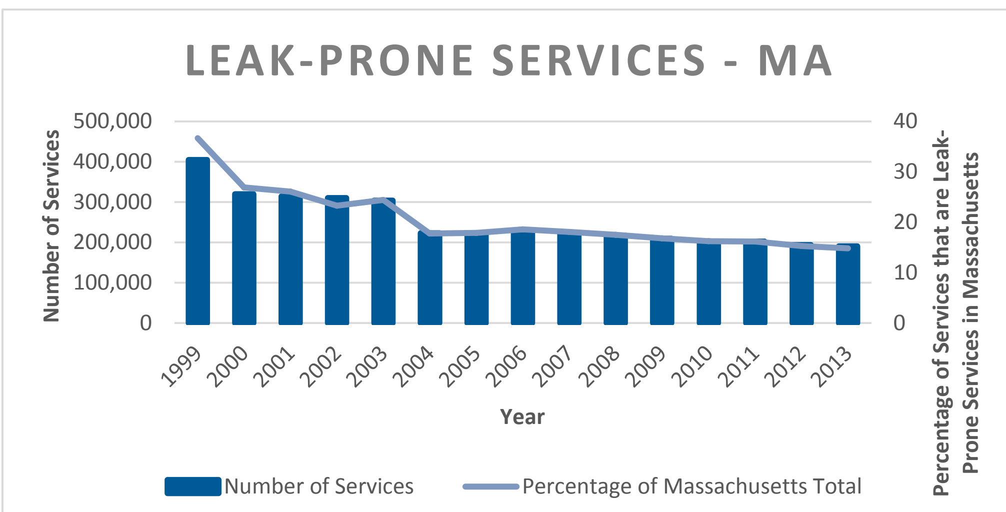


Figure B-1: Leak-prone Mains and Services in Massachusetts

Pipeline mains account for the majority of LDC emissions, and leak-prone mains account for a significant portion of mains emissions across the United States. New York and Pennsylvania currently have the largest number of leak-prone mains. Massachusetts currently has the sixth highest amount of leak-prone mains of any state in the United States. The top ten states are broken out in Table B-1.

Table B-1: States with Most Mileage of Leak-prone Infrastructure

State	Miles of Leak-prone Mains	Percentage of Leak-prone Mains
NY	10,379	14%
PA	10,220	14%
OH	7,378	10%
NJ	6,352	9%
TX	6,049	8%
MA	5,230	7%
MI	3,589	5%
CA	3,233	4%
WV	2,887	4%
IL	1,804	2%
Total	73,701	

A complete picture of the leak-prone mains by total mileage is shown in Figure B-2. Leak-prone mains are found across the country, with a high concentration of leak-prone mains in the northeastern states. California and Texas both are in the top ten for total miles of leak-prone mains, but also have the most and second-most length of pipelines in their states, respectively. Massachusetts had the second highest fraction of leak-prone mains when behind West Virginia.

