



The INGAA Foundation, Inc.

**A COMPARATIVE ANALYSIS:
METHANE EMISSION STUDIES OF
NATURAL GAS INDUSTRY OPERATIONS**

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EXECUTIVE SUMMARY

Greenhouse gas (GHG) emissions are a major concern of environmental advocates and policymakers. Since methane is the primary component of natural gas, rising U.S. production from the rapid development of shale gas has caused an increased focus on methane emissions associated with natural gas production, transportation and consumption. One result of this increased attention is an evolution of research and analysis responding to general and specific inquiries regarding methane leakage from natural gas operations from the wellhead to the burner tip. Researchers have published several waves of papers on the topic since 2011. This paper presents a literature review of primary papers issued in the past five years.

Generally, these studies compared emission estimates for the entire natural gas value chain with EPA estimates published in the annual GHG inventory report. Only recent studies have revisited sector-specific methane emission estimates that date to the 1990s. For example, a 2015 paper includes new emissions measurements for natural gas transmission and storage operations.

- In 2011 and 2012, life-cycle analysis studies reached a variety of broad conclusions. These studies did not introduce new emission data but instead relied on data from the 1996 Gas Research Institute-Environmental Protection Agency report¹ and other limited sources such as EPA's Natural Gas STAR program.² Conclusions from these "bottom-up" studies generally were driven by assumptions used in the analysis, and in many cases, these assumptions were not supported. Some studies concluded that methane emission estimates from natural gas operations were significantly under-estimated.
- A second wave of papers in 2012 and 2013 primarily explored methane inventory estimates based on atmospheric measurements. Significant uncertainties are inherent in these "top-down" studies due to the inability to attribute the methane measured to natural gas operations, and extrapolation of short duration (e.g., hourly) measurements to a regional annual inventory.
- Papers in 2014 largely assimilated the available literature and broadly acknowledged that *significant gaps* in data limited the ability to resolve the differences highlighted by the earlier studies. 2014 studies coined the term "superemitter" in reference to relatively rare, but large leak sources that result in a skew or "fat tail" in emissions distributions. The authors of these studies collectively agreed that significant data gaps needed to be addressed to understand better both nominal emissions and the contribution of these large emission sources.
- Several recent publications use new data that became available in 2014 and early 2015. This includes recent publications from collaborative projects involving the Environmental Defense Fund (EDF), academic institutions and industry that are providing new measurement data and methane inventory estimates from the natural gas sectors. Data are also available from measurements of natural gas operations reported to EPA under Subpart W of the EPA GHG Reporting Program (GHGRP)³

¹ *Methane Emissions from the Natural Gas Industry*. EPA and GRI (1996). This 15-volume compendium of reports from an EPA/GRI study is available at EPA's website at <http://www.epa.gov/gasstar/tools/related.html>. For example, the summary Technical Report (Volume 2): http://www.epa.gov/gasstar/documents/emissions_report/2_technicalreport.pdf

² The Natural Gas STAR program is an EPA voluntary methane reduction program with oil and natural gas companies. Information is available on EPA's website at: <http://www.epa.gov/gasstar/>

³ GHGRP reports are available through EPA's Facility Level Information on GreenHouse gas Tool (FLIGHT). See: <http://ghgdata.epa.gov/ghgp/main.do>

- Several 2014 review publications acknowledged significant data gaps, and recommended a combination of top-down and bottom-up approaches to improve and verify emission estimates. Recommendations included enhanced data collection utilizing sensors on equipment sites, mobile monitoring schemes, and regional atmospheric monitoring on an ongoing basis.

This could dramatically increase the understanding of methane emission sources. However, pursuing this strategy would require considerable resources over a number of years.

One consistent conclusion among all contributors, independent of the type of study or the year of its release, is that more direct data measurement is required. The more current studies focus on understanding and addressing data gaps through data acquisition, reassessing emission factors with contemporary measurements, understanding regional differences, and acquiring more data to understand and eliminate the skew attributed to superemitters.

1.0 INTRODUCTION AND BACKGROUND

Greenhouse gas emissions are an increasing concern. Although carbon dioxide (CO₂) is the most prevalent GHG emission, methane emissions are a significant concern because methane has a higher global warming potential (GWP) than CO₂, and this effect is amplified when considered over shorter time frames. Since methane is the primary component of natural gas, rising U.S. production from the rapid development of shale gas has caused an increased focus on methane emissions associated with natural gas production, transportation and consumption.

When natural gas is burned, it has a CO₂ emission advantage relative to other fossil fuels, but this burner-tip advantage is lessened by leaks and venting along the supply chain. Contemporaneous with shale production sparking interest in methane leakage, state and federal agencies began to develop regulations and policies to assess GHG and methane emissions levels and consider mandatory emission reductions. This interest has resulted in a series of publications on natural gas industry methane emissions from 2011 to the present. The authors of these studies and reports, using various datasets and methodologies, often reached markedly different conclusions.

This paper presents a literature review of primary papers published in the past five years. Methane emission estimates developed using different methodologies are compared and contrasted. Methodologies include site-based “bottom-up” estimates that use equipment and component-level emission factors and direct measurements, and “top-down” estimates based on atmospheric measurements.

Initial publications were largely academic research evaluating the methane impacts of shale gas production. This research attempted to answer preliminary and varied questions, such as:

- How much methane is emitted in the life cycle of shale gas?
- How do these emissions differ from “conventional” gas?
- How do these emissions compare with emissions from coal?
- What is the best way to measure methane emissions directly?
- How do different types of measurements affect estimation methodology?
- How accurate are the estimates?
- What is the scientific basis for estimates and comparison?
- Can emissions be characterized using discrete air samples?
- Can findings be extrapolated and averaged?

The specific motivating question(s) addressed by the researchers shaped their reporting and, in some cases, their conclusions. The body of this paper presents a brief systematic comparison of the referenced papers, including a discussion of life-cycle analysis, atmospheric sampling, reconciliation of bottom-up and top-down estimates, and the implications of large leaks (or superemitters). The papers have varied and evolved since the first wave of publications in 2011, as discussed in Sections 2 through 5. Appendices include a list of references that identify the papers reviewed (Appendix A) and an overview of key nomenclature and terminology common in the methane studies reviewed (Appendix B).

