2017

DISCLOSING THE FACTS:

TRANSPARENCY AND RISK IN METHANE EMISSIONS

A COLLABORATIVE PROJECT OF:

AS YOU SOW®

BOSTON COMMON ASSET MANAGEMENT

Investor Environmental Health Network
HEALTHY PEOPLE...HEALTHY BUSINESS

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AS YOU SOW promotes environmental and social corporate responsibility through shareholder advocacy, coalition building, and innovative legal strategies. Our efforts create large-scale systemic change by establishing sustainable and equitable corporate practices.

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THE INVESTOR ENVIRONMENTAL HEALTH NETWORK (IEHN) is a collaborative partnership of investment managers and advisors concerned about the impact of corporate practices on environmental health.

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DISCLAIMER

COVER CREDIT: Earthworks — Optical gas imaging camera makes compressor emissions visible, Ohio

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EXECUTIVE SUMMARY

Disclosing the Facts 2017: Transparency and Risk in Methane Emissions (DTF 2017) is an investor report designed to promote improved methane management and reporting practices among oil and gas producers. This report is both broader and more limited than prior Disclosing the Facts reports. Prior DTF reports have focused on best practices across a range of risk areas (chemicals, air, water, community impacts) by oil and gas companies engaged in horizontal drilling and hydraulic fracturing in the United States and Canada. While *DTF 2017* focuses on a single issue—methane emissions management—the report does not limit its focus to fracturing operations in unconventional resources. Since methane emissions can occur across unconventional and conventional upstream exploration and development, this full range of operations is included.

We note the entire natural gas value chain merits attention, from upstream production operations through distribution to end-users (power plants, manufacturing operations, and business and residential consumers). The U.S. Environmental Protection Agency estimates that natural gas and petroleum systems are the largest contributors to U.S. methane emissions, with upstream gas and oil production contributing 72 percent of the system's methane emissions.

Investors are focused on methane because it is the primary component of natural gas and has an intense, short-term climate forcing impact. Over a twenty-year period, methane's "global warming potential" is at least 84 times that of carbon dioxide. Natural gas is often promoted as a bridge fuel to help move the global economy away from high carbon energy sources such as coal. Accordingly, oil and gas companies are increasing the percentage of gas in their energy resource base, with the intent of decreasing the greenhouse gas intensity of their product mix. But while natural gas *burns* more cleanly than coal, to the extent methane emissions from across the natural gas and oil value chain are not controlled, the potential benefit from burning gas over coal will be lowered.

Investors' attention to methane reflects their increasing focus on reducing "carbon risk" in their portfolios. Portfolios commonly hold a wide spectrum of economic sectors, so issues from rising sea levels, to increased storms, physical damage to buildings and infrastructure, changes in water availability, and reduced agricultural productivity, among others, caused by a warming globe will have negative long-term portfolio implications. In fact, these harms are already being felt across the U.S. as 2017 brought some of the most intense hurricanes on record, floods, drought, and raging wild fires across western states. Global regulatory responses to climate change are also increasing business risk to carbon-intensive companies such as oil and gas producers. Governments around the globe have agreed to take measures to keep warming well below 2 degrees Celsius, highlighting the global intention to transition away from carbon-intensive fuels.

Reducing methane emissions can also be cost-effective for companies. Efficiencies can be improved as new methane-reducing equipment is put on-line and methane emissions can be captured and placed in pipelines for sale or used to power operations. The rate of return on investment depends on amounts of gas captured, efficiencies achieved, the expense of monitoring and capture, and the market price of natural gas.

Following the maxim of "what gets measured gets managed," and to address rising investor concern, *DTF 2017* ranks companies on disclosures of key elements of their methane emission management and reduction processes. *DTF 2017* seeks disclosure not only of quantitative information about the impacts of company operations to eliminate methane emissions but also qualitative information about corporate policies and practices. Sound corporate management of upstream methane emissions requires thorough, systematic planning, from site development through capturing gas and oil in pipelines. New wells need to be sited near existing gas transport infrastructure or not placed in operation until such infrastructure is created. Companies should deploy advanced equipment designs that eliminate or minimize emissions. Focused emissions monitoring and measuring programs will not only end existing leaks, but help establish maintenance priorities for preventing emissions.

Methane emissions management programs should encompass the thousands of existing facilities whose construction predates U.S. EPA regulations that impose tighter standards on new and modified facilities. Because of their age and use of older technologies, existing facilities may be especially sizeable emitters. The best company programs establish targets for reducing overall emissions intensity (the percentage of methane emissions compared to production), provide economic incentives to senior and field staff for reductions, and report progress over time. Since the U.S. EPA emissions inventory is based primarily on increasingly outdated engineering calculations and measurements, improved emission measurements are essential. The best company programs will generate measurement data to focus company reduction initiatives and help improve the EPA inventory data.

Disclosing the Facts 2017 comes at a time of increased industry attention to methane emissions and regulatory change. This increased focus on methane is highlighted in a number of recent announcements of voluntary emissions reductions, reporting measures, and reduction targets. The American Petroleum Institute announced the formation of an environmental partnership of 26 companies, including many of the top U.S. natural gas producers, to cut methane leaks from wells and other U.S. onshore production sources. Reporting under this system will be a compilation of members' actions, with no clear commitment to company-specific disclosure. In November, large international oil and gas companies including ExxonMobil, signed on to "guiding principles" for cutting methane emissions. These announcements are in addition to voluntary commitments and reduction targets announced in 2014 and 2016 by members of the ONE Future Coalition.

It is noteworthy that these industry announcements come in the face of persistent federal efforts to roll back existing methane regulations in the U.S. As this plays out, investors will continue to advocate for sustained action and objective, quantitative disclosures by industry, regardless of regulatory status. A clear goal of this report is to establish a set of well-defined, minimum guidelines for methane management and disclosure by oil and gas companies.

Disclosing the Facts 2017 poses 13 questions reflecting a thorough, systematic approach to methane emissions management. The actions of 28 companies are assessed against these criteria, which range from engineering and maintenance practices, to thoroughness of Leak Detection and Repair (LDAR) programs, leak repair times, beyond-compliance venting and flaring reduction programs, replacement of high-bleed pneumatic controllers at existing facilities, and progress in and incentives for achieving methane intensity targets. To speed adoption within the industry of enhanced emission detection and reduction, *Disclosing the Facts 2017* highlights nearly 50 notable practices by individual companies whose adoption other companies should consider.

2017 SCORECARD

COMPANY	TOTAL
Apache	12
BHP	12
Southwestern	12
Conoco	11
Hess	11
Shell	11
Chesapeake	10
Newfield	10
Range	10
Exxon	9
Noble	9
Pioneer	9
Carrizo	7
CONSOL	7
Devon	7
EOG	6
Anadarko	5
WPX	5
Antero	4
Occidental	4
BP	3
Chevron	2
Continental	1
EQT	1
QEP	1
Cabot	0
Whiting	1
Encana	0

FINDINGS

1. Apache, BHP, and Southwestern Energy were the three top-scoring companies, earning 12 of 13 possible points. ConocoPhillips, Hess, and Shell were close behind at 11 points each, followed by Chesapeake Energy, Newfield Exploration, and Range Resources at 10 each, and Exxon Mobil, Noble Energy, and Pioneer Natural Resources at 9 each.

2. Conversely, eight companies scored just 0-3 points. Encana and Cabot Oil & Gas received no credit; Continental, EQT Resources, QEP Resources, and Whiting Petroleum earned 1 point each; Chevron earned 2; and BP earned 3 points. We believe such low results should lead to a strong investor call to action for these companies. As demonstrated by the large number of leading scorers, and the broader industry movement toward action that we are seeing, methane reduction is both feasible and strikingly important in decarbonizing energy markets. If natural gas is not significantly less carbon intensive than coal because of methane emissions, a major selling point has been lost.

3. We note that the leaders in scoring this year include companies that have had a long-term commitment to sustainability reporting, companies that more recently have come to understand the value of such reporting, and companies spurred to improve disclosures through an ongoing dialogue and/or shareholder proposal process with investors.

4. Companies earned credit most frequently for reporting the type of leak detection methods in use by the company, such as on-site observations by field staff or use of infrared camera technology. Companies were less likely to specify how often and where within facilities they used such methods, especially with regard to use of monitoring equipment.

5. The lowest scoring or least answered question addressed whether companies had adopted a quantitative methane emissions reduction target. Only four companies in DTF 2017 have established methane reduction targets. All of these companies are participating in the ONE Future Coalition. (Apache, BHP, Hess, and Southwestern Energy).

6. A second low-scoring question asked if companies incentivize greenhouse gas reductions at the Board, management, or staff levels. Investors have increasingly demonstrated their concern about carbon risk, both to the companies they hold in their portfolios and from the broader portfolio perspective. Incentivizing greenhouse gas reduction action is a clear means of moving companies to focus on carbon reduction, thereby reducing carbon risk.

7. The report emphasizes that strengthened leak detection and repair programs are essential to improving methane management. A number of recent studies have uncovered the phenomenon of "super-emitters" —large leaks from random equipment failures. Researchers have not found predictable patterns of super-emitters towards which preventive actions should be targeted, making leak detection important to finding and repairing these large sources of leaking methane.

    a. Companies with LDAR programs that address a broad range of potential sources and that monitor more, rather than less, frequently (for example quarterly rather than annually) are more likely to detect super-emitters than those companies that do not, enhancing their chances of capturing emissions that would be lost to the atmosphere.

    b. Through increased leak detection required by regulations or done voluntarily, some companies are generating expanded internal emission inventories. These include more emission points than regulations require to be reported and they generate data to better focus companies' equipment redesign and preventive maintenance actions.

8. Most data compiled on methane emissions are based on engineering estimates and assumptions; actual emission measurements are relatively rare. Research collaborations of The Environmental Defense Fund, companies, and universities have begun generating useful data that underscore the shortfalls of current EPA emission factors, the most commonly used estimates.

9. Nearly 60 percent of the companies analyzed have no high-bleed pneumatic controllers or they have established goals for eliminating their remaining ones. Pneumatic controllers are estimated to produce 30 percent of the methane emissions from oil and gas production. Companies are substituting low-bleed controllers that release less methane and controllers using compressed air rather than methane, some of which are powered by solar energy.

10. Companies relying on technical innovations to lower emissions report using improved thief hatch designs, automated systems that eliminate the need to open thief hatches on storage tanks, and equipment designs to lower emission risks from facilities subject to especially corrosive oil and gas production.

11. Currently available leak detection technologies can cost tens of thousands of dollars each. But industry's increased focus on methane emission management is driving improved technologies and reduced costs. We believe that technological innovation will continue unabated with resulting lower detection and measurement costs, increased accuracy of monitoring equipment, and an increased variety of ways in which data can be captured—including for instance use of drones and airplane-based equipment. Some companies have joined with partners to spur development of such technologies, with many new technologies in the early stages of pilot testing. These include continuous emission monitors that would constantly track emissions.

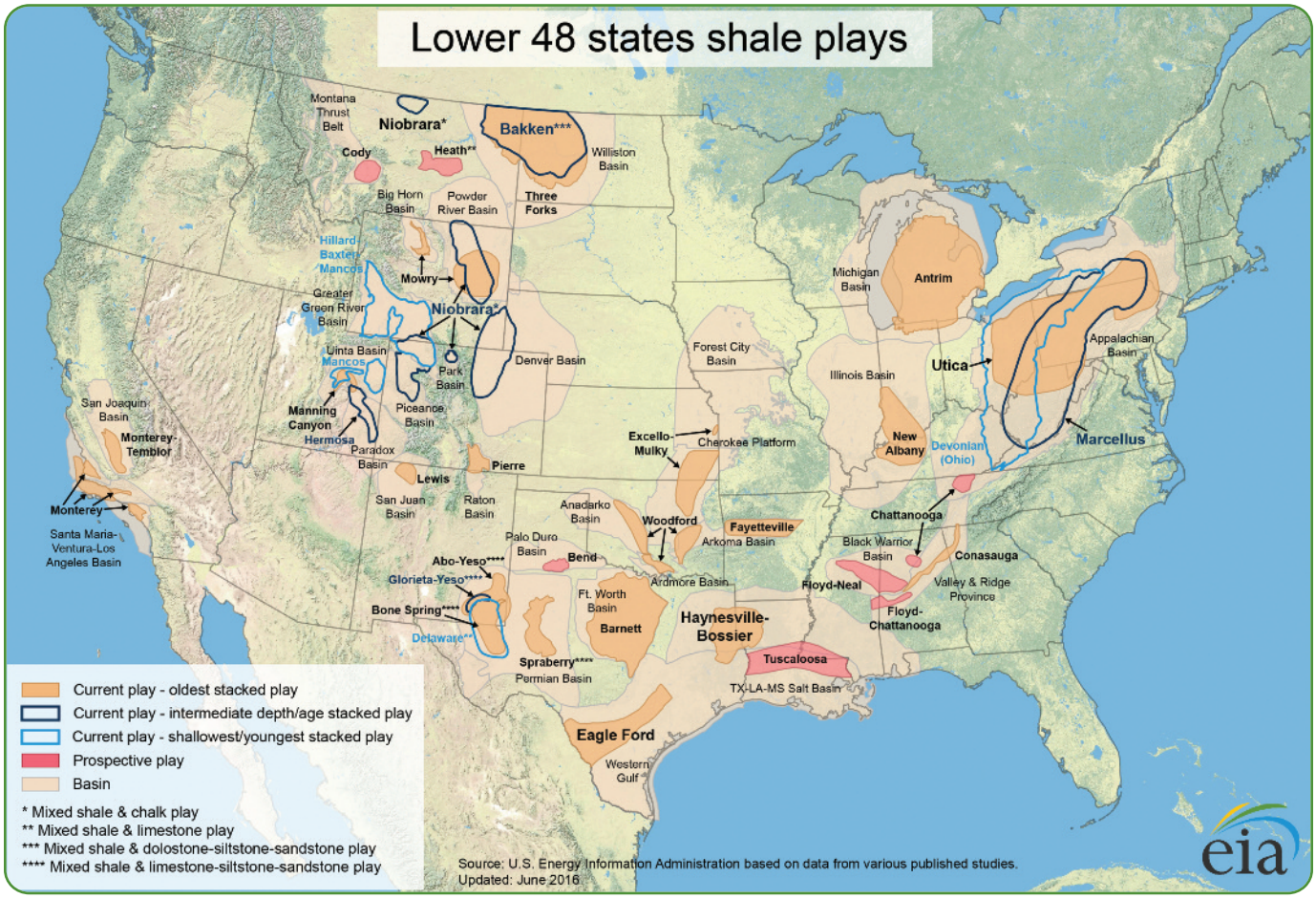


IMAGE: U.S. Energy Information Administration

Source: U.S. Energy Information Administration based on data from various published studies.
Updated: June 2016

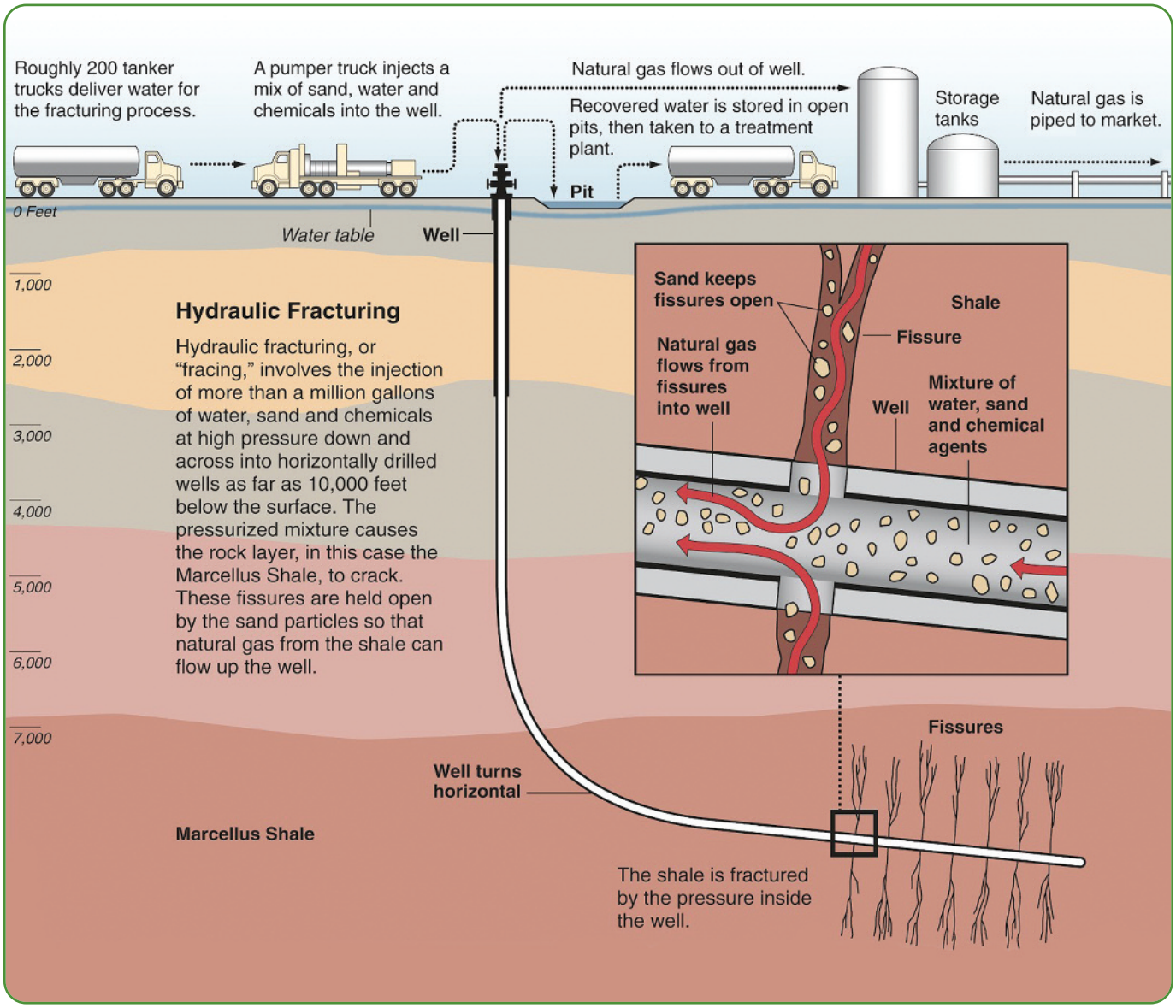


IMAGE: Al Granberg / Propublica.org

INTRODUCTION

Disclosing the Facts 2017 (hereafter *DTF 2017*) is the fifth in a series of annual scorecards assessing how well upstream oil and gas companies in the United States and Canada manage and disclose the risks from their oil and gas operations, including risks from hydraulic fracturing. Public pension funds, banks, and faith-based and socially responsible investors, have been pressing companies—through dialogue meetings and, when necessary, shareholder proposals—to be more transparent about how they manage and mitigate the risks inherent in their operations.

Investors require rigorous, relevant information to make informed investment decisions; hence, this report emphasizes quantitative reporting. One risk, in particular, has drawn heightened public and investor interest in recent years: the level of methane emissions associated with oil and gas production. *DTF 2017* focuses exclusively on methane risk management because of the considerable risk of global warming and catastrophic climate change to investor portfolios around the world and to the companies in their portfolios.[1] According to the International Energy Agency's World Energy Outlook 2017, "Stepping up action to tackle methane leaks along the oil and gas value chain is essential to bolster the environmental case for gas: these emissions are not the only anthropogenic emissions of methane, but they are likely to be among the cheapest to abate."[2]

CARBON RISK: Investors' concern about methane reflects their increasing focus on reducing "carbon risk" in their portfolios.[3] Climate change is a global problem that is increasingly harming people, the environment, and the global economy. In late 2017, the fourth National Climate Assessment, produced by a collaboration of U.S. government scientific agencies, concluded that it is extremely likely that human actions are the primary cause of global warming. The report underscored the growing impacts of climate change including that "heavy rainfall is increasing in intensity and frequency across the United States and globally and is expected to continue to increase"; heatwaves in the U.S. have become more frequent and extreme cold temperatures and cold waves less frequent since the 1960s; incidence of large forest fires in the western U.S. and Alaska has increased since the early 1980s; and trends toward earlier spring melt and reduced snowpack are affecting water resources in the western U.S. Such trends are expected to increase. The report described the potential for "compound extreme events" and found that current "[c]limate models are more likely to underestimate than to overestimate the amount of long-term future change." The report concluded that the only solution to the problem is to reduce the amount of greenhouse gases emitted globally.[4]

Since most investors hold corporate stock and securities across a wide spectrum of economic sectors, changes associated with a warming climate, including rising sea levels, increased and stronger storms, physical impacts to plants and infrastructure, and changes in water availability and agricultural productivity, among others, have broad long-term portfolio implications. Global regulatory responses to climate change are also increasing corporate carbon risk. Public policy makers around the globe have agreed to take measures to keep warming well below 2 degrees Celsius,[5] highlighting the global intention to transition away from carbon-intense energy sources.[6]

1. We expect that *DTF 2018* will address the wider range of hydraulic fracturing operation risks, including toxic chemicals, water sourcing and wastewater management, community impacts, and management accountability.

2. https://www.iea.org/weo2017/.

3. See Task Force on Climate-Related Disclosures, "Final Report: recommendations of the task force on climate-related financial disclosures", 2017, https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-TCFD-Report-062817.pdf;
Moody's, "Announcement: Moody's: Significant credit risks arise for oil and gas industry from carbon transition", 2017, https://www.moodys.com/research/Moodys-Significant-credit-risks-arise-for-oil-and-gas-industry--PR_365728;
Wood MacKenzie, "The impact of rapid growth in renewables", 2016, https://www.woodmac.com/media-centre/12533989.

4. U.S. Global Change Research Program, *Climate Science Special Report: Fourth National Climate Assessment, Volume I*, p. 14, 2017, https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf. See pp. 10-11 for additional material cited in text.

5. "Why 2 degrees Celsius is climate change's magic number", *PBS Newshour*, 2015, http://www.pbs.org/newshour/bb/why-2-degrees-celsius-is-climate-changes-magic-number/.

6 The terms "carbon-intense" and "high-carbon" as used throughout this report include all greenhouse gas emissions, including methane.

The mainstreaming of climate change concerns among major institutional investors is reflected in the high votes on climate-related shareholder proposals at oil and gas company annual meetings in 2017. Many resolutions asked that companies report to shareowners the growing risks to their operations of an increasingly low-carbon economy, including how their operations will fare under the 2-degree global warming target of the Paris climate change accord.[7] A 2-degree carbon risk resolution at ExxonMobil received an unprecedented 62.1 percent vote and a similar proposal at Occidental Petroleum received a 67.3 percent vote.[8] These votes represent the first time environmentally related resolutions have received majority votes in the face of opposition from company management. Further, they demonstrate a growing recognition that resource constraints and environmental harms can have significant economic impacts. Shareholder proposals addressing methane emissions also received strong votes this past year.[9]

Many investors are also embracing sustainability investing, which recognizes the impact of environmental, social, and governance (ESG) factors on corporate financial performance. For example, BlackRock, the world's largest investment management firm, with $5.7 trillion in assets under management, has stated that ESG "is not just about saving the planet or feeling good. We view ESG excellence as a mark of operational and management quality".[10] BlackRock CEO Larry Fink specifically underscored climate change as an ESG issue that, over the long term, will "have real and quantifiable financial impacts".[11] Accordingly, BlackRock issued a report on how investors can take climate change into account in their portfolios.[12]

METHANE: Methane is the primary component of natural gas.[13] Over a 20-year period, methane has a "global warming potential" of at least 84 times that of carbon dioxide.[14] Avoiding methane emissions in the near term can help facilitate achievement of the 2-degree global climate goal. Further, although natural gas burns more cleanly than coal, to the extent methane leaks and emissions across the natural gas supply chain are not controlled, natural gas' greenhouse gas benefits (compared to coal) may not be realized, reducing the benefit of switching to natural gas. Fortunately, methane reduction in the oil and gas sector is achievable with current technology, presenting an opportunity to achieve significant emissions reductions.

Following the maxim of "what gets measured, gets managed", *DTF 2017* ranks companies on disclosures of key elements of their methane emissions management and reduction processes. Quantitative reporting on methane emissions provides assurance to investors that companies have appropriate oversight and accountability practices in place to track—and therefore to mitigate—impacts of their operations. Companies implementing best practices in

7. The Trump Administration has been backing away from the Paris accord and federal methane regulation. But, as noted in the text below, other nations remain committed and numerous U.S. companies, states, and cities remain committed to reducing reliance on high-carbon energy resources.

8. See https://tools.ceres.org/resources/tools/resolutions/exxon-2-degrees-scenario-analysis-2017/ and https://tools.ceres.org/resources/tools/resolutions/occidental-petroleum-2-degree-scenario-analysis-2017.

9. See methane resolutions listed at Ceres, "Shareholder Resolutions", https://tools.ceres.org/resources/tools/resolutions/@@resolutions_s3_view#!/subject=Methane%20Emissions&year=&company=&filer=&sector=&status=&memo=&all.

10. BlackRock, "The price of climate change: Global warming's impact on portfolios", 2015, p. 2, https://www.blackrock.com/investing/literature/whitepaper/bii-pricing-climate-risk-us.pdf. BlackRock AUM figure is as of June 30, 2017.

11. Business Insider, "Here is the letter the world's largest investor, BlackRock CEO Larry Fink, just sent to CEOs everywhere", 2016, http://www.businessinsider.com/blackrock-ceo-larry-fink-letter-to-sp-500-ceos-2016-2.

12. BlackRock, "Adapting portfolios to climate change: Implications and strategies for all investors," Sept. 2016, https://www.blackrock.com/investing/literature/whitepaper/bii-climate-change-2016-us.pdf.

13. Natural gas contains mostly methane but also includes varying amounts of other hydrocarbons, such as ethane, propane, and butane pollutants; volatile organic compounds (VOCs), which are a key ingredient in ground-level ozone (smog); and a number of pollutants known as "air toxics"—in particular, benzene, toluene, ethylbenzene and xylene. https://www.epa.gov/sites/production/files/2016-09/documents/epa-oilandgasactions-may2016_presentation.pdf. To provide a common metric for reporting the impact on climate change of these diverse gases and of carbon dioxide emissions, companies often report emissions of methane and these other gases in terms of "carbon dioxide equivalents"

14. Intergovernmental Panel on Climate Change, "Climate Change 2013: The Physical Science Basis", p. 714, http://www.climatechange2013.org/report/.

operations and providing transparent information about these efforts will reduce regulatory and reputational risk, enhance the likelihood of securing and maintaining their social license to operate, and reduce legal liabilities. Reducing methane emissions not only reduces risk, but also can be cost-effective for companies. Methane that otherwise would escape to the atmosphere can be captured and sold. The rate of return on investment depends on amounts captured, the expense of monitoring and capture, and the market price of natural gas.

DTF 2017 encourages oil and gas companies to increase disclosure about their use of current best practices in measuring and minimizing methane emissions. Some of the *DTF 2017* questions have been asