FAQ About the University of Texas Methane Study Phase I

Why is the University of Texas (UT) study important?

Methane, the primary component of natural gas, is a powerful greenhouse gas — at least 84 times more potent than carbon dioxide over a 20-year time frame. The largest single source of U.S. methane emissions is the vast network of infrastructure that supplies natural gas. These emissions, if not controlled, pose a significant risk to the climate. In the near term, the opportunity to maximize the lower carbon characteristics of natural gas compared to other fossil fuels rests on whether methane emissions are well understood and whether they can be sufficiently controlled.

This is important work and what seems like small changes in percentages can have a large impact. For example, EPA currently estimates methane escaping during development and delivery of natural gas to be 1.5 percent of total U.S. production, including associated gas from oil wells. Getting that number down to one percent — controlling just a third of the emissions — would have the same climate benefit over the next 20 years as retiring another 10 percent of U.S. coal generation. That's a big deal, and it's possible. A key takeaway of the UT study is that emission control technologies, such as so-called green completions (see below), are available and effective at reducing methane emissions.

How does the UT study advance what we know?

The UT study takes the first in a series of steps to gather the facts on methane emissions from the natural gas supply chain. It provides the most complete information in 20 years on methane emissions associated with unconventional natural gas extraction — specifically, some of the first ever direct measurements on shale gas wells that use hydraulic fracturing. Nine participating natural gas companies (Anadarko, BG Group, Chevron, Encana, Pioneer, Shell, Southwestern Energy, Talisman Energy and XTO Energy) provided access to their production equipment and facilities around the country, allowing UT to measure at the source of emissions.

Drilling practices have evolved rapidly in recent years, and a new set of EPA regulations governing air emissions from natural gas wells (known as New Source Performance Standards, or NSPS) is now coming into force. The intent of this study is to deepen our understanding of methane emissions associated with natural gas production employing the types of practices being used in the field today. Recently, there have been varying estimates on the rate of methane emissions from the natural gas system, with total emissions estimates for the supply chain (production, processing, distribution and delivery) ranging from 1% to 8%. These estimates have largely relied on data published in a 1996 EPA and Gas Research Institute methane report. While data on methane has improved over the last few years, UT's study presents the first scientifically reviewed dataset of methane emissions gathered directly at the source during some activities associated with hydraulically fractured wells.

What are the study's conclusions about methane emissions from natural gas production?

UT estimates the national methane leakage rate associated with the phase of natural gas extraction to be equivalent to 0.42% of total U.S. natural gas produced. This finding is in line with EPA's current emission inventory estimate for the production segment of the supply chain, though the study also found emissions from specific phases of production are likely to be higher or lower than EPA estimates. For example, emissions from well completions were lower than estimated in the EPA inventory, in large part because many of the wells studied used emission control technologies. Other sources UT studied turned out to be higher than EPA estimates. This included emissions from pneumatics, equipment used to control routine operations at the well site, and equipment leaks. These findings point to activities where more can be done to contain overall production emissions. The study also found regional variations in the emission rates from pneumatic pumps and controllers — for example, emissions per pump in the Gulf Coast region were an order of magnitude higher than the Midcontinent region. Further study in the second phase of this project will focus on pneumatics and liquids unloading, in order to better determine the emissions profile of these specific components of the natural gas production sector.

What does the UT study tell us about EPA's NSPS regulations?

EPA's national emission standards that apply to new and refractured natural gas wells will take full effect in January 2015 and require use of Reduced Emissions Completions (RECs) practices, commonly known as green completions (an emissions control method that routes excess gas to sales). Since October 2012, operators are required under an early phase of EPA's NSPS to either flare (burn off) or capture these emissions with RECs. The majority of wells observed by UT used one of these capture and control methods. Eighteen wells used RECs or flares to reduce emissions during "flowback", the end of the hydraulic fracturing process when frac fluids and sands are drawn back up the well to make way for gas production. In the case of RECs, an approach some in industry claimed was not a viable option, this finding indicates the technology is available, it is effective and it is being implemented by some companies in the field. EPA was right to require green completions, and the agency's standards are beginning to achieve the desired effect.