- Section 2 discusses initial papers in 2011 and 2012, which attempted to compare emissions from “unconventional” shale gas to conventional production, and to examine the existing

methane emission factors (EFs) and emission inventory implications. Several papers estimated natural gas system losses several times higher than estimates in the annual EPA National GHG Inventory (GHGI), and questioned whether the burner-tip GHG advantage of natural gas over other fossil fuels was lost due to natural gas leaks and venting.

- Section 3 discusses a second wave of papers in 2013, which further explored and revealed the difficulties in finding applicable methodologies and reaching consistent conclusions. These papers addressed the collection and analysis of atmospheric data as well as an analysis of data directly measured from production sites.
- As discussed in Section 4, a third wave of papers in 2014 and early 2015 attempted to assimilate the literature. The tone of the publications moved toward clarification, consolidation and identification of key issues regarding methodologies, leakage sources, and data reconciliation. These papers generally acknowledge that significant data gaps remain, note simple and unverifiable assumptions in earlier papers, and/or present atmospheric and direct measurements that begin to fill data gaps and indicate potential solutions. These papers also identify common skew or bias in reported results due to regional effects, reporting rules, and individual large leaks (recently termed “superemitters”).
- Section 5 includes additional discussion on large leaks, or “superemitters,” and the importance of understanding the frequency, size and factors that contribute to these key methane sources that may comprise a significant portion of the methane emissions inventory.

Sections 2 through 4 include a tabular list of the related papers reviewed and discussed in this literature review. The complete citation for each of those papers is in Appendix A: References. In addition, footnotes throughout this document cite other relevant references.

2.0 LIFE CYCLE ASSESSMENT STUDIES AND INITIAL ATMOSPHERIC MEASUREMENT STUDIES (2011 – 2012 PUBLICATIONS)

2.1 Introduction and Background

Papers published in 2011-2012 focused on life-cycle assessments in an attempt to understand whether natural gas leaks and venting offset the burner-tip advantage of natural gas compared with other fossil fuels. Life-cycle assessments attempt to quantify emissions from the point of production through end use and include all emissions that result from direct and indirect operations. The specific question(s) addressed by the researchers shape their reporting and appear in some many cases to shape their conclusions. The papers generally compared the results of this analysis with methane estimates published annually in EPA’s national inventory. This is shown below in the tables that summarize study findings.

In the sections that follow, the institutional affiliation of authors is selectively discussed to demonstrate the range of disciplines engaged in methane studies. Throughout the following sections, the paper citation identifies the primary author and year of publication. Appendix A provides complete citations to the referenced papers.

The 2011-2012 papers include Howarth (2011) followed by a response by Cathles (2012), Jiang (2011), Burnham (2012), Alvarez (2012), and Petron (2012), followed by a response by Levi (2012). The conclusions reached by these papers are briefly summarized in Table 1. This first wave of

papers compared methane emissions from new, “unconventional” natural gas production (i.e., the production of shale gas using hydraulic fracturing) with existing, “conventional” production. In addition to the life-cycle analysis studies, an initial atmospheric study was published in this timeframe.

The EPA GHGI is an annual report that has been prepared since the mid-1990s that estimates GHGs from all U.S. sources, including methane emissions from natural gas systems. The vast majority of methane emission estimates for natural gas operations are based on emission factors from a 1996 report by EPA and the Gas Research Institute. The April 2014 EPA GHGI, which reports 2012 emissions, estimates that about 1.4 percent of natural gas produced is lost from leaks and vents. At this leakage rate, natural gas has a lower GHG footprint than coal or oil. The 2011-2012 papers varied in their conclusions, with some papers indicating natural gas losses several times higher than estimates in the annual EPA GHGI, and concluding that the burner-tip GHG advantage of natural gas was lost due to significant natural gas leaks and venting. In some cases, the papers used a different reference Global Warming Potential – i.e., a higher GWP based on a 20-year time horizon rather than following EPA and international convention that uses a 100-year time horizon for GHG reporting and conversion to CO₂e emissions.

Methane emissions during the life cycle of shale gas production received significant attention in the scientific and environmental community following the 2011 letter by Howarth, Santoro and Ingraffea of the Department of Ecology and Evolutionary Biology at Cornell University published in *Climatic Change*. Howarth (2011) concluded that 3.6 -7.9 percent of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. They further suggested that the higher emissions occur during hydraulic fracturing, specifically during flow-back and drill out. Within months, a response was published in the form of a commentary by Cathles, Brown, Hunter and Taam of the Department of Earth and Atmospheric Science and Department of Chemical and Biological Engineering at Cornell University and Electric Software, Inc., respectively. Cathles (2012) argued that the Howarth analysis was seriously flawed due to an overestimation of fugitive emissions, an undervaluation of technology used to reduce emissions (i.e., “reduced emission completions” for wells with hydraulic fracturing), an irrelevant basis for comparison (heat vs. electricity), and the choice of GWP timeframe. Cathles (2012) concluded that the GHG footprint of shale gas is one third to one half that of coal, similar to EPA’s estimate.

A contemporary publication by Jiang (2011) from the Civil and Environmental Engineering Department, Tepper School of Business, and Department of Engineering and Public Policy at Carnegie Mellon University in *Environmental Research Letters* estimated that the life-cycle emissions from the Marcellus Shale are comparable to conventional gas and EPA estimates. This paper highlighted the significant uncertainty in the Howarth emissions estimates due to long-term production volumes and variability in flaring, construction and transportation. For example, comparing a well producing 0.3 MMscf/day with a five-year lifetime to a well producing 10 MMscf/day with a 25-year lifetime showed that the estimated emissions ranged from 0.1 to 9.2 g CO₂e/megajoule, a 100-fold difference.

