Energy & Infrastructure Program

Energy Project

Natural Gas Infrastructure and Methane Emissions

September 2014

BIPARTISAN POLICY CENTER

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Introduction

Significantly increased production of natural gas in the United States has dramatically changed the country's energy landscape—both lowering domestic natural gas prices and providing substantial economic benefits.[1] At the same time, debate has surrounded the environmental impacts of natural gas as compared with other fossil fuels.[2]

Specifically, given that natural gas contains less carbon than either coal or oil, it produces less carbon dioxide when burned, yielding substantial climate benefits.[3] On the other hand, natural gas is composed largely of methane, a greenhouse gas (GHG) more potent than carbon dioxide; therefore, the overall emissions benefits of natural gas hinge critically on earlier stages in the natural gas lifecycle—production, transportation, and distribution—and specifically on the amount of methane that is released into the atmosphere without being combusted.[4]

Prompted by these uncertainties and the need to better understand the climate impacts of increased natural gas production and use, researchers have been investigating natural gas emissions throughout its lifecycle. For example, the nonprofit Environmental Defense Fund (EDF)—in concert with a large number of academic and industry partners—is conducting more than a dozen studies of its own, which cover natural gas production, gathering, transmission, storage, distribution, and transportation.[5] Other research has had a more narrow focus, such as a study from scientists at Boston University and Duke University, which mapped natural gas pipeline leaks in Boston.[6] These studies and others have used a variety of techniques to measure emissions, including engineering estimates, direct measurements at sites of interest, and measurements taken from downwind or aerial locations.[7] In all, due to the complexity of the topic and differences in research results, there has been significant discussion, concern, and controversy surrounding the actual volumes of methane emissions arising from natural gas production, transmission, and distribution.

In June 2013, President Obama announced his Climate Action Plan to address climate change through emissions mitigation, adaptation, and international efforts. In March 2014, the administration released a Strategy to Reduce Methane Emissions (Methane Strategy)—a key element called for in the president's plan—that specifically targets the identification, measurement, and reduction of methane emissions.[8]

As part of this Methane Strategy, the U.S. Department of Energy (DOE) held a series of in-depth roundtables to solicit thoughts from a variety of stakeholders on opportunities to modernize natural gas infrastructure and reduce associated emissions.[9] At the last of these roundtables, DOE also announced a series of initiatives, as well as enhancements to existing programs, that aim to modernize natural gas transmission and distribution systems. The initiatives relate to a spectrum of topics, including compressor efficiency, pipeline replacement, forward-looking analysis, and research and development for new technologies. The announcement also outlines new partnerships and enhanced coordination within the administration and with stakeholders, and highlights a number of commitments from businesses, trade groups, and nonprofit organizations that have pledged to continue their leadership on methane leakage reductions. These initiatives, commitments, and other actions—although striving to reduce methane emissions—are largely voluntary.[10]

Likewise prompted by the administration's Methane Strategy, the U.S. Environmental Protection Agency (EPA) has released a series of five technical white papers—including input from independent experts—that detail potentially significant sources of methane emissions from the oil and natural gas sectors.[11] The Methane Strategy also calls for EPA to determine in the fall of 2014 how best to reduce emissions from these sources and if needed, to complete any additional regulations by the end of 2016.[12]

EPA does not currently regulate methane emissions from the distribution sector, and a recent report released by EPA's inspector general concludes that further work is required by the agency to address methane emissions from natural gas transportation systems.[13] Among other actions, the report recommends that EPA create and implement a framework to tackle the financial and policy barriers to fixing distribution pipeline leaks and to establish yearly performance goals for reduction of methane emissions through EPA's voluntary programs. Although the inspector general's evaluation does not necessarily call for increased regulation, it does urge EPA to assess whether the annual goals are being met and, if not, to consider changes or other options—including whether regulation under the Clean Air Act would be appropriate.

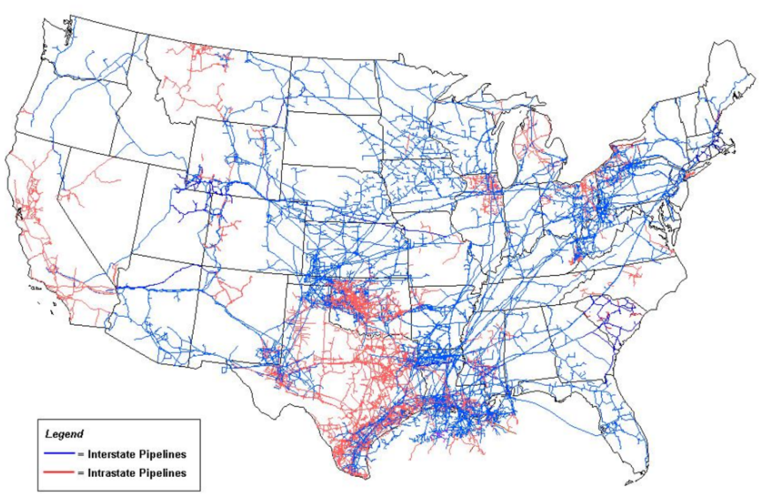
Within the context of increased domestic natural gas production and use, as well as concerns related to climate change, this staff paper from the Bipartisan Policy Center provides an overview of some of the structural and safety aspects of the U.S. natural gas transmission and distribution system, while also exploring issues related to methane emissions from these natural gas systems.

Background on U.S. Natural Gas Pipelines

The United States has a large natural gas pipeline network that stretches across the country and provides gas transportation services to each of the lower 48 states (Figure 1).[14]

According to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), there are basically three different types of natural gas pipeline systems: gathering, transmission, and distribution.[15] Gathering pipelines transport gas from where it is produced—at the wellhead—to transmission lines.[16] These lines, in turn, bring gas to storage facilities, large customers, and distribution systems.[17] Finally, distribution lines—which can be further categorized as "mains" and "service lines"—carry gas to consumers.[18]

Figure 1. U.S. Natural Gas Pipeline Network, 2009



Source: U.S. Energy Information Administration,
http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html.