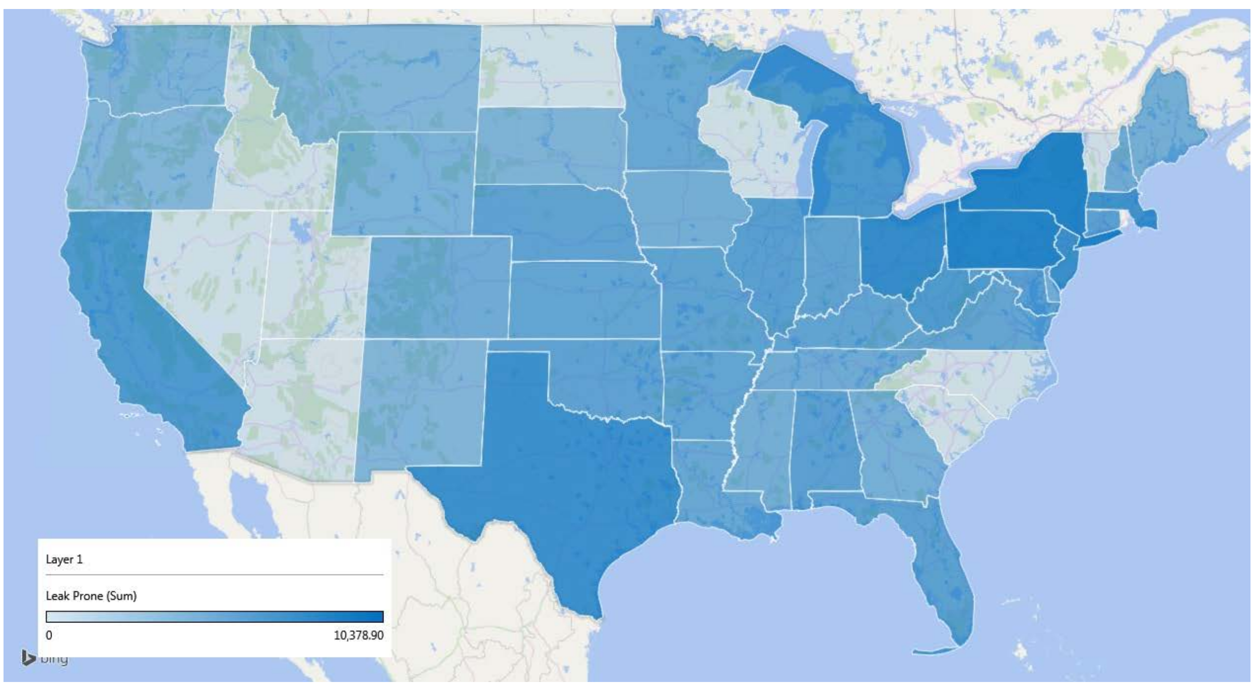


Figure B-2: Leak-prone Mains by State Mileage Across the United States

B.2.3. PHMSA Leaks

The PHMSA does not collect data on the total leak counts. PHMSA does, however, require companies to report the number of hazardous and non-hazardous pipeline leaks repaired during the year, as well as the number of known leaks scheduled for repair. According to PHMSA's definition, "a 'hazardous leak' means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous."[44] In 2013, 14,980 leaks were repaired in Massachusetts, with 3,034 hazardous leaks from mains and 5,553 hazardous leaks from services.