Researchers at The Center for Transportation Research at Argonne National Laboratory published an article comparing life-cycle emissions of shale and conventional natural gas to coal and petroleum in *Environmental Science & Technology*. Burnham (2012) drew attention to the wide variation in the published emissions estimates for methane in shale gas production [Howarth (2011), Jiang (2011)] and examined the uncertainties involved in calculating the life-cycle impacts

of key methane emissions sources. Using a transportation end-use model, Burnham identified data gaps in methane emissions for well completions and liquid unloadings, and concluded that shale and conventional natural gas emissions are comparable, and are less than petroleum and coal.

Significantly, the 2011-2012 papers relied on previously published information on emissions to formulate estimates. No new or original emissions data informed these papers.

The 2011-2012 papers represented a variety of perspectives as might be expected given the wide range of expertise and practical experience among the authors. These included researchers from national labs, industry and academia. Among the academics, departmental affiliations included ecology and biology, chemical and biological engineering, earth and atmospheric science and business.

Table 1. Publications (2011-2012)

Study	Type ^A	Comparison of Technologies	Comment on Factors	Conclusion of % Leakage ^B
Howarth (2011)	LCA	Shale gas 20-50 percent greater emissions than coal on a 20-year GWP and equivalent to coal on 100-year GWP	EPA underestimates emissions	Shale= 3.6-7.9 percent Conventional= 1.7 – 6 percent
Cathles (2012)	Response to Howarth	Shale gas emissions less than 0.5 to 0.33 Coal	EPA correctly estimates emissions	1.6 percent
Jiang (2011)	LCA	Shale Gas ≈ NG Shale Gas < Coal for Electricity	EPA correctly estimates emissions	2.4 percent
Burnham (2012)	LCA	Shale Gas ≈ NG < Petroleum < Coal	EPA correctly estimates emissions	Shale= 1.9 percent Conventional= 2.6 percent
Alvarez (2012)	Proposal for Technical Analysis	Introduces Technology Warming Potential to apply to decision making	N/A	N/A
Petron (2012)	ATM - regional Colorado	N/A	EPA underestimates emissions	2.3 – 7.7 percent
Levi (2012)	Response to Petron	N/A	EPA correctly estimates emissions	N/A

^A Types of Studies: Life-Cycle Analysis (LCA); Atmospheric Measurements (ATM)

^B Inventory results are often presented as a percentage of natural gas production lost prior to its end use. This is generally based on annual “marketed production,” as reported by the U.S. Energy Information Administration (EIA), as the denominator. EIA information is at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm. The EPA-GRI report estimated this as 1.4 percent (± 0.5 percent). The EPA National Inventory (April 2014 report of 2012 emissions) estimated this as 1.3 percent (+0.4, -0.3 percent). The natural gas losses, along with assumptions regarding the global warming potential of methane and the efficiency of the end use application, provide an indication of whether natural gas losses offset its burner tip advantage relative to coal or other fossil fuels. The percentage where system losses exactly offset this advantage is referred to as the “break even” percentage.

2.2 Current State of Knowledge – Life-Cycle Assessment Data Gaps and Recommended Actions

Based on an in-depth study of eight peer-reviewed life-cycle assessments, a report authored by researchers at the National Renewable Energy Laboratory (Heath (2014)) presented the attributes of life-cycle analysis that are critical to interpreting the results of such assessments. This report includes a substantive list of the data needed to improve life-cycle analysis and reduce the uncertainty inherent in the 2011-2012 papers. The list of attributes and recommendations is telling, because it clearly demonstrates that the authors of 2011-2012 life cycle analysis papers suffered from a paucity of data and that this affected significantly the conclusions of their analysis. The attributes from Heath (2014) include:

1. **Gas Type:** This includes the type (shale, tight, coalbed methane, etc.), the play or set of plays (different plays—or geologic formations in a given geographic area—have different lifetime production and composition), selection of baseline years, and selection of emission factors (shale specific vs. other unconventional, conventional).
2. **Modeling Philosophy:**
“Longitudinal studies” develop a model of activities for a typical well (or set of wells) and then sum emissions across all activities to achieve an estimate of emissions per unit of final product.
“Cross-sectional studies” use emissions representative of all wells in a given geographic area at all stages of their lives and then divide by annual gas production to estimate the emissions.
3. **Comparison:** Life-cycle analyses seek to inform decisions through comparison; however, the basis of comparison (e.g., specific conventional sources, defined mixtures of conventional gas types, unspecified mixtures of conventional gas types, etc.) can vary significantly.
4. **Units:** The choice of functional unit for comparison, e.g., megajoule of fuel energy content or kilowatt hour-delivered electricity.
5. **Global Warming Potential time horizon and index value:** The range of GWPs was 25-33 for the 100-year horizon and 72-100 for the 20-year horizon. GWP of 30 over a 100-year horizon was selected for harmonization purposes in the Heath paper.
6. **Power Plant Thermal Efficiency:** The assumed efficiency presented in the reviewed papers range from 43 percent to 50 percent on a higher heating value basis. However, to reflect a modern combined cycle plant, the Heath paper selected 51 percent for the harmonization exercise.

The harmonization exercise aimed to establish analytically consistent comparisons reflecting the latest knowledge on emission-producing activities. Although variability remained due to the factors mentioned above, the NREL authors concluded:

“...we find that per unit electrical output, the central tendency of current estimates of GHG emissions from shale gas generated electricity indicates *life-cycle emissions less than half those from coal and roughly equivalent to those from conventional natural gas.*”
[Emphasis added]

In addition, a sensitivity analysis that considered factors such as production over the well lifetime (referred to as the “estimated ultimate recovery” (EUR) of wells) led to the conclusion that,

“...estimates of life-cycle GHG emissions from the use of shale gas for electricity generation are *most sensitive to emissions from the regular unloading of liquid from wells and estimates of well lifetime production (EUR).*” [Emphasis added]

As part of ongoing efforts to measure and report methane leakage accurately, the authors identify a number of data gaps and information needs, which would require significant ongoing efforts to fulfill. These included the following recommendations:

1. Confirm the analysis and conclusions from studies through verified measurements of emissions from components and activities throughout the natural gas supply chain.
2. Perform robust analyses of lifetime well production and the prevalence of practices to reduce emissions.
3. Select sampling and data collection plans to reflect the diversity across the industry and repeat in a timely manner to remain relevant as the industry evolves.
4. Perform a robust characterization of the upper end of distribution of emissions, termed “superemitters” by the authors.
5. Verify bottom-up, component level emission estimates with top-down atmospheric sampling.
6. Include natural gas used for transportation and heating in life-cycle analyses by measurements at the points of leakage that differ from its use for electricity generation.