PHMSA reports that in 2013, the United States contained more than 320,000 miles of natural gas gathering and transmission pipelines, and more than two million miles of gas distribution pipelines (counting both mains and the estimated length of service lines).[19,20] U.S. pipeline capacity has seen robust growth over the past several years, driven in large part by the rapid increase in domestic shale gas production.[21]

History and Regulations

Pipeline transportation of oil and natural gas in the United States has a history dating to the 19th century. With the boom of commercial oil production in the mid-1800s came the need for transportation to markets, which at first was satisfied by boats and then later by railroad.[22] One of the first, long-distance natural gas pipelines—measuring 120 miles—was built in 1891 between central Indiana and Chicago.[23] The first gas pipeline that extended more than 200 miles spanned from Louisiana to Texas and was constructed in 1925.[24] These examples notwithstanding, DOE notes that few natural gas pipelines were, in fact, built before World War II; it was not until the 1950s and 1960s that thousands of miles were constructed across the country.[25]

Natural gas pipelines are regulated at both the state and federal levels, with primary federal oversight provided by PHMSA, under the U.S. Department of Transportation.[26] According to its website:

> *"PHMSA… develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air."*[27]

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 reauthorized PHMSA's pipeline safety programs through fiscal year 2015 and addressed a number of regulatory and other matters.[28] Natural gas pipeline safety regulations are codified under 49 CFR Part 192 and present minimum performance standards that must be adopted by states. (States have the option to issue more stringent regulations if they choose.) PHMSA also administers a federal grant program to reimburse states up to 80 percent of the cost of operating their safety programs.[29]

PHMSA has a number of long-standing safety, environmental, and other initiatives. For instance, the agency worked with stakeholders to develop the Distribution Integrity Management Program (DIMP), which requires each natural gas distributor to create and implement a comprehensive program for identifying, ranking, and addressing pipeline system risks.[30] PHMSA has also developed a Transmission Integrity Management Program that, among other things, similarly focuses on assessment of high-risk pipeline areas and requires transmission operators to develop Integrity Management Programs.[31]

Pipeline Materials

Natural gas pipelines have historically been made from a variety of materials of differing quality and durability. Modern gathering and transmission pipelines are generally made of steel. Distribution pipelines can be constructed from a range of materials—such as cast iron, steel, or copper—though plastic is most frequently used.[32]

Natural gas steel pipelines that were installed after July 31, 1971, must be coated and have cathodic protection. Both of these measures help to prevent (or at least to mitigate) naturally occurring corrosion. Proper coating on the exterior of steel pipelines inhibits the reaction of the metal with its environment, and cathodic protection imparts a direct current to the pipeline to further prevent the corrosion process.[33] For steel pipelines installed before July 31, 1971—and that are bare steel or coated only—cathodic protection is required in areas exhibiting active corrosion, as determined by an electrical survey or other acceptable method per federal regulations.[34]

PHMSA recommends polyethylene as the most suitable plastic pipe for natural gas transportation, though not for aboveground applications.[35] According to the American Gas Association (AGA), plastic pipe does not corrode and is less expensive to install and maintain than steel or cast iron.[36]

Gathering, transmission, and distribution main pipelines can range in size from approximately two inches to 42 inches in diameter, while distribution service lines generally have a diameter of a half-inch to two inches.[37]

Leaks and Safety

Pipeline leaks have varying causes and potential consequences and so are generally treated individually. Cast/wrought iron and bare steel pipelines pose an increased risk, as many were installed decades ago.[38] At the same time, AGA notes that age is not the only factor used to determine which pipelines should be replaced, as some older pipelines can continue to be both safe and reliable.[39]

PHMSA defines a "leak" as a "small opening, crack, or hole in a pipeline allowing a release of oil or gas."[40] The rate at which gas escapes depends on both the size of the hole and the pressure, and the leakage rate can increase over time if the leak is not located and repaired.[41] There are a variety of different methods to measure natural gas leaks, based on a spectrum of different technologies; these include acoustic methods that detect the noise generated by escaping gas, optical methods that perceive radiation, and sampling methods that measure hydrocarbon vapors in the air.[42] There are also software-based or electronic methods—varying significantly in their levels of complexity—that monitor one or more variables (such as volume and pressure) at multiple points along the pipeline network to infer the presence of leaks.[43] In an effort to increase the effectiveness of their leak detection programs, many operators use more than one technique.[44]

Federal regulations require periodic tests and inspections to ensure the safety of distribution systems. PHMSA's DIMP calls on operators to evaluate the effectiveness of their respective leak management programs, including the process by which they locate, classify, and respond to leaks. With the approval of the appropriate regulatory authority, an operator may adjust the frequency of required periodic actions based on the findings from its integrity management program and other analyses.[45]

According to the PHMSA, accidental excavation damage is one of the greatest challenges to the safe operation of pipelines.[46] Between 1994 and 2013, excavation damage was the reported cause of approximately 15 percent of onshore natural gas transmission pipeline "significant"[47] incidents and the reported cause of nearly 37 percent of gas distribution pipeline significant incidents; together, these incidents resulted in more than $275 million of property damage (2013 dollars), hundreds of injuries, and 130 fatalities.[48] Several organizations, including the Common Ground Alliance[49] and the Pipeline Safety Trust,[50] are working to raise awareness of buried pipelines and to decrease the frequency of excavation damage.

The Gas Piping Technology Committee (GPTC) has developed guidance for classifying natural gas leaks on a three-degree scale.[51] The definitions for each grade are as follows:

- *Grade 1*: "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."
- *Grade 2*: "A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard."
- *Grade 3*: "A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."

Leak designations are not based on volume alone, but take into account a number of other factors, including proximity to structures. For example, "Grade 1" leaks can be service pipeline leaks of low volume that command high priority due to their location near or within buildings and homes. The severity of "Grade 2" leaks can vary widely and, per GPTC guidance, should be repaired or cleared within one year or 15 months at the most.[52]

Pipeline Replacement

Pipelines of different materials are susceptible to degradation through a number of means: cast iron can become brittle and crack; steel can become corroded. Although many believe that there is little need to replace plastic pipe, some of these lines may also be at risk.[53] Pipeline replacement can be difficult and costly, with great variation depending on the location of the project.

The Interstate Natural Gas Association of America (INGAA)—which represents interstate natural gas pipeline companies[54]—states the following with regards to transmission pipeline replacement:[55]

> *"Direct replacement of natural gas pipelines, entailing replacement of natural gas pipelines along the same route at the same capacity, is relatively rare. From 1997 to 2008, less than 100 miles of pipeline per year was replaced out of the 300,000 miles of pipeline on the U.S. natural gas transmission system. Pipelines are more often indirectly replaced as a consequence of expansions and/or abandonment."*

PHMSA provides data on U.S. transmission pipeline material types (Table 1).[56] The vast majority of these pipelines are coated and cathodically protected steel, helping to reduce the possibility for corrosion and leakage.

Table 1. U.S. Onshore Natural Gas Transmission Pipelines by Material, 2013

MATERIAL	MILES OF PIPELINE	PERCENTAGE OF TOTAL
Steel		
Cathodically protected, coated	286,676	97.1%
Cathodically protected, bare	5,931	2.0%
Cathodically unprotected, coated	527	0.2%
Cathodically unprotected, bare	838	0.3%
Other Materials		
Plastic	1,044	0.4%
Cast Iron	0	0.0%
Wrought Iron	57	0.0%
Composite	3	0.0%
Other	59	0.0%
Total	**295,135**	**100.0%**

Notes: These numbers are taken from PHMSA's 2013 Gas Transmission & Gathering Annual Data. The totals are for onshore transmission pipelines carrying natural gas only. The sum of the categories may not equal the total due to independent rounding.

With regards to distribution systems, a July 2012 report prepared for the American Gas Foundation (AGF) by Yardley Associates discusses a number of issues surrounding natural gas pipeline replacement.[57] The report notes that before 1940, distribution pipelines were most often made of wrought/cast iron and then, for several decades thereafter, of steel. In the 1970s, systems of smaller diameter were increasingly made of plastic. The report indicates that bare steel, unprotected coated steel, cast/wrought/ductile iron, and copper are the distribution pipeline materials most susceptible to corrosion and leaks. ("Other" pipelines are not included in this list, due to uncertainty regarding their need for replacement.)[58] Similar to transmission pipelines, PHMSA also provides data on the material composition of distribution main and service pipelines in the United States (Table 2).[59]

Approximately 7.4 percent of distribution mains (by length) and about 6.8 percent of distribution services (by count) are made of the "most susceptible" materials. The vast majority of the remainder is made of plastic and cathodically protected and coated steel.

Table 2. U.S. Natural Gas Distribution Pipelines by Material, 2013

MATERIAL	DISTRIBUTION MAIN (MILES)	PERCENTAGE OF TOTAL	DISTRIBUTION SERVICES (COUNT)	PERCENTAGE OF TOTAL
Steel				
Cathodically protected, coated	473,000	37.7%	14,421,134	21.5%
Cathodically protected, bare	13,093	1.0%	354,558	0.5%
Cathodically unprotected, coated*	16,724	1.3%	1,630,753	2.4%
Cathodically unprotected, bare*	43,892	3.5%	1,977,876	2.9%
Other Materials				
Plastic	674,038	53.8%	46,133,350	68.7%
Cast/Wrought Iron*	30,888	2.5%	11,991	0.0%
Ductile Iron*	672	0.1%	320	0.0%
Copper*	24	0.0%	973,074	1.4%
Other	1,020	0.1%	1,612,341	2.4%
Total	**1,253,350**	**100.0%**	**67,115,397**	**100.0%**

*Notes: *These distribution pipeline materials are the most susceptible to corrosion and leaks according to the AGF/Yardley Associates paper. All numbers are taken from PHMSA's 2013 Gas Distribution Annual Data. The sum of the categories may not equal the total due to independent rounding.*

AGF's report notes that although public safety and supply reliability are the primary drivers of operators' efforts to address leak-prone pipelines, "an important secondary objective is to manage the level of costs incurred, particularly for LDCs [local distribution companies] that have significant replacement challenges."[60] This highlights the importance of prioritization in pipeline replacement, given that costs can often be significant.

Figures from INGAA state that from 1993 to 2007, natural gas pipeline building costs ranged between $30,000 and $100,000 per inch-mile (based originally on Federal Energy Regulatory Commission data for large-diameter gas pipelines between 30 and 36 inches).[61] To give a more concrete illustration, these figures imply that a 30-inch-diameter pipeline would cost somewhere between $900,000 and $3 million per mile.

In 2012, the California Public Utilities Commission's Division of Ratepayer Advocates (DRA) calculated "industry estimates" of pipeline replacement costs for several pipeline sizes and levels of congestion. These were originally generated in response to numbers submitted by Pacific Gas and Electric Company (PG&E), and here are used for illustrative purposes. DRA's figures purposely overestimate—by 40 percent—actual expected costs from "competitively bid materials, services, equipment and labor." DRA explains this choice by saying that "at the conceptual design phase, it is standard practice to overestimate costs as a way to capture unknowns," and in the context of DRA's assessment of PG&E's estimates, this was applicable.[62,63]

Table 3 presents DRA's cost estimates for four pipe size ranges and three levels of congestion.[64] These estimates include the costs for pipe, anti-corrosion coating, welding, trenching, and indirect expenditures. (DRA used PG&E's original figures for indirect expenditures.) The DRA report notes that for onshore pipelines, costs are dominated by labor and equipment rentals (for digging and refilling trenches), rather than by expenditures associated with steel, welding, and pipeline coating. The more congested an area, the greater the share of costs represented by labor and equipment.[65]

Table 3. Natural Gas Pipeline Replacement Cost Estimates

PIPE SIZE RANGE	COST (MILLIONS OF DOLLARS PER MILE)		
	NON-CONGESTED AREAS	SEMI-CONGESTED AREAS	HIGHLY CONGESTED AREAS
10"	\$0.6	\$1.3	\$2.1
16"	\$1.1	\$2.0	\$3.2
24"	\$2.0	\$3.4	\$5.2
36"	\$4.0	\$6.2	\$8.9

Note: These estimates are based on figures originally calculated by the California Public Utilities Commission's Division of Ratepayer Associates.

Note that these estimates are generally higher than the numbers provided by INGAA, when comparing pipeline diameters of similar sizes. This may be partially due to DRA's purposeful overestimation, but it is also likely a result of changing economic factors, given that the DRA figures are several years more recent than those cited from INGAA.

Methane Emissions from Natural Gas Pipelines

Increased domestic production and use of natural gas has drawn attention to the potential environmental implications of aging natural gas infrastructure. Specifically, a number of researchers throughout government, industry, academia, and the nonprofit sector have conducted studies aiming to locate and quantify the scale of methane emissions associated with transmission and distribution pipelines. Differences in results—in some cases arising from the inherent challenges in measuring such emissions—have led to significant discussion, concern, and controversy.

There are several methodologies to estimate methane emissions from natural gas pipeline systems. Two of these techniques—one based on estimates using industry and other data, and the other based on reporting directly from facilities—are explored below in the context of concrete examples.

National Greenhouse Gas Inventory

To meet its commitments under the United Nations Framework Convention on Climate Change, the U.S. government—through the EPA—publishes an annual inventory that estimates and reports all U.S. anthropogenic GHG emissions.[66] These inventories are an example of emissions estimates based on available data, both from industry and from other sources. EPA's most recent GHG Inventory was released in April 2014[67] and found that for 2012, GHG emissions totaled 6,526 million metric tons of CO_2-equivalent. The primary emissions sources in that year were electricity production (32 percent), transportation (28 percent), industry (20 percent), commercial/residential (10 percent), and agriculture (10 percent).[68]

The inventory also found that natural gas system emissions decreased substantially between 1990 and 2012: 17 percent for methane emissions and 7 percent for non-combustion CO_2 emissions.[69] Although natural gas systems were the second-largest source of U.S. methane emissions in 2012 (accounting for approximately 23 percent of that category), they represented only about 2 percent of total U.S. GHG emissions that year on a CO_2-equivalent basis.[70]

Considering distribution systems alone, methane emissions declined approximately 23 percent between 1990 and 2012, despite the addition of 300,000 miles of distribution lines during that period. (Non-combustion CO_2 emissions from distribution were less than 0.1 million metric tons CO_2-equivalent over those years.)[71] The table below shows the transmission, storage, and distribution emissions figures provided in EPA's 2014 GHG Inventory, covering selected years between 1990 and 2012.

Table 4. EPA GHG Inventory: Gas Transmission, Storage, and Distribution Emissions, 1990-2012

(million metric tons CO_2-eq.; Net Emissions = Calculated Potential – Captured/Combusted)

NATURAL GAS SEGMENT	1990	2005	2008	2009	2010	2011	2012
Transmission and Storage							
Calculated Potential	49.2	51.9	52.5	52.5	52.7	52.7	51.7
Captured/Combusted	< 0.1	10.6	9.5	8.2	9.4	7.5	8.2
Net Emissions	49.2	41.2	43.1	44.3	43.4	45.2	43.5
Distribution							
Calculated Potential	33.4	30.8	30.7	30.0	29.2	28.8	26.8
Captured/Combusted	< 0.1	1.0	1.1	1.3	1.1	1.2	0.9
Net Emissions	33.4	29.7	29.6	28.7	28.1	27.5	25.9

Source: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Chapter-3-Energy.pdf, page 3-64.

As shown in the table, EPA uses a multistage approach to estimating these emissions.[72] The "calculated potential" emissions are based on activity data obtained from a number of different organizations (including PHMSA); combining those data with emissions factors, EPA calculates the potential GHG impact of the various natural gas system segments. The emissions factors are derived from data collected in 1992 and published in 1996 as part of a Gas Research Institute (GRI) and EPA study. Given that these factors do not account for significant industry and regulatory changes since that time, the "calculated potential" numbers are adjusted downward through the use of more recent data regarding voluntary and mandatory actions. These adjustments are shown in the "captured/combusted" rows in the table, and the resulting "net emissions" are those that EPA uses in its official inventory. As discussed in more detail below, concerns about the accuracy of the emissions factors has led to a number of adjustments (as seen here), as well as to current efforts to develop completely new factors.

Greenhouse Gas Reporting Program

Another approach to estimating natural gas system emissions is to use numbers directly reported from facilities. In response to the Consolidated Appropriations Act of 2008,[73] EPA issued the Mandatory Reporting of Greenhouse Gases Rule, which aims to provide accurate and timely GHG emissions data for policymaking purposes.[74] The implementation of the rule is known as the Greenhouse Gas Reporting Program (GHGRP). The GHGRP is limited in its scope, given that only facilities emitting more than 25,000 metric tons per year of GHGs are required to submit annual reports to EPA.[75] Under the program, yearly emissions data were first due in September 2011 for the 2010 calendar year, though the submission deadline for some emissions categories was set one year later. (This second group includes the natural gas sources described below.)[76]

Subpart W of the rule outlines the reporting requirements for facilities that contain petroleum and natural gas systems.[77] Covered sources include natural gas processing, transmission, storage, and distribution, as well as onshore and offshore petroleum and natural gas production. (LNG import/export terminals and LNG storage are also reported under Subpart W.)[78] The summary for the 2012 data notes that the petroleum and natural gas systems category does not include gathering/boosting, transmission lines between compressor stations, and vented emissions from hydraulically fractured oil wells.[79] Keeping those exclusions in mind, some selected natural gas results are presented in Table 5 below.

Table 5. GHG Reporting Program: Gas Transmission, Storage, and Distribution Emissions, 2012

(million metric tons CO_2-eq.; facilities with annual emissions ≥ 25,000 metric tons per year)

NATURAL GAS SEGMENT	REPORTED EMISSIONS
Transmission (462 facilities)	23.0
Selected sub-categories:	
Combustion equipment (CO_2)	19.2
Reciprocating compressors (CH_4)	1.6
Blowdown vent stacks (CH_4)	1.1
Underground Storage (49 facilities)	1.3
Selected sub-categories:	
Combustion equipment (CO_2)	0.9
Reciprocating compressors (CH_4)	0.2
Distribution (174 facilities)	13.0
Selected sub-categories:	
Distribution mains (CH_4)	7.9
Distribution services (CH_4)	4.0
Combustion equipment (CO_2)	0.3

Source: http://www.epa.gov/ghgreporting/documents/pdf/2013/documents/SubpartW-2012-Data-Summary.pdf.

In a process similar to that used in EPA's GHG inventory, GHGRP emissions from natural gas distribution mains and services were calculated by "multiplying population counts [miles of pipeline or number of services] by default emission factors that are specific to pipe material."[80] These emission factors are given in Table W-7 of Subpart W, and contain separate factors for distribution mains and distribution services.[81] These factors are based on values given in the appendix to EPA's 2009 GHG Inventory, which were themselves a result of adjustments to the EPA/GRI 1992 figures described above.[82] (EPA's 2014 Inventory continues to use the same distribution system emissions factors as presented in the 2009 Inventory.)[83]

Note that the sum of the transmission and storage GHGRP emissions for 2012—approximately 24 million metric tons CO_2-equivalent—is significantly less than the nearly 44 million metric tons CO_2-equivalent reported in EPA's GHG inventory for the year 2012 (Tables 4 and 5). A similar comparison can be made for distribution emissions in 2012: 13 million metric tons CO_2-equivalent from the GHGRP versus nearly 26 million metric tons CO_2-equivalent from EPA's most recent inventory. These differences reflect not only the limited scope of the GHGRP, but likely methodological variations as well.

Emissions Factors

The methodologies for both EPA's GHG Inventory and for the GHGRP (with regards to natural gas distribution systems) highlight the importance of emissions factors in the estimation process. These factors are meant to embody representative rates of leakage from each distribution main or distribution service material and are based on data recorded from existing pipeline systems.

Motivated by the climate uncertainty surrounding increased use of natural gas, the EPA/GRI study aimed to quantify the GHG emissions from U.S. natural gas operations for the base year 1992 (the final results were published in 1996).[84] The ninth volume of the publication discusses underground pipelines specifically, and presents eight emissions factors for distribution systems: four factors for distribution mains and four factors for distribution services.[85] As described above, these factors are still in use today, either directly or in altered forms. At the same time, EPA provides a cautionary note in the annex to its 2014 GHG Inventory:[86]

> *"Since the time of [the EPA/GRI] study, practices and technologies have changed. While this study still represents best available data in many cases, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions."*

As such, EPA uses these factors as the basis for its calculations of "potential" methane emissions, but then employs current data to subtract emissions based on regulatory and voluntary activities.[87]

The EPA inspector general report discussed in the introduction to this paper notes that there was significant uncertainty in the EPA/GRI study, due in some cases to small sample sizes and large variation in measurements.[88] The report also states that EPA has not conducted any direct measurement studies on distribution emissions since the 1996 study. In even stronger language, a letter from the American Public Gas Association is critical of the 1992 emissions factors—and the Subpart W factors based on them—stating that they are not representative of the industry as a whole. The letter further argues that the EPA/GRI study contained a number of critical errors, which leads to factors that overstate the total leakage from distribution systems.[89]

Table 6 lists emissions factors from the EPA/GRI study, two EPA inventories, and Table W-7 from GHGRP's Subpart W.

Overall, the age of the EPA/GRI data, in addition to other concerns, has motivated the collection of newer measurements. For instance, Washington State University's Laboratory for Atmospheric Research is leading a nationwide field study to better quantify natural gas distribution system emissions, which can then be used to derive updated emissions factors.[90] The university is collaborating with several major natural gas utilities and EDF to complete its work, and the researchers expect to publish their results in a peer-reviewed journal by the end of 2014.[91]

Table 6. Natural Gas Distribution System Emissions Factors by Material

PIPE USE	MATERIAL	EPA/GRI (1996)[92]		EPA GHG INVENTORIES (2009; 2014)[93]		GHGRP SUBPART W TABLE W-7[94]	
Main	Unprotected Steel	51,802	scf/leak-yr	110.19	Mscf/mile-yr	12.58	scf/mile-hr
	Protected Steel	20,270	scf/leak-yr	3.07	Mscf/mile-yr	0.35	scf/mile-hr
	Plastic	99,845	scf/leak-yr	9.91	Mscf/mile-yr	1.13	scf/mile-hr
	Cast Iron	238,736	scf/mile-yr	238.70	Mscf/mile-yr	27.25	scf/mile-hr
Service	Unprotected Steel	20,204	scf/leak-yr	1.70	Mscf/serv.-yr	0.19	scf/serv.-hr
	Protected Steel	9,196	scf/leak-yr	0.18	Mscf/serv.-yr	0.02	scf/serv.-hr
	Plastic	2,386	scf/leak-yr	0.01	Mscf/serv.-yr	0.001	scf/serv.-hr
	Copper	7,684	scf/leak-yr	0.25	Mscf/serv.-yr	0.03	scf/serv.-hr

Broadly speaking, there is still considerable debate surrounding the life-cycle emissions of natural gas, with estimates spanning a wide range.[95,96] This variation illustrates the uncertainty in these estimates and calls for further research to understand the causes of the differences.

Lost and Unaccounted-For Gas (LUFG)

Lost and unaccounted-for gas, sometimes referred to as LUFG,[97] is the difference between the amount of gas purchased by a distribution company—which then enters its pipeline system—and the amount of gas it sells to its customers.[98] A more detailed definition, including some causative factors, is provided by AGA:[99]

> *"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."*

A nearly identical definition is given by PHMSA,[100] and both definitions note that LUFG is not synonymous with "leaked gas." As discussed more in the next section, LUFG values—as currently calculated and reported—can be the result of more than a dozen factors, many of which are independent of leaks. In many cases, the exact causes of LUFG are not precisely known, so LUFG is often reported as a single aggregated figure. For a typical utility, it is generally between 2 and 5 percent of the total gas entering the distribution system.[101]

Some studies have used reported LUFG values to calculate the potential methane emissions from natural gas distribution systems.[102] However, given the uncertainty and lack of precision surrounding LUFG measurements, LUFG is likely not (or at least not yet) an accurate metric to use in estimating methane emissions from these systems.

At the same time, changes to how LUFG is calculated and reported may increase its usefulness for this purpose, and particularly so if the specific causes of LUFG can be better identified and measured. This type of disaggregation comes with its own challenges, however, as noted by a study prepared for AGA on calculating GHG emissions from distribution systems: "Attempts to estimate leakage for pipeline systems using available information such as [LUFG] data are bounded by issues associated with meter accuracy and the large volumes of gas throughput at a facility relative to the fugitive releases."[103] These issues are discussed in more detail below.

Causes of LUFG

PHMSA states that there are at least 17 potential causes of LUFG, depending on the unique characteristics of each gas distribution system and its customers.[104] These causes can be broadly grouped into two categories: those stemming from leaks and those from measurement.[105]

Leaks are important from economic, safety, and environmental perspectives. As described previously, they can be detected through a variety of methods, and operators often use more than one technique to increase the reliability of their leak detection programs. From an environmental viewpoint, leaks are particularly concerning because they can offset the climate benefits from increased natural gas production and use.

Measurement error can be influenced by a wide variety of factors, including temperature, pressure, meter accuracy, and timing of readings. PHMSA states that when gas is purchased at a "gate station"—where gas is sold from a supplier to the utility—it is normally corrected to a standard temperature and base pressure: 60°F and 4 oz.[106] For every 5°F change in temperature, and for each 2 oz. change above the base pressure, the gas volume is expected to change by about 1 percent. For example, cold winter temperatures of 30°F would lead to several percentage points of volume change; higher pressures of 8 oz. or 10 oz. would have a similar effect.[107] Therefore, if customer meter-readings are not automatically or manually corrected for these variables, a utility's LUFG value may be affected.

A related measurement factor is the variation in accuracy between gate station meters and customer meters. AGA notes that almost all residential and small commercial gas meters are of a less accurate type than those used at pipeline meter stations.[108] At the same time, the error of customer meters must remain within certain limits as determined by local and state regulators.[109] For example, Massachusetts[110] and Washington, D.C.[111] both require meter accuracy within ± 2 percent. In contrast, given that large volumes of natural gas are sold at gate stations, both the seller and the local utility have a strong interest in ensuring the high accuracy of these meters.[112] (However, PHMSA states that distributors often rely on the measuring equipment of the seller when making their purchases.)[113]

PHMSA indicates that the best way to test for inaccuracy in gas meters is to take a random sample of all meters being used, regardless of age. In this way, the average accuracy of the total meter stock in the distribution system can be determined, whereas testing only meters that are due for replacement will bias the sample toward older meters. PHMSA notes that if the overall error is significant, the operator may consider a shorter time period for regular meter replacement.[114]

A 2012 National Association of Regulatory Utility Commissioners (NARUC) presentation provides an example of an anonymous utility's meter testing program and results.[115] For this utility, testing found that out of a total of more than 13,000 meters, 1.5 percent of meters were more than 3 percent fast, while 2.8 percent of meters were more than 3 percent slow. The rest of the meters were accurate to within 3 percent. According to the presentation, it was also determined that there were problems with a certain brand of meters, so the utility created a program to systemically replace those meters with ones sourced from a different manufacturer.

In addition to the accuracy of measurements, the timing of measurements is also an important factor contributing to LUFG. For instance, some operators may read their customers' meters on a rotating basis throughout each month or over the course of several months, but have more detailed information on the gas they purchase and bring into their distribution systems. If the LUFG reporting period ends at the close of a month, some meters will not have been read for weeks or more, causing a mismatch between the amounts of gas measured into the system and the known volume that was sold during that time.[116]

Other potential causes of LUFG include line pack, altitude, unmeasured company use, and theft. The manner in which companies address these items and others will contribute to variation in their monthly LUFG values, as well as to the total LUFG that they report on an annual basis.[117]

Reporting LUFG

Methods to calculate LUFG can vary significantly by state (or sub-state entity) and by individual company. Given such differences, it is often difficult to make meaningful LUFG comparisons across companies or, in some cases, across reports filed by the same company. Generally, utilities do not quantitatively disaggregate their LUFG values by cause, though they may list possible contributing factors.[118]

Consider natural gas utilities in Pennsylvania as an example. In February 2012, the Pennsylvania Public Utilities Commission (Pennsylvania PUC), through its Gas Safety Division, conducted a study of LUFG in Pennsylvania and its impact on ratepayers within the state.[119] The study found that reporting of LUFG to the Pennsylvania PUC was required in at least three regular filings: two at the state level and one at the federal level. These reports vary in their definition of LUFG, the time period over which LUFG is calculated, and the system scope considered (production/gathering, transmission, distribution, and/or storage).

The federal filing—Form PHMSA F 7100.1-1—is submitted on an annual basis and is required for all natural gas distributors in the United States (including those in Pennsylvania).[120] Unlike combined reporting in some states, this form is for distribution systems only, as PHMSA collects information for other parts of the natural gas network separately. In its guidance for completing the form, PHMSA allows a number of "appropriate adjustments" for factors such 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."

The guidance notes that "gained" gas (that is, a negative LUFG percentage) should not be reported and instead directs companies to record zero in those cases. LUFG is calculated over a 12-month period ending June 30, and according to additional clarification from PHMSA, LUFG has always been collected over this period based on prior feedback in the 1970s regarding companies' fiscal years.[121]

In its study, the Pennsylvania PUC found substantial variations in LUFG across the two state reports and the federal report, even when comparing values for the same company. For example, out of the nine companies for which LUFG data are presented, only three have LUFG values that are consistent (within 1 percent) across the three mandatory filings in each year. The other companies calculated LUFG values that, at times, varied by several percentage points across different forms for a given year. In some cases, companies reported negative LUFG values.[122] These differences are at least partially attributable to the variations described above, namely: LUFG definitions, reporting time periods, and the system scope considered.

The Pennsylvania PUC study states that "overall, the exact impact of UFG on the ratepayers of Pennsylvania is unknown."[123] Given the data, however, it later remarks that "a lack of definition for [LUFG] trivializes the importance of minimizing lost gas," and in doing so, the PUC highlights the potential benefits of establishing a consistent LUFG definition for natural gas utilities across the state. According to the study, these benefits include incentivizing active management of LUFG and the future option to set LUFG goals.[124]

The report also suggests the potential to compare LUFG values across utilities, though it explicitly acknowledges that each distribution system is different and, as such, there is justification for different LUFG levels. The National Regulatory Research Institute (NRRI)—which aims to serve the decision-making capabilities of state utility regulators through the publication of research[125]—does not believe that LUFG values provide enough information to make such comparisons. NRRI instead suggests that each utility's LUFG be tracked over time (against itself), providing a benchmark that avoids comparisons among systems with potentially very different measurement technologies, weather, pipeline ages, and customer characteristics.[126]

Cost Recovery for LUFG

When considering the potential for cost recovery of LUFG, state utility commissions must balance customers' interests—in terms of the prices they pay—with utilities' need to recover their prudent costs.[127]

NRRI points out a number of LUFG aspects that contribute to the difficulty in using it as a performance benchmark. Most of these have been discussed above and include differing LUFG definitions, multiple LUFG causes, measurement error or the inability to measure certain causes, the unique characteristics of each distribution system, annual variability, and—for all of these reasons—difficulty in discerning LUFG patterns over time or in projecting LUFG values for the future.[128] Overall, perhaps the greatest challenge is determining the degree to which the level of LUFG can be lowered in a cost-effective way, and the degree to which it is uncontrollable.

As noted above, there are two main causes of LUFG: leaks and measurement error. Some utilities view the second category, and in particular the difficulties surrounding meters, as the critical component of LUFG. For example, in a December 2009 briefing of LUFG cost recovery mechanisms, AGA states that LUFG is "an accounting and ratemaking issue, not an operational issue."[129] The briefing adds that "lost and unaccounted for natural gas costs are caused by meter uncertainty; these costs vary with the amount of customer usage and with fluctuating commodity prices, all of which are outside the utilities' control."[130] From this perspective, the proportion of LUFG due to "physically lost" gas—from leaks, theft, or similar causes—is relatively low.

This position is not shared by all observers, however. NRRI states the following in a June 2013 study:[131]

> *"The general impression conveyed by some utilities is that they have no or little control over the level of [LUFG] gas. To the contrary, state commissions need to monitor [LUFG] gas and not assume that all [LUFG] gas is uncontrollable and reflects only measurement and accounting errors that pose no real problem requiring corrective action."*

Under 49 CFR Part 191, gas distributors calculate and report their LUFG to the PHMSA as a percentage of the total gas entering their system.[132] These data are publicly available on PHMSA's website and serve as an illustration of the wide variance in reported values, notwithstanding the differences in LUFG calculation methodologies mentioned previously. For 2013, data for more than 1,400 distributors are provided, and of those, approximately 31 percent present values of zero, about 65 percent report positive values less than 10 percent, and almost 4 percent present values of 10 percent or more.[133] In general, the greater the proportion of LUFG that is "physically lost" gas, the higher the effective gas price that customers pay. This increase may be small for individual customers, but in some cases would be much more significant if shouldered completely by the utility.[134]