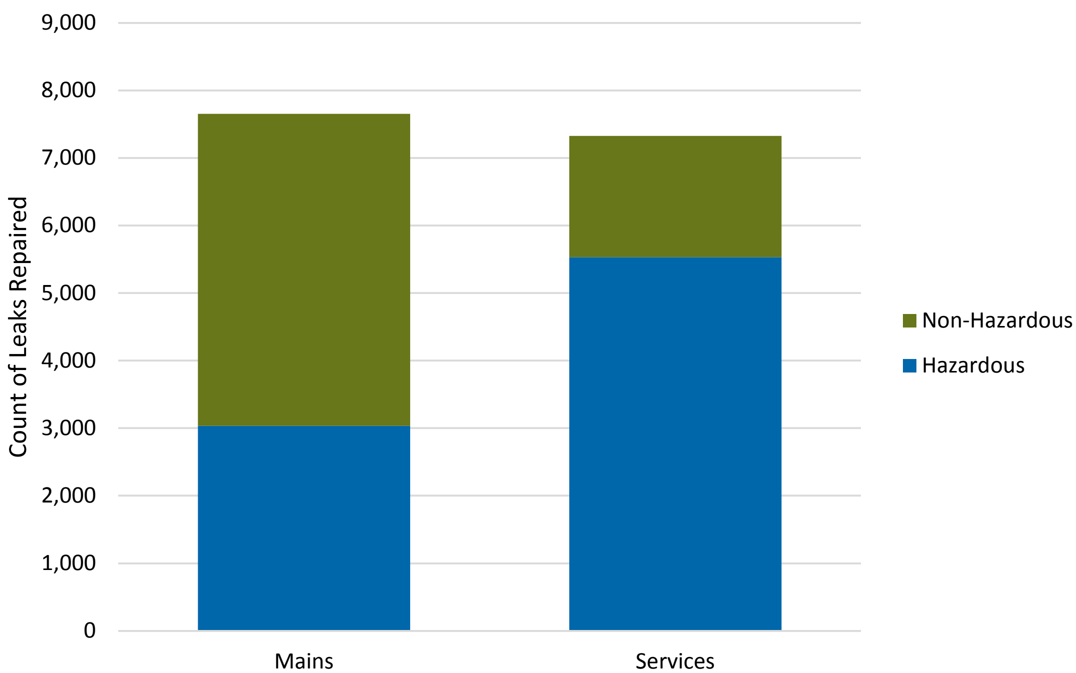


Figure B-3: Count of Leaks Repaired in Massachusetts by Type

In Massachusetts, 7,655 leaks were repaired, which was broken down into hazardous and non-hazardous leaks. By dividing the number of hazardous leaks in the state with the total miles of mains, ICF determined the leaks repaired of a type per mile of mains. With 21,383 miles of mains,[45] Massachusetts repaired 0.14 hazardous leaks per mile compared to the U.S. average of 0.04 hazardous leaks repaired per mile. Additionally the non-hazardous main leaks repaired per mile is also higher than the U.S. average. This does not necessarily mean that there are more leaks in Massachusetts compared to the United States as the data source only includes repaired leaks. Repaired leaks may be indicative of overall leak trends.

[44] PHMSA. Instructions for Completing Form PHMSA F 7100.1-1 (Rev. 01/11) Annual Report for Calendar Year 2010. Achieved: http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_DB68138C257BF49EF164B9C7AD9F8ED685C00000/filename/Gas%20Distr%20Annual%20Report%20Instructions%20-%20PHMSA%20F%207100.1-1%20(01-2011).pdf

[45] PHMSA. Distribution, Transmission & Gathering, LNG, and Liquid Annual Data. Retrieved from: http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

Table B-2: Number of Leaks Repaired per Mile of Mains

Leaks per Mile of Mains	Massachusetts	United States
Hazardous Leaks	0.14	0.04
Non Hazardous Leaks	0.22	0.11

When doing a similar analysis using the service leaks repaired and the total number of services in Massachusetts of 290,522, ICF found that Massachusetts repairs more hazardous leaks per service than other states, but fewer non-hazardous leaks per mile.

Table B-3: Number of Leaks Repaired per Number of Services

Leaks per service	Massachusetts	United States
Hazardous Leaks	0.0024	0.0022
Non Hazardous Leaks	0.0018	0.0050

PHMSA collects data breaking down the repaired leaks from Massachusetts into eight different categories based on the cause of the leak. These categories include corrosion, natural forces, equipment, materials or welds, excavation damages, outside other force damage, incorrect operations or other. The majority of leaks repaired are from corrosion and leaks that do not fall in a category and therefore are listed as other. The breakdown of all the leaks is shown in the figure below.