These recommendations indicate that a more solid foundation is needed for life-cycle analyses, including: significant additional data to provide an adequate basis for such estimates; systematic programs to develop the data; and, the use of different methods to verify results.

3.0 ATMOSPHERIC STUDIES: 2012-2013 PUBLICATIONS

3.1 Introduction and Background

A second wave of publications in 2012-2013 focused on the collection and analysis of atmospheric data and on analysis of data directly measured at production sites. The production site study was the first of many collaborations between the Environmental Defense Fund (EDF), academia and industry. The ongoing EDF-industry studies include new measurements at natural gas industry facilities.

The 2012-2013 papers, summarized in Table 2, included Peischl (2013), Miller (2013), Karion (2013), and Allen (2013).

Table 2. Publications (2013)

Study	Type	Comment on Factors	Conclusion of % Leakage
Peischl (2013)	ATM - regional Los Angeles	EPA underestimates emissions	17 percent
S.M. Miller (2013)	ATM - national	EPA underestimates emissions	3.6 percent
Karion (2013)	ATM - regional Utah	EPA underestimates emissions	6 – 12 percent
Allen (2013)	Production: Direct Measurement	EPA correctly estimates emissions	0.42 percent (for production sector)

A pilot study published in the *Journal of Geophysical Research* by Petron (2012), affiliated with National Oceanic and Atmospheric Administration in Boulder, stimulated discussion and rebuttal with respect to atmospheric studies of hydrocarbon measurements. The pilot study sought to test a new measurement strategy for characterizing emissions at a regional level. Researches collected data from measurements made at both a single 300-meter tall tower and from automobile-based on-road air sampling. They then compared these atmospheric measurements with bottom-up emissions estimates from the Western Regional Air Partnerships emissions inventories. Using molar ratios of propane to methane (i.e., propane is a “chemical marker” that correlates methane measurements to natural gas operations rather than propane free methane sources), the concentration of each species in the atmospheric measurements was derived and compared with bottom-up estimates for the suspected sources. Petron (2012) concluded that the methane leakage from natural gas operations in the region is significantly greater than indicated by the bottom-up estimates.

A comment on the Petron (2012) study was published in late 2012 by Michael Levi, affiliated with the Council on Foreign Relations. Levi (2012) argued that the Petron estimates relied on unfounded assumptions about the composition of vented natural gas. He further used data from Petron (2012) to calculate a new set of estimates that were consistent with existing EPA inventories. Petron later agreed that the composition estimates were based on unfounded assumptions. The initial Petron study and Levi studies are summarized in Table 1.

Other regional studies such as the Uintah County, Utah study by Karion (2013), affiliated with NOAA in Boulder, and the Colorado Denver-Julesburg Basin study by Petron (2014), used a mass-balance approach, which attempted to relate atmospheric measurements to emission inventory estimates from natural gas operations and other sources of methane. While the study technique was not disputed, many questioned the ability to extrapolate a day or two of data to an extended period of time (e.g., annual emissions), or a single geographic location to an entire region or to a national level.

Peischl (2013), affiliated with NOAA in Boulder, used two months of atmospheric data, in the form of CH₄/CO and CH₄/CO₂ ratios, measured throughout the Los Angeles Basin, which were then compared with bottom-up state inventories. Peischl determined that “the atmospheric data are consistent with the majority of methane emissions in the region and attribute the biggest contributions to fugitive losses from natural gas in pipelines and urban distribution system and/or geologic seeps, as well as landfills and dairies.”

Miller (2013), from Harvard University, published a study to estimate the spatial distribution of methane sources in the United States. Using data from 2007-2008 NOAA observations, atmospheric transport modeling, and a method called geostatistical inverse modeling, the study concluded that official inventories underestimate methane emissions nationally, citing specifically the animal husbandry and fossil fuel industries.

These papers paved the way for more recent work to refine the methodologies of study design and analysis.

3.2 Current State of Knowledge and Recommended Actions – Atmospheric Studies

Peischl's 2015 study examined the Haynesville shale region in eastern Texas and northwestern Louisiana, the Fayetteville shale region in Arkansas, and the portion of the Marcellus shale region in northeastern Pennsylvania. Together, these fields represented 20 percent of June 2013 U.S. natural gas production. In contrast, earlier regional studies represented less than 1 percent of natural gas production for a given month [Petron (2012), Karion (2013), Peischl (2013)].

Peischl (2015), like Karion (2013) and Petron (2014), collected atmospheric methane samples and used methane flux to estimate emissions. Peischl compared the one-day methane emissions for each region with the total volume of natural gas extracted from that region within the same month. Peischl estimated the loss rates at 1.0 to 2.1 percent for the Haynesville region, 1.0 to 2.8 percent for the Fayetteville region, and 0.18 to 0.41 percent for the Pennsylvania-Marcellus region. These loss rates are less than previously published values for atmospheric measurement based estimates, and on the order of the 0.42 percent loss rate reported by Allen (2013) when he directly measured emissions from hundreds of wells across the U.S.

Peischl (2015) noted that although the absolute magnitude of methane emissions was similar to estimates from previously published atmospheric measurements, *relative* loss rates (i.e., percent of production) were significantly lower because of the substantial natural gas production rates in these shale plays. Higher production efficiency from improved technology and variations in fossil fuel composition were likely explanations for the lower estimates in the 2015 study.