As more producers move to comply with the EPA's REC requirements that go into effect in 2015, the study suggests, the greater use of RECs will reduce the emissions profile of the natural gas sector. No national survey of how many operators currently use RECs is available, but the data suggest that once this practice is required, emissions from this phase of the production process will decline, reflecting the well completion results seen in this study. Overall, the story told by the well completions data is a positive one. It shows green completions are feasible and can effectively reduce emissions. The data provide a clear picture of what industry can achieve once this suite of technologies is universally deployed.

Do the UT results indicate no further regulation of the oil and gas industry is required?

No. Some emission sources in the UT study are shown to emit more methane than current EPA estimates and point to potential opportunities where EPA can strengthen NSPS and facilitate additional methane reductions. In the production sector this includes replacing higher emitting pneumatics with low-bleed devices (pressurized controllers used for routine functions at a well pad designed to emit the least methane); regularly inspecting for leaks at wellheads and other equipment used in production and quickly repairing those leaks; and using best available technologies and maintenance practices to minimize emissions from compressors and other equipment. For well completions, where regulations only apply to new hydraulically fractured wells, an opportunity also exists to close the regulatory gaps to ensure producers control all well emissions, including those from oil wells and hybrid oil and gas wells.

Why do UT's production emissions estimates appear lower than those in the Howarth, et. al study?

Disparate research methods and underlying assumptions, in addition to geological differences, limit the ability to broadly compare one scientific study to another. One contrast likely to be made, but difficult to do, is between the new UT study (Allen et al.) and the April 2011 Howarth, et al. paper regarding methane emissions associated with U.S. natural gas production. Whereas the Allen, et al. paper includes new empirical data of actual methane emissions, the Howarth et al. study relies on pre-existing emissions estimates. Howarth et al. also uses different assumptions when calculating some emission sources. For well completions, for example, Howarth et al. assumed neither green completions nor flares were used to control emissions.

While that may have been the case several years ago, it isn't the case now, as the evidence from the UT study suggests. Once EPA regulations are fully implemented, all new hydraulically fractured natural gas wells will be required to use green completion technologies. A similarity exists around equipment leaks and routine venting, in which, Howarth et al. assumes emissions are between 0.3% and 1.9% of production and the UT study supports the lower end of the range, suggesting the potential use of best available technology and practices at the well sites observed by UT.

How does UT's research method compare to the use of aircraft overflight measurements?

The two are different but complementary. On-the-ground data collection is essential to identifying the specific sources of emissions, but there is a limitation to bottom-up measurements in that it is difficult to canvas all potential sources of emissions at any particular site. This means some emissions can be missed. There are millions of potential methane emissions sources ranging from well pads to storage facilities to miles of pipelines across the country and it is not possible to measure every source using bottom-up techniques. Aircraft overflight readings are effective in measuring total methane fluxes in a given area, which promises the ability to capture methane emissions that an on-the-ground approach alone might miss, but this method also has its limitations. It is challenging to apportion overflight results between multiple sources (i.e. landfills, agriculture, oil and gas production, gathering systems, processing and pipelines).

Together, these two methods can complement each other and provide greater insight and certainty than either method alone. EDF is working with a variety of academics and scientists to further explore how these two methods, deployed in concert, can further our understanding of the magnitude and sources of methane emissions across the natural gas supply chain.

What do the results suggest about the climate benefit of natural gas?

Whether natural gas can provide a climate benefit relative to other fossil fuels over the short to medium term depends on how much methane is lost, as gas moves from the well to our homes and businesses. Uncontrolled venting and leaks across the natural gas supply chain can eliminate the potential climate benefits of substituting natural gas for coal or oil for some period of time. The UT study measured methane emissions for some key sources associated with the production of gas at the well pad, but not for the gathering, processing, storage, local delivery or transportation use of this fuel. Until emissions from the entire supply chain have been measured, no definitive conclusions can be drawn about the climate benefit of natural gas relative to other fossil fuels. We expect to be in a better position to answer this question when the entire scientific body of work that EDF and its partners have underway is finished — including studies that will go beyond the UT study to shed additional light on production sector emissions.