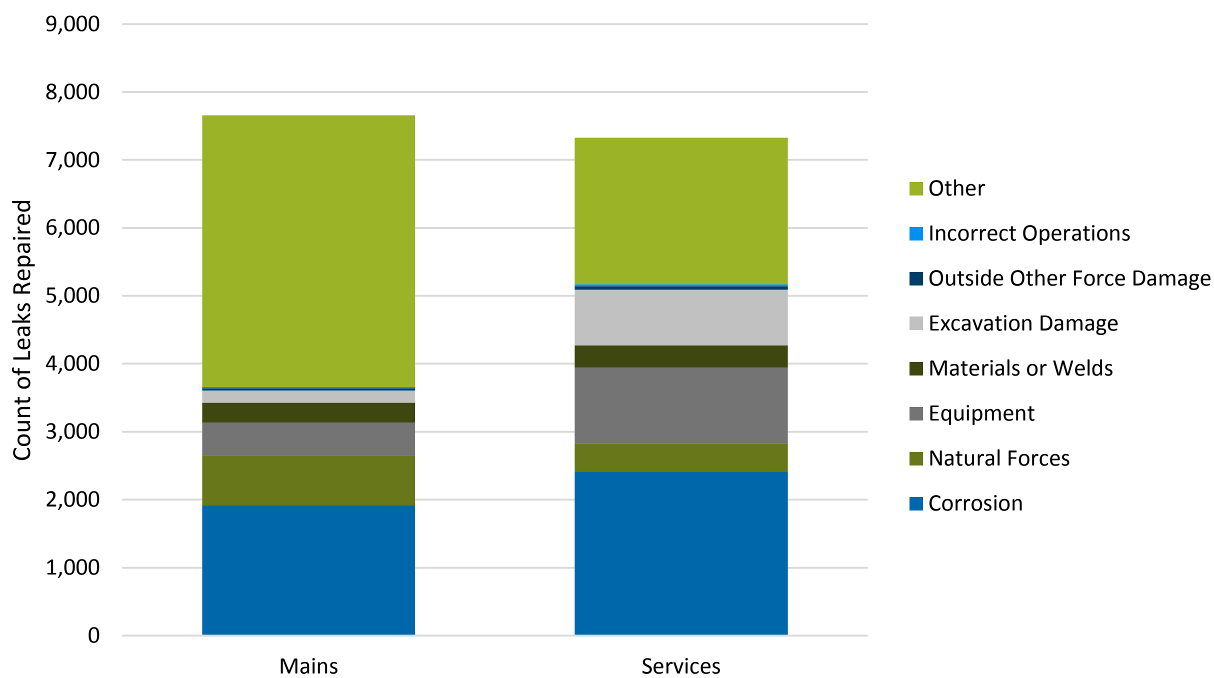


Figure B-4: Count of Leaks Repaired in Massachusetts by Cause

B.2.4. State Incentive Programs

Massachusetts Targeted Infrastructure Recovery Factor (TIRF)

Massachusetts has established a few TIRFs with individual companies that are submitted by the company and approved by the department of public utility. These TIRF programs allow capital expenditures to be recovered on an annual basis instead of having to wait until the next rate case. This reduces the burden for a company, reducing the time between spending the capital and the time when they will be reimbursed for expenditures. Outlined below are two TIRF programs established in Massachusetts.

National Grid

National Grid's TIRF includes capping the capital replacement the company can achieve and pass to the ratepayers, identifying the infrastructure that can be replaced, and identifying how the costs should be assessed. National Grid's TIRF is designed to recover costs associated with replacing non-cathodically protected steel and small diameter cast iron/wrought iron mains.

National Grid recovers the actual costs of the project by a per therm charge based on its annual May 1 TIRF filing which is enacted November 1. The costs passed to consumers include, depreciation, property tax, and a return based on weighted average cost of capital. Highlighted below are a couple of the TIRF's stipulations.[46]

- This cost is limited to 1 percent of Boston Gas-Essex Gas' and Colonial Gas' total revenues from firm sales and transportation revenue adjusted for gas charges. If this cap is exceeded, the excess will be moved to a rate case filing.
- The TIRF would deduct an O&M offset value, $4,557 for Boston Gas-Essex Gas and $2,518 for Colonial Gas per mile from the cost of the project to reflect the savings from having a more reliable infrastructure. In the first filing, the Commission will determine if using a three-year rolling average is necessary.
- National Grid will recover capital costs by adding a per therm value to the base rate from a rate case proceeding.
- The TIRF will verify that there is no unintended double recovery from projects from labor overhead and clearing account burdens.
- National Grid is allowed to receive the same rate of return as other projects.

Bay State

Bay State's TIRF includes capping the capital replacement the company can achieve and pass to the ratepayers, identifying the infrastructure that can be replaced, and identifying how the costs should be assessed. Bay State's TIRF is designed to recover costs associated with replacing bare steel mains, their associated services, tie-ins, and meter move-outs.