The NRRI paper cites three reports—concerning LUFG in the states of Pennsylvania, New York, and Massachusetts—that provide estimates of LUFG costs to customers or data that can be used to calculate such costs. The estimates span a wide range: $25.5 to $131.5 million annually in Pennsylvania, $60 million annually in New York, and $40 million annually in Massachusetts. The report acknowledges that, aside from these examples, there is sparse data on the total costs of LUFG for customers.[135]

NRRI also conducted a survey of U.S. state utility commissions in January 2013 to identify the policies and practices used by these commissions to handle LUFG.[136] The survey identified a number of different ratemaking approaches; one of these—passing through LUFG costs in the purchased gas adjustment (PGA) mechanism—is allowed by almost all state commissions and, according to NRRI, is part of a recent trend to shift these costs "out of base rates and into the PGA mechanism."[137] This matches AGA's assessment in its 2009 briefing, which stated that "the vast majority of utilities recover [LUFG] through the PGA mechanism, or through in-kind gas."[138] The NRRI survey also found that although several commissions are concerned when LUFG increases from prior levels or jumps suddenly, only a few provide explicit incentives to reduce LUFG.[139]

Although some causes of LUFG may not be under utilities' control, NRRI provides a set of suggested actions that attempt to mitigate its potential sources. A sample of these actions is provided in Table 7.[140]

Table 7. Potential LUFG Causes and Suggested Actions

POTENTIAL LUFG CAUSE	SUGGESTED ACTION(S)
Pipeline leaks	• Continuous monitoring of leaks • Detailed leak surveys • Timely repair/replacement of at-risk pipelines
Measurement error	• Testing and calibration of meter accuracy • Replacement or maintenance of malfunctioning customer meters • Installation of automated meter-reading devices that compensate for differences in temperature and pressure • Improved quality of data
Accounting error	• Well-defined standard practices • Periodic internal audits • Staff-training
Company use	• Measurement and exclusion of company use from LUFG
Third-party damage	• Proactive program to inform the public • Charges to the guilty party for gas losses and for pipeline repairs • Strict penalties enforced by the appropriate government agency
Cycle billing	• More frequent meter-reading • Less accounting lag
Inactive meter consumption	• Turning off meters when properties are vacated • Installation of automated meters
Stolen gas	• Inspection of meters for signs of tampering and follow-up investigation • Strict penalties for identified theft
"Blowdown"	• Inject "blowdown" gas into low-pressure mains by adding piping from compressors to the mains

It is important to note that, although these actions have the potential to reduce LUFG, the extent to which they do so—and therefore their cost-effectiveness—would be quite difficult to determine without a quantitative breakdown of LUFG causes. One particular challenge in this context is the accuracy of customer meters. For example, Massachusetts law allows for the use of meters with measurement error of up to 2 percent; on its own, this error could (theoretically) account for almost all reported LUFG.[141] As such, a strategy to address LUFG would likely need to include a component that considers customer meters as well.

In all, some observers have indicated that current LUFG cost recovery practices could be revisited, with an eye to clarifying some of the most pertinent uncertainties described above. More specifically, it may be beneficial to better quantify the causes of LUFG and thereby determine the extent to which LUFG costs are controllable,[142,143] to revisit the question of who should pay for LUFG costs,[144] and to consider programs or caps (such as those in Pennsylvania and Texas) that might incentivize utilities to reduce their LUFG percentages.[145] A better understanding of LUFG, and efforts to improve it, could be part of broader strategy to reduce methane emissions from natural gas distribution systems.

Policy Mechanisms for Pipeline Replacement

A robust natural gas pipeline system is important for a variety of safety, reliability, and environmental reasons. As discussed above, one of the greatest environmental motivators is the drive to capture the full climate benefits of increased natural gas production and use, which is served in part by reducing methane emissions from natural gas transportation infrastructure. Although pipeline replacement may not be economically justified for emissions reductions alone—at least at the current time—these reductions are surely a co-benefit of replacements conducted due to safety and reliability concerns.

There are several approaches to incentivizing the replacement of critical, at-risk natural gas pipelines for the achievement of these goals. These include cost recovery through rate cases, as well as alternative approaches, such as infrastructure cost trackers and base rate surcharges.[146] In general, solutions to replacement challenges will vary based on the individual operators, systems, and utility commissions involved.

Governmental and other organizations have reiterated the need for pipeline investment. In 2011, the U.S. Department of Transportation and PHMSA developed a Pipeline Safety Action Plan to "accelerate rehabilitation, repair, and replacement programs for high-risk pipeline infrastructure."[147] Similarly, NARUC issued a resolution on July 24, 2013, that:[148]

- Calls on regulators and industry to consider programs to quickly replace the most vulnerable pipelines while adopting rate recovery mechanisms to address utilities' financial realities;
- Directs state commissions to explore alternative rate recovery mechanisms for pipeline modernization, replacement, and expansion; and
- Encourages members' dialogue with all relevant stakeholders, including the public.

Natural gas operators may also be able to pursue GHG emissions reduction strategies other than pipeline replacement, such as the cost-effective technologies and practices recommended by EPA's Natural Gas Star Program.[149] These cover a broad spectrum, including technologies related to compressors/engines, dehydrators, pneumatics/controls, tanks, and valves, as well as suggested practices for inspection, testing, maintenance, and repair. The capital costs for these projects range widely (up to $50,000 or more), though many are described as requiring $1,000 to $10,000 or less.[150] A report authored by EPA's inspector general points out that although the program has been successful in reducing methane emissions from some parts of the industry, it has had limited success in the distribution sector due primarily to financial and policy barriers.[151]

Overall, with ongoing research and data collection, operators and regulators will continue to identify the best and most cost-effective mitigation options to reduce natural gas transportation systems' GHG emissions.

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