If forthcoming studies of other phases of the natural gas supply chain also bring results similar to EPA estimates, that would mean that the nation's methane leakage rate could amount to roughly 1.5% of total U.S. production, not including emissions from end uses including those in homes, businesses, and natural gas fueling stations and vehicles. According to a recent paper in the *Proceedings of the National Academy of Sciences*, a leak rate of 1.5% would mean that switching from coal to natural gas in the generation of electricity is immediately beneficial for the climate, but switching from diesel to natural gas fueled vehicles would produce climate damage for decades.

In the meantime, we know enough to say that methane emissions are an important issue worth the time and attention of government and industry. Methane emissions must be reduced wherever possible, as soon as possible. And while there are companies that are demonstrating practices can be improved, more needs to be done by all sectors of the industry to get this right. Given the dramatic impact methane emissions have on global warming in the near term, we can't afford to wait.

Does the UT study data impact EDF's target of minimizing methane emissions to 1% or less?

EDF's fundamental goal is reducing methane emissions system-wide to the lowest possible extent. In pursuit of this, our immediate objective is to reduce total methane emission to a rate of 1% or less of total U.S. natural gas production. This objective is based on a framework EDF and other scientists developed last year to begin to explain the climate impact of natural gas. One percent is a performance level, based on best available science that presents a critical threshold when fuel switching to natural gas from any other fossil fuels can be good for the climate across all points in time — a true win, not a mixed bag.

Does the UT study give a complete picture of methane emissions from the natural gas system? No. Natural gas production is an important part of the natural gas system, but it is only one piece. The UT study was not intended to provide a complete picture of methane emissions from the supply chain or to be the definitive answer on production segment emissions. Rather it is intended to advance what is known about methane emissions from production and inform pre-existing estimates in this sector with hard data.

UT's study marks the first of sixteen methane studies in which EDF is participating, a groundbreaking series involving more than 90 partner universities, scientists, research facilities, and natural gas industry companies that will quantify national methane leakage rates using diverse and scientifically rigorous methods. The effort is designed to better understand how much methane is released across the entire natural gas supply chain, as new technologies have unlocked a vast supply of U.S. natural gas. Together, these studies will provide a clearer national picture of methane emissions. The UT study is the first link in this chain. But science will continue to evolve, as it should, and this body of work needs to be furthered by others to ensure the U.S. and other countries get a handle on methane emissions.

How representative is the UT study data?

Nine natural gas companies, out of thousands of producers in the U.S., volunteered for this study. The UT study collected data that characterized the practices at particular sites operated by the participating companies, not industry at large. In 2011, the participants accounted for roughly 12% of all U.S. gas wells, 16% of gross gas production and almost half of all new well completions. In 2012, the 150 production sites UT visited include 478 wells, or about 0.1% of the national total of 446,745 gas wells. While this study reflects only a portion of what is happening in the field in 2012, in the absence of a statistically valid national survey, we are only able to use the data we collected as the basis to assess the national implications of the results. This is the way the 1990s EPA/GRI study presented its results, which served as the basis for much of EPA's current inventory. However, if the emissions profile of other producers or other regions differs significantly from the results of the UT study, then the national emission estimates in this study may change.

How do the study authors know that the nine companies are representative of all natural gas producers?

They don't. There are some 2,000 natural gas producers in the U.S., and incomplete data exist on how many of them are currently performing RECs, are using other activities designed to capture methane, or are employing leading operational practices.

How were the sites selected?

UT researchers identified production activities to be tested in various basins across the country. Participating companies gave access to their production operations based on the criteria given to them by UT, with particular attention to locations where well completions were scheduled to occur.

This study was conducted using standard scientific procedures for this kind of research and sites were selected as follows: For completions, the study team provided time windows when the measurement team would be available in certain regions and host companies identified completions that would begin as soon as possible after the study team arrived. Sites selected for unloading, workover and production site sampling were selected based on proximity to completion sampling. Typically, a list of candidate sites was provided by the host company. If the list was too long to be entirely sampled in the allotted time, the study team selected sites based on ability to sample as many as possible in the time available.