Bay State recovers the actual costs of the project in a 12-month period by a per therm charge based on its annual May 1 TIRF filing which is enacted November 1. The TIRF has the following stipulations.[47]

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[46] The Commonwealth of Massachusetts: Department of Public Utilities. D.P.U 10-55. November 2, 2010 http://www.env.state.ma.us/dpu/docs/gas/10-55/11310dpuord.pdf

[47] The Commonwealth of Massachusetts: Department of Public Utilities. D.P.U 9-30. October 30, 2009 http://www.env.state.ma.us/dpu/docs/gas/09-30/103009dpuord.pdf

- This cost is capped at 1 percent of Bay State's total revenues from the previous year. If this cap is exceeded, the excess will be moved to a later filing.
- The TIRF would deduct an O&M offset value, $2,077 per mile to reflect the savings from having a more reliable infrastructure.
- Bay State will recover capital costs by adding a per therm value to the base rate from a rate case proceeding.

States with LAUF Caps

Some states have implemented a maximum allowable percentage of LAUF gas. This cap on LAUF gas is the maximum amount of gas for which companies are allowed to recover costs. If LAUF is higher than the cap, companies have to absorb the cost of unbilled gas above the cap. This is one mechanism states are implementing in an attempt to reduce LAUF gas.

Texas placed an annual cap on the lost gas for the distribution systems at 5 percent between the reporting periods of July 1 to June 30. The Commission has the ability to allow an LDC to exceed the cap due to extenuating circumstances.[48] In Pennsylvania, starting after August 11, 2014, LAUF gas is capped at 5 percent in the first reporting, 4.5 percent in the next year's reporting year, and every year after it drops by 0.5 percent until it reaches a floor of 3 percent.[49] Kansas has placed a 4-percent cap with a penalty mechanism above 4 percent. Kentucky has placed a 5-percent cap on LAUF gas.[50]

Other states are implementing variations on the cap system. Idaho started a temporary cap on LAUF to address the increased number of abnormal volumes of LAUF gas reported. Other states like Indiana have created a cap on a company basis. In Indiana, NIPSCO has a cap of 1.04 percent and Vectren has a cap of 0.8 percent.[51] In New York, a "dead band" approach to LAUF limits has been designed to avoid the impact of natural variability. For actual utility losses within the tolerance band, the utility would recover actual. However, if actual utility losses are outside the tolerance band, the utility would earn an incentive or incur a penalty.

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[48] Texas Administrative Code: Title 16 Part 1 Chapter 7 Subchapter E Rule 7.5525 Retrieved from: http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=7&rl=5525

[49] Title 52 -Public Utilities Pennsylvania Retrieved from: http://www.pabulletin.com/secure/data/vol43/43-32/1476.html

[50] NRRI. Lost and Unaccounted-for Gas: Practices of State Utility Commissions

[51] NRRI. Lost-and-Unaccounted for Gas: State Utility Commission Practices. Available at: http://www.narucmeetings.org/Presentations/Presentation-on-LAUF-Gas%20-NARUC-Gas-Subcommittee-November-17-2013-Costello.pdf

Appendix C. Sample Fact Sheet

See examples on following page.

Lost and Unaccounted for Gas and Emissions from Natural Gas Distribution Systems

Information Sheet
October 2014

What is Lost and Unaccounted for Gas?

Massachusetts Department of Public Utilities defines lost and unaccounted for (LAUF) gas in the Service Quality Guidelines as “the differential between the amount of gas that enters the Company’s city-gates, and the amount of gas billed to customers, expressed as a percentage of the amount of gas that entered the Company’s city-gates.” This value is reported annually to the Department by each Local Distribution Company in the Annual Return and Service Quality reports. Federal agencies, such as the Pipeline and Hazardous Materials Safety Administration, and the Energy Information Administration also require reporting of LAUF; however, these definitions differ from Massachusetts.