Peischl (2015) included the following recommendations:

1. Repeat measurements and challenge the applicability of one-day methane emissions rates as representative for the region.
2. On a regional basis, for a given formation, determine whether the methane emission rates change over the full life cycle of production.
3. Understand the drivers behind regional differences in loss rates.

4.0 RECONCILING TOP-DOWN AND BOTTOM-UP ESTIMATES

A review of life-cycle assessment and atmospheric studies reveals a common quest to compare results against historical information such as the EPA GHGI, and to reconcile the measurements and emission estimates of bottom-up (source-based) methods with the measurements and estimates of top-down based methods. A “third wave” of papers in 2014 attempted to reconcile the differences in conclusions, methodologies, reporting units and basic assumptions. These papers, presented in Table 3, include Brandt (2014), McGarry (2014), Heath (2014) and Allen (2014). For the Brandt paper, the table compares technologies, and comments on emissions and leakage. A summary of study conclusions is provided for the other three papers.

Table 3. Reviews (2014)

Study	Type	Comparison of Technologies	Comment on Factors	Conclusion of % Leakage
Brandt (2014)	Literature Review NG Leaks (1996-2013)	100-year GWP supports coal-to-NG substitution	EPA underestimates emissions	Superemitters could be responsible for a large fraction of leakage
				Regional atmospheric studies unlikely to be representative of typical
Summary of Study Conclusions				
McGarry (2014)	Literature Review NG Leaks (2010-2014)	This paper presents a systematic summary of each paper under review. The three primary issues addressed by the papers are: 1. Bottom-up, Top-down reconciliation 2. 20-year or 100-year GWP 3. More direct measurement data required from all stages of life cycle		
Heath (2014)	Harmonize LCA studies	Shale Gas Emissions \approx Conventional Natural Gas and 50 percent of emissions from coal for electricity		
Allen (2014)	Reconcile Bottom-up and Top-down	Difficulty in reconciliation are a result of 1. Large population of sources; 2. Different measurement and estimation approaches; 3. Extreme values of emission rates for certain sources (“fat-tail” distribution; referred to as “super-emitters” in other 2014 papers)		

Brandt (2014) reviewed 20 years of technical literature on natural gas emissions in the United States and Canada in an effort to summarize and compare the published estimates from both bottom-up and top-down studies. The paper addressed the topic using a question-and-answer format. Examples below show questions from the paper and a paraphrased summary of responses:

Q. “Why might emissions inventories be under predicting what is observed in the atmosphere?”

A. Current inventory methods rely on key assumptions that are not generally satisfied.

1. Devices sampled most likely are not representative of current technologies

(For example, hydraulic fracturing and horizontal drilling were not widely used in the 1990s when the EPA emission factors were first established. In contrast to this, recent gas production efficiencies occur through improved technologies and state-of-the art practices e.g., reduced emission well completion, which are thought to reduce loss rates [Peischl (2015)]).

2. Measurements to generate emission factors are expensive and therefore sample size is inadequate and bias likely results.
3. “Heavy-tail” or “fat-tail” emissions distributions or “superemitter” sources are suspected to dominate emissions. Studies generally have small sample sizes and likely under estimate emissions from these sources (e.g., a superemitter is not found due to the limited sample size).
4. Activity and device counts used in inventories are not well understood. Examples include contradictory and incomplete estimates. Thus, it is not known if equipment counts are representative of actual operations.

Q. “Does evidence suggest possible sources of excess methane emissions relative to official estimates within the natural gas sector?”

A. In order to address this, the authors estimated emission ranges of select sources within the natural gas sector, as well as sources that could be mistaken for natural gas emissions. They concluded that there is a poor understanding of sources of “excess methane” reported in some atmospheric studies. However, they assert that hydraulic fracturing is *unlikely* to be a dominant contributor to total emissions and that other sources, such as abandoned oil and gas wells and geologic seeps, may contribute to disparities in emission estimates.

Q. “How can management and policy help address the leakage problem?”

A. Practical and potentially economically profitable solutions are being identified, such as:

1. Leak detection and repair programs, which are profitable for sectors that own the gas.
2. Developing methods to identify and fix high-emitting sources rapidly.
3. Improving inventories through characterization of emissions distributions and incorporating new knowledge to improve the understanding of key sources.
4. Performing device-level measurements at facilities of a variety of designs, vintages, and management practices and pairing these studies with additional atmospheric science studies to close the gap between top-down and bottom-up studies.

These discussion topics are similar to questions and recommendations that have persisted since methane emissions characterization was initiated over two decades ago. Until recently, little new emissions or measurement data had been collected since the GRI-EPA report was published in 1996. The conclusions acknowledge that significant data gaps remain, and measurement programs and projects are needed to resolve questions.

In 2014, *Current Opinion in Chemical Engineering* published a review article by David T. Allen entitled, *Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements*. Allen identifies known problems of each reporting method, and recommends a combination of top-down and bottom-up approaches to improve emission estimates. Allen noted that the combination approach worked for other industries, including automotive, where researchers identified super-emitting motor vehicles. Based on analogies from the automotive

sector, Allen offers a multi-pronged approach to identify super-emitters and reduce emissions in the natural gas industry. For example,

1. Similar to “on board diagnostics” currently required for automobiles, build smart sensing devices into well pads, compression stations, etc. to monitor key process variables and signal for further analysis and testing when defined bounds are exceeded.
2. Similar to highway monitoring to identify vehicles with high emissions:
 - a. Deploy mobile methane sensors to identify leaks (e.g., infrared (IR) on aircraft or monitors on ground vehicles), and
 - b. Strategically place ground or atmospheric monitoring stations to continually track regional impacts.

Using a combination of approaches on an ongoing basis can dramatically improve our understanding of methane emission sources, Allen concludes. Once sources are identified, companies can develop technologies (some already available) to reduce emissions. Still, like Brandt (2014), Allen concedes that significant resources, project design, and implementation time are necessary to pursue these recommendations.

The rapid growth of natural gas production from shale has spurred increasing interest in methane emissions and inspired the need for additional research. More recent publications are moving toward clarification, consolidation and identification of key issues regarding methodologies, leakage sources and data reconciliation, as shown in Table 4.

Table 4. Publications (2014-15)

Study	Type	Comment on Factors	Conclusion of % Leakage
Petron (2014)	ATM - regional Colorado	EPA underestimates emissions	4 percent
Peischl (2015)	ATM - regional, PA TX/LA, AK	EPA correctly estimates emissions	1 percent
Subramaniam (2015) Zimmerle (2015)	T&S Direct Measurement and National Estimate	EPA correctly or overestimates emissions	Super emitters responsible for a large fraction of leakage.
Mitchell (2015)	Gathering and Processing Direct Measurement	N/A	<1 percent
Lamb (2015)	Distribution Direct Measurement	EPA overestimates emissions	0.08 – 0.18 percent for the Distribution Sector (EPA estimate is 0.28 percent)

A path is beginning to emerge as researchers move toward filling information and data gaps, reducing uncertainties and forcing robust and rigorous analysis. In Petron (2014), the author provides alternatives to improve the approach in his previous paper [Petron (2012)] and acknowledges that the earlier pilot study relied on simple emission models with assumptions.

Peischl (2015), Subramanian (2015), Mitchell (2015) and Lamb (2015) all present atmospheric *and* direct measurements that begin to fill data gaps and help identify a “skew” or bias due to regional effects, regulatory criteria (e.g., GHG reporting rule deficiencies) and superemitters.

Subramanian (2015), Zimmerle (2015) and Lamb (2015) present results from collaborative EDF-industry projects. A series of such studies is developing new data for natural gas industry sectors. For transmission and storage (T&S), field measurements include direct facility measurements and related downwind measurements of plumes that include a tracer. The latter method is referred to as tracer flux measurements. Subramanian (2015) used direct measurements at the site level with concurrent tracer flux measurements to determine emission rates from T&S sector compressor stations. This study provides concrete measurement data to support analysis and conclusions. A second paper from Zimmerle (2015) published on-line in July 2015 extrapolated emissions to a national estimate for T&S using a model based on these site measurements and additional information available from study participants, the EPA GHGRP, and other sources.

The T&S study indicated that, at most sites, the direct measurements and downwind tracer flux measurements agreed within the experimental uncertainty associated with the methods (i.e., on the order of $\pm 20\%$). However, the tracer flux measurements were skewed more greatly because of two large leak sources that were not measured at the site due to safety concerns or other complications. Those two leaks were part of a measurement program that included 45 facilities and nearly 1,400 onsite direct measurements. The study model that extrapolated emissions to a national estimate indicates that large leaks accounted for nearly 25 percent of all methane emissions. The onsite measurements were skewed less, with 15 percent of the sites responsible for 50 percent of the cumulative emissions estimate. This provides an indication of how large leaks can affect the results of an analysis. Subramanian (2015) and Zimmerle (2015) recommend more direct emission measurements and more careful attention to several emissions sources either excluded from the GHGRP or under-estimated due to simplified GHGRP methods. For example, more appropriate emission factors for exhaust methane from reciprocating engines under Subpart C of the GHGRP would improve the methane emissions estimate.

In March 2015, Lamb (2015) published results of a study of emissions from the natural gas distribution sector. That study used an array of measurement methods to gather new data and project a national inventory for the distribution sector. The paper concludes that distribution emissions are significantly lower than the EPA estimates based on emission factors from the GRI-EPA report, and that there are significant regional differences attributable to the relative prevalence of newer plastic pipe versus older cast iron distribution mains and unprotected steel mains and service lines.

5.0 LARGE LEAK SOURCES OR “SUPEREMITTERS”

Several independent studies using direct measurements have found that a small number of “superemitters” are responsible for a large portion of methane leakage. An emissions distribution plot that includes a superemitter(s) will exhibit a “heavy tail” or “fat tail.” As such, the terms superemitter and fat tail or heavy tail are often used interchangeably to describe rare, but large, leaks. . Brandt (2014) cited 10 studies from 1997 to 2013, nine of which include direct

measurements that highlight the superemitter phenomenon. Brandt’s findings are consistent with results from 1990s methane leak surveys and the EPA Natural Gas STAR program.⁴

The studies addressing superemitters are summarized in Table 5. The key to interpreting this table is to understand the meaning of the percentages in the two right hand columns. For example, with Allen (2013), 44 percent of the leak sources contribute 90 percent of the overall emissions.

Table 5. Large Leak or Superemitter Results

Study Name	Measurement Technique	% of sources Contribute to...	% of emissions
Allen (2013)	Direct Measurement of Well Liquids Unloading	44 percent	90 percent
Alvarez (2012)	Analysis of Reported Emissions	10 percent	70 percent
Kang (2014)	Direct Measurement	16 percent	three orders of magnitude larger than the median flow rate
Subramanian (2015)	Direct measurement Site level and concurrent downwind tracer-flux (T&S)	10 percent	50 percent
Mitchell (2015)	Direct measurement Site level and concurrent downwind tracer-flux (G&P)	30 percent	80 percent
Chambers (2006)*	Down-wind differential absorption LIDAR	1 PRV leak	104 kg/hr - 450 kg/hr
Clearstone (2002)*	Direct measurement using Hi-Flow™ sampler	To 10 leaks in each facility	35.7 - 64.6 percent
Harrison (2011)*	IR camera, Hi-Flow™ sampler	1 leak (3 percent) (valve/flange)	five orders of magnitude larger than the emissions factor
NGML, Clearstone, IES (2006)*	Direct measurement using Hi-Flow™ sampler and optical methods	0.6 percent	58 percent
Picard (2005)*	Sampling via various methods	Top 10 leaks	80 percent
Shorter (1997)*	Remote sampling via tracer methods	Top emitters	Two to four orders of magnitude larger than the small emitters
Trefiak (2006)*	Optical measurement and Hi-Flow™ sample	23 percent	77 percent

* cited in Brandt (2014)

⁴ EPA Natural Gas STAR, Lessons Learned – Directed Inspection and Maintenance at Compressor Stations; see http://www.epa.gov/gasstar/documents/ll_dimcompstat.pdf

6.0 CONCLUSIONS

A number of confusing and contradictory reports on methane emissions from natural gas operations have been published since 2011 on methane emissions from natural gas operations. This literature review, which focused on the major reports, found:

- Many studies seek to assess natural gas losses to determine whether methane emissions from leaks and venting offset the burner-tip advantage of natural gas compared with other fossil fuels. Studies also compared “new” estimates with the EPA estimate from the annual GHG inventory.
- Studies include “bottom-up” estimates based on direct measurements of emission sources at facilities and “top-down” estimates based on atmospheric measurements of methane and other chemical markers that can provide a signature of methane from natural gas versus other methane sources.
- In 2011-2012, life-cycle analysis studies reached broad and differing conclusions. These studies did not introduce new emission data but instead relied on data from the 1996 GRI-EPA report and other limited sources such as EPA’s Natural Gas STAR program. Conclusions were generally driven by assumptions used in the analysis, and in many cases, these assumptions were unsupported.
- A second wave of papers in 2012-2013 primarily explored methane inventory estimates based on atmospheric measurements. Significant uncertainties are inherent in these studies because of an inability to assign the methane measured to natural gas operations, and the questions surrounding extrapolating short duration (e.g., hourly) measurements to an annual inventory.
- Papers in response to 2011-2012 life-cycle analysis papers and initial atmospheric studies identified the unsupported assumptions and analysis that shaped the results of those early papers.
- Subsequent papers in 2014 sought to assimilate available literature. These papers broadly acknowledged that gaps in data and information limited the ability to reach a conclusion on the differences in earlier studies. Authors collectively agreed that additional work, especially in closing data gaps, was necessary to understand emissions.
- New results are becoming available. These include recent publications stemming from collaborative projects between EDF and industry participants. This work, plus measurement data being reported to EPA under Subpart W of the GHGRP, is providing new *measured* data from the natural gas sectors.
- Authors recently introduced a new term, “superemitter,” which refers to relatively rare large leaks that are a primary contributor to overall emissions. Superemitters tend to skew emissions distributions. More data (i.e., more measurements) are needed to understand the prevalence and size of these emission sources.
- There are regional differences in loss rates, currently attributed to variations in the technology in service and the fossil fuel composition. Moreover, uncertainty exists in extrapolating emissions from a given region to a national inventory. Further studies to understand the drivers behind regional differences, and the rate of change of life-cycle emissions for a given formation are recommended.
- Authors recommend a combination of top-down and bottom-up approaches using enhanced data collection tools. These would include sensors on equipment sites, mobile monitoring schemes, and regional atmospheric monitoring on an ongoing basis. This could dramatically increase the understanding of methane emission sources. Pursuing such an endeavor would require considerable resources over a number of years.

APPENDIX A: REFERENCES
(Primary studies documents cited in Table 1 through Table 5)

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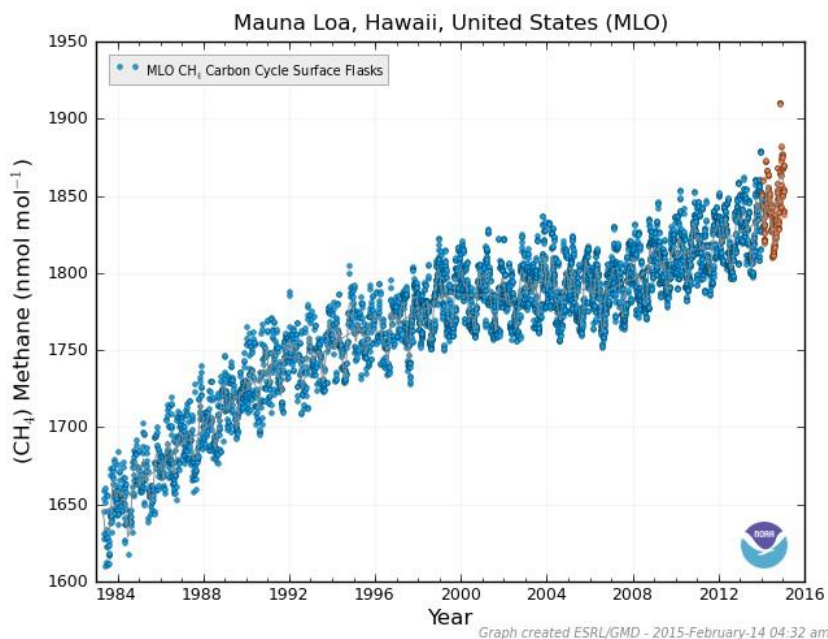
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APPENDIX B: KEY TERMINOLOGY FROM METHANE STUDIES

It is important to understand the terminology used in methane emissions studies. As part of this, it is important to distinguish between emissions that are quantified based on measurements and emissions calculated based on estimates and assumptions.

Examples of emissions and emissions sources that have been directly measured include NOAA's measurements of atmospheric methane that have been conducted since 1983 (Figure 1) and the measurement of emissions from pneumatic chemical injection pumps conducted by Allen and published in 2013.

Figure 1. NOAA Measurements of Atmospheric Methane 1983-2015⁵



Estimated values or parameters are not directly measured, but inferred or calculated based on assumptions. For example, global warming potential (GWP) is an index based on radiative forcing. Radiative forcing in watts per square meter (W/m²) is a computed value which estimates the effect of a given gaseous concentration change on the radiation of the atmosphere – i.e., the ability of the atmosphere to retain heat. Thus, GWP is inexact, which is a primary reason that GWP values for GHGs such as methane continue to be revised and updated. Another example of an estimate is the concentration of atmospheric methane prior to 1983. This is based on ice core theory and is dependent upon the accuracy of assumptions used to relate those measurements to the actual concentration present in the atmosphere at specific points in time. These are provided as examples of “estimated values,” and this topic is discussed because estimates, rather than measured values, are common in the literature on methane emissions from natural gas operations.

The majority of the methane leakage studies since 2011 are based on *estimates* that were created out of necessity to define a “value” that can be compared and contrasted with other studies and

⁵ <http://www.esrl.noaa.gov/gmd/dv/iadv/graph.php?code=MLO&program=ccgg&type=ts>

reported emissions. Many assumptions used in making these estimates result in uncertainty that contributes to disparate results from different studies. For example, radiative forcing is used in calculating GWP. Likewise, the GWP is used, along with emissions factors, to arrive at equivalency to carbon dioxide (CO₂e), which in turn is used to compare different types of GHG emissions. Assumptions associated with estimated values for each relevant parameter and within each step of the calculation and analysis process are primary causes of differing results for the studies reviewed.

A number of terms and principles common to the methane studies reviewed are included here to provide additional background.

KEY TERMINOLOGY:

Atmospheric Methane

As demonstrated by Figure 1, reports of the amount of methane in the atmosphere after 1983 are based on direct measurement while concentrations prior to 1983 are estimates based on assumptions. There is much reference in the literature to the atmospheric concentrations of various gases in the pre-industrial age, starting around 1750. Those values are estimates.

Radiative Forcing

A computed value, it is the change in the net (i.e., downward minus upward) radiative flux (expressed in W/m²) at the top of the atmosphere due to a change in an external driver, such as a change in the concentration of CO₂ or another GHG, or the output of the sun. This flux is computed by holding key atmospheric properties at fixed values and is further defined as the change relative to the year 1750.⁶

Global Warming Potential (GWP)

An index, measuring the radiative forcing following a pulse emission of a unit mass of a given GHG in the present-day atmosphere integrated over a chosen time horizon (*usually 20 or 100 years is used as the reference time horizon*), relative to that of carbon dioxide. The GWP represents the combined effect of the time that these gases remain in the atmosphere and their relative effectiveness in causing radiative forcing.⁷ Typically, GHG emissions are reported in units of carbon dioxide equivalent (CO₂e). Gases are converted to CO₂e by multiplying their mass emissions by their global warming potential (GWP).⁸ The different metrics provide the ability to consider effects that differ over time due to the atmospheric lifetime of a gas. Parties to the United Nations Framework Convention on Climate Change (UNFCCC) selected the 100-year time horizon as the basis for reporting. That standard is used for federal reporting programs, including the annual EPA GHG Inventory (GHGI) and the more recent mandatory GHG Reporting Program (GHGRP).

Studies often use the 20-year time horizon to highlight potential nearer-term implications associated with gases with shorter atmospheric lifetime (such as methane), where the GWP for the

⁶ Climate Change 2013: *The Physical Science Basis*

http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_AnnexIII_FINAL.pdf glossary

⁷ Climate Change 2013: *The Physical Science Basis*

http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_AnnexIII_FINAL.pdf glossary

⁸ <http://www.epa.gov/climateleadership/documents/emission-factors.pdf>

gas is higher when the time horizon is shortened. The time horizon assumed for GWP is a simple assumption that can significantly impact the results of an analysis. Choosing a 20-year or 100-year time horizon is a major contributor to differences in the conclusions reached by published papers.

Emission Factors and Activity Data

Emission Factors are a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).⁹ An emission inventory is developed from emissions factors along with the related activity data.

$$Emission_{pollutant} = Activity * Emission Factor_{pollutant}$$

where:

E = emissions, in units of pollutant per unit of time

A = activity rate, in units of weight, volume, distance, or duration per unit of time

EF = emission factor, in units of pollutant per unit of weight, volume, distance, or duration

GHG Emission Inventory¹⁰

These can be national or regional inventories prepared by government agencies to estimate GHGs emissions by source or sector for individual or cumulative GHGs. Examples include, on a national level, the EPA GHGI, and on a regional level, the California Air Resources Board (CARB) GHG inventory.

Bottom-Up

The term bottom-up refers to measurements of methane emissions, made directly at the emission device or facility level, that can be used to develop facility-level estimates and that can be rolled-up to create regional or national estimates of emissions for the natural gas supply chain. The goal in this approach is to measure emissions from a statistically representative sample of sources, and extrapolate to larger populations using emissions factors and activity data. For example, the count (or national estimate) of reciprocating compressors along with an emission factor for reciprocating compressors can be used to estimate emissions associated with compressor leaks and venting (e.g., unit isolation valve leakage). The measurements and extrapolation to larger populations are referred to as a “bottom-up” estimate, since the estimate relies on national or regional counts of sources and direct measurements of emissions from a sampling of the sources.¹¹ A key uncertainty associated with bottom-up estimates is whether there are enough contemporary direct measurements to provide a valid basis for extrapolation. In addition, the activity data (e.g., national count of the device in question) may not be well-defined. Therefore, estimates fill the data gaps for extrapolation to a

⁹ <http://www.epa.gov/ttn/chief/ap42/index.html>

¹⁰ GRI/EPA 1996 - GRI/EPA Reports, "Methane Emissions from the Natural Gas Industry"

¹¹ Allen, D.T., "Methane emissions from natural gas production and use: reconciling bottom-up and top-down measurements", *Current Opinion in Chemical Engineering*, 5, 78–83 (2014).

regional or national level. The associated assumptions can introduce significant (but undefined) uncertainty into the estimate.

Top-Down

The term top-down refers to measurements of methane emissions taken through atmospheric sampling that are used to infer total methane emissions in a region. The measurements may be from samples taken at ground-level or by an aircraft, satellite or remote platform. The analysis attempts to trace these measurements back to a source by inferring emission fluxes, modeling air currents, and/or using chemical markers that complement the methane measurement and are indicative of a certain source category. The greatest uncertainties associated with top down modeling are: 1) the ability to assign an amount of methane to a specific sector (e.g., oil & gas, landfill, or livestock) and within the sector; 2) differentiating between natural emissions, legacy emissions (e.g., leakage from abandoned (i.e., plugged) wells), and current usage emissions; and, 3) the accuracy of using measurements (and associated source operations) taken over a short duration as a basis for extrapolation to an annual estimate.