At the time field measurements took place, the market price for natural gas was low, which limited the number of new wells being completed. This suggests that operators had a fewer number of sites to make available; typically the study team would sample the only completion available during their field deployment in a region. However, participating companies have affirmed that all sites meeting study criteria were made available during the time UT conducted its field campaign.

Where were the measurements taken?

UT sampled 150 natural gas production sites with wells using hydraulic fracturing across the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian regions. Measurements were taken at well pads in gas producing basins around the country to ensure the results presented a good cross-section of what's happening in the U.S. Data is provided by regions, to show emissions at a regional and national scale.

Why not disclose emissions by company?

This study was not intended to provide a company-by-company inventory of total emissions. The purpose of this study was to improve our understanding of emissions from natural gas production in major natural gas producing regions around the country and to gather data that could be aggregated and analyzed on a regional or national scale. Even though emissions are not linked to the specific companies, all of the data collected are being released to the public, along with the study's methodology and results that were scientifically reviewed by independent experts prior to submission for publication and by reviewers selected by the *Proceedings of the National Academy of Sciences* as part of the process PNAS undertook to decide if the research warranted publication. These data provide benefit to the public, regulators, industry and the scientific community in that there is now, for the first time, publicly available data on directly measured emissions, in addition to formula-based estimates.

Were study participants involved in the preparation of the results?

No. The data was processed by the study team independent of the study participants. The study participants, however, were asked to review draft results, reports and communications materials and provided UT with comments. A Scientific Advisory Panel made up of six independent academic experts also reviewed the project plans before data collection began and preliminary findings during data collection. The Panel also reviewed the draft final report and co-authored the published manuscript. However, UT retained total control, and had ultimate authority, over the content of the PNAS paper, how the results would be reported, how to release the full dataset and communicate publically about the results.

When there was disagreement on how data should best be interpreted, it was noted in the study. For example, through discussions about the nine liquids unloading measurements it was determined that the data were insufficient to scale nationally, as described in the report. Open questions surrounding liquids unloading are largely why some participants agreed to a second phase of the UT study in order to transparently gather additional data to address areas of uncertainty.

Why was Dr. David Allen selected to lead this study?

Dr. Allen is a highly respected scientist in the field of air quality. Previously he was a lead investigator for one of the largest and most successful air quality studies: the Texas Air Quality Study. He was a long time member of the EPA's Science Advisory Board (SAB), on which he has served on since 2002 and has focused on issues of air quality modeling and cost-benefit analysis of the Clean Air Act. Since the start of the UT study, Dr. Allen has taken over the role of chair of the EPA's SAB.

How can we trust science funded in part by industry? How was rigor and scientific integrity assured?

One of the key elements of this study, and the rest of those supported by EDF, is an ability to verify its scientific integrity at every step of the process. Built into the research process of each industry sponsored study is an independent Scientific Advisory Panel. Scientific experts from academic and other institutions served as external advisors and reviewed the procedures, results and conclusions. These reviewers received standard government rate remuneration for their time. The study results and dataset then went through additional peer review as part of the evaluation by the external reviewers selected by the journal editor. The integrity of the UT study is reflected by acceptance for publication in the *Proceedings of National Academy of Sciences*, one of the nation's most prestigious scientific journals. Another critical aspect is that the data is being made public, allowing others to analyze it independently and critically examine the reported results.

Is this data more reliable than previous methane studies?

This study focused on making measurements of methane at the point of emissions. Recent attempts to estimate methane emissions from natural gas have been based on emission factors, which are estimates of the emissions coming from various types of equipment and processes rather than direct measurement. Data collected for the UT study were gathered at the site of production using multiple scientifically rigorous methods — independent measurements of methane emissions were made using different approaches and the results then compared. This inter-comparison using both bottom-up and top-down techniques provided strong evidence of the robustness of the data quality.

Will the participant companies take action on the higher emission source categories?

Only the individual companies can answer this question. But, based on some of the UT study findings, as well as what can be learned from other recent studies such as the one reporting high regional methane emissions in the Uintah Basin in Utah, there is more that can and should be done industry-wide to control emissions.

Why is EDF working with industry on these studies?

We know some don't like the idea of environmentalists working with industry to solve problems, but industry involvement and access to facilities is critical to advancing our understanding of the magnitude and source of emissions. This is because estimates of methane emissions from the natural gas supply chain have varied widely as a result of reports relying heavily on emissions factors derived from nearly 20 year-old data. Radical changes in technology, such as the rapid rise of hydraulic fracturing combined with horizontal drilling, and industry practices have occurred since then — leaving a knowledge gap in what we know about from where and how much methane is lost today across the supply chain.

Industry also knows the natural gas system well, and their input in designing the protocols and scope of these studies have been invaluable to the researchers' ability to gather data accurately, effectively and safely.

EDF never accepts funding from energy companies or their corporate foundations. We never have and never will. What we require in exchange for our involvement in this collaborative research effort is the companies' steadfast commitment to terms that we can be collectively proud of: making all the results and data publicly available, peer-review throughout the study, release of the results through peer-reviewed publications, and control of the research by independent academic scientists.

Were there any production activities that the UT study did not measure?

Yes. No high-bleed pneumatics were observed at production sites UT sampled. These represent an additional source of production emissions; recent EPA data and a 2012 American Petroleum Institute and American Natural Gas Alliance report high-bleed pneumatics to account for 10% and 24%, respectively, of the total number of pneumatic devices used in the field. While the study also includes some measurements of emissions from storage tanks at active production sites, these measurements did not capture all emissions and as a result, were not analyzed by UT.

Moreover, the study measured significant sources reported by EPA to represent roughly 55% of methane emissions in the production sector. However, the remaining portion, including sources such as dehydrator vents and engine exhaust were not measured. They were not prioritized since there are dozens of individual and relatively small sources comprising this 30% and because it is unclear if there are cost-effective avenues to reduce methane emissions.

Are there public health or local air quality implications of the emissions data that was collected?

The UT study did not include a health impacts assessment; the emissions measurements were not evaluated for purposes of assessing health and safety. The study quantified methane emissions rates from discrete sources at well sites. This study also did not assess the impacts of methane or other emissions on air quality. Methane is relatively slow to react in the atmosphere so its effects on air quality would occur on a large regional or global scale. Some papers have reported health benefits of global methane reductions due to resultant reductions in tropospheric ozone levels. The study did not quantify emissions of other constituents of natural gas, including hydrocarbons such as benzene and volatile organic compounds, which can contribute to more localized air pollution. These, and other related air pollution issues associated with oil and gas production, deserve further study.

Why did the wells with no capture or control technology still have low emissions?

The nine wells surveyed that had no control technology were expected to have low initial gas production compared to the controlled wells. In other words, the wells with uncontrolled releases had much lower than average potential to emit. Uncontrolled well completions with higher potential to emit would be expected to have higher emissions.

Does this study show that EPA’s estimates of completion emissions are flawed?

No. EPA’s estimates predate the requirement that facilities perform green completions. Federal requirements didn’t exist in 2011, the year of EPA’s most recent estimates (released in 2013). The EPA’s 2011 estimates only included emission reductions from green recompletions required by Colorado and Wyoming state regulations or voluntarily reported to EPA. EPA will revise future estimates to reflect green completions required by the NSPS.

That doesn’t mean the work ends there. As industry evolves, so does the science and the need for policy reform. The study findings point to potential areas where additional mitigation strategies for equipment leaks or pneumatics could help reduce emissions.

What are the most important gaps in current regulation?

Considerable opportunities exist under the Clean Air Act to strengthen NSPS in order to further reduce methane emissions. Currently NSPS does not require emissions controls for equipment routinely found at oil and natural gas production sites, such as valves or connectors at the well pad or pressure relief valves on storage tanks. Nor are there federal requirements for the nearly half a million existing pneumatic devices at natural gas wells, controlling various mechanical operations, and for the thousands of existing compressors, pressurized motors used to move the gas from the wellhead through processing plants and pipelines before reaching end users.

Similarly the NSPS do not contain requirements to reduce completion and production-related emissions from wells that produce both oil and natural gas (known as “co-producing wells.”), which are becoming much more common as the price of oil remains high. Finally, robust leak detection and repair requirements are necessary to assure the equipment in the field is operated and maintained properly at all times. Many of the same cost-effective clean air measures that the NSPS deploys can be used to reduce emissions from these potentially significant sources. An additional opportunity for emissions reductions should be considered as further data unfolds around liquids unloading.

Which companies are involved in phase two and what does this project entail?

Anadarko, BG Group, Chevron, Conoco-Phillips, Encana, Pioneer, Shell, Southwestern Energy, Statoil and XTO Energy are all participating in the UT study phase two, already underway. The project is focused on collecting more data on methane emissions from liquids unloading and conducting further study of pneumatics devices in order to better explain regional variations in emissions rates observed by UT’s initial work. This effort is expected to result in a paper submitted for scientific peer review in March 2014.

Why study pneumatics and liquids unloading further but not well completions?

Pneumatic controllers were the largest emission source observed in the first phase of UT’s work and a better understanding of their emissions, particularly the regional variations, could lead to more effective mitigation options. Additionally, no high-bleed pneumatics were measured and more data is needed to accurately characterize emissions from pneumatics in the field. For liquids unloading, only nine measurements were made with large variability observed. EPA’s estimates of liquids unloading have changed considerably over the last few years, pointing to the need for additional data to answer important questions about this potential emissions source. It is likely EPA and the UT study datasets for well completions will converge as EPA’s NSPS requires broad adoption of green completions in January 2015.

Why is there so much disparity in published U.S. methane leakage rates?

Accurately calculating a methane leakage rate to explain total methane emissions is difficult because regional and site specific differences can be large. Things like the basin’s geology (porosity and permeability of the rock), whether oil or gas dominates production and if the basin produces wet or dry gas, which is primarily made up of methane, whereas wet gas also includes ethane, butane, propane and pentane. Equipment and field performance, state regulation and other factors can play a role in the amount of methane leakage observed. Part of the confusion also stems from a lack of any standard set of metrics for what is being observed. For example, an oil basin with very little gas production could skew results if a methane leak rate was calculated, as typically done, by dividing the total methane emissions by the amount of gas produced. Such an approach could yield leakage rates in excess of 100% - a non-sensible scientific conclusion!

What can the data tell us about regional emissions?

The UT study observed regional differences for certain sources. For example, emissions from pneumatic controllers were lower in the Rockies than in the Appalachian, Gulf Coast or Mid-continent regions. Similarly, emissions from pneumatic pumps in the Gulf Coast were statistically higher than those in the Midcontinent. Regional differences were not as pronounced for equipment leaks. It is hard to characterize the causes of these differences without further study and a better understanding of regional variations in equipment and activities, particularly those observed among liquids unloadings and pneumatics. Additional data is being collected as part of the second phase of the UT study to help answer these questions.

Does the UT study show methane is an urgent issue?

Absolutely yes. While this study shows lower than previously indicated emissions rates for certain production activities operated by some leading companies, there are other areas that were reported to be higher than EPA’s current estimates. Without further improvements across the entire supply chain, natural gas will not be in a position to help the U.S. meet its climate goals.

Methane requires attention now.

For the natural gas industry, it’s an issue to own in order to show it is serious about delivering on its environmental promises. Industry has unparalleled technological skill and can tackle big challenges — IF it’s a priority. Better control of methane emissions improves operations, and in many cases delivers a financial payback.

For the climate, it’s a make or break moment. This is because methane is much more potent than carbon dioxide — ounce for ounce methane is at least 84 times more powerful than CO_2 over the first two decades after it is released. In other words, increasing methane emissions means higher temperatures, longer droughts and more extreme weather over the near to medium term.

Now it is critical for policymakers and industry to put the data collected to work. The additional data released over the next year will inform this important work, but we know enough to get started. There is no reason to wait.