Is Lost and Unaccounted for Gas the same as emissions?
No. Emissions are just one of several components that may contribute to the total amount of LAUF. Many other factors contribute to LAUF including:

Company (Own) Use	Gas used by the LDC for building heat, backup power generation, and use in process equipment. Most companies account for this use.
Storage/Withdrawal Adjustments	“Accounting” adjustments to the inventory of stored natural gas. Can include deliveries of LNG from outside the system.
Soft Closes	Gas that is used at a location, but not explicitly billed to a customer. Usually occurs between tenants at the same location.
Theft	Gas that is stolen from the system, often by illegally accessing the distribution pipes or bypassing the meter.
Line Pack Changes	The line pack is the amount of gas that is needed to fill the distribution system pipelines. Changes occur when new pipes are added to the system.
Intentional Venting	The intentional release of gas to the atmosphere. Usually through a designed vent (e.g., a pneumatic device) or during pipeline maintenance and repair.
Dig-Ins/Mishaps	The unintentional release of gas from external damages to the pipeline.
Meter Error	Correction to account for the average bias of the meters in the system. This can be a positive or a negative value, depending on if the meter is running slow or fast.
Billing Cycle Adjustments	Correction to account for the fact that monthly customer billing cycles do not match up exactly with the reporting cycles.
Composition Corrections	Some gas companies account for gas based on the heat content, not volume. Conversion to volume can introduce inaccuracy.
Adjustments for Non-Metered Gas	Some sources of gas are not metered (old municipal street lights). Usually, very few of these small sources exist.

What emissions are included in LAUF?

The short answer to this question is that all emissions sources from LDC companies are included in LAUF. The definition of LAUF is defined as the difference between the amount of gas that enters the Company's city-gates, and the amount of gas billed to customers. This means emissions are included in the LAUF value. These emissions include leaks from pipeline mains and services which can be leaks from corrosion, natural forces, excavation damages, inadequate welds, equipment, operations or other sources along the pipeline. Additionally, emissions from metering and regulating stations are included where emissions come from blowdowns, pneumatic devices, isolation valves, odorizer vents, heaters, and any fugitive emissions. Emissions also come from residential, commercial and industrial meters, and pressure relief valves.

Do all emissions from pipelines go to the atmosphere?

No, a small amount of methane gas emitted from underground pipelines can be decomposed within the soil column by natural oxidation and biological activity before it reaches the surface. Because of this soil oxidation, the amount of gas that is actually released to the atmosphere is less than the amount of gas lost in the distribution system. The pipeline emissions factors used to estimate methane emissions account for this soil oxidation. For LAUF calculations, emissions factors should not include soil oxidation factor. Soil oxidation factor is appropriate for air emissions analysis.

Are there requirements that provide for how to calculate LAUF?

No, not at this time. The Department is currently looking into developing a standard method for calculating LAUF to provide consistency and transparency. The U.S. EPA Greenhouse Gas Reporting Program, Subpart W (40 CFR 98.232) provides guidance on how to calculate emissions from a natural gas distribution system.

Are there requirements for calculating emissions?

The U.S. EPA Greenhouse Gas Reporting Program, Subpart W (40 CFR 98.232) provides guidance on how to calculate emissions from a natural gas distribution system. In Subpart W, distribution companies that exceed the 25,000 metric tons CO2e per year must report emissions from meters and regulators and all associated equipment at these stations. Also distribution companies report fugitive emissions at metering and regulating stations, emissions from meters, pipeline mains leaks, service line leaks and combustion sources. Subpart W provides guidance on how to estimate emissions from each of these sources.[52]

In state inventories and the U.S. GHG Inventory, emissions are calculated by knowing an average emissions rate per given device and then extrapolating this value to all of the devices. This emissions rate is typically referred to as an emissions factor and the number of devices is known as the activity factor. These average emissions factors are taken from a variety of publicly available studies

[52] U.S. EPA Greenhouse Gas Reporting Program, Subpart W (40 CFR 98.232) Retrieved from: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=ab6521db5955a430f5bb0d5cf0bd94d7&n=pt40.21.98&r=PART&ty=HTML#sp40.21.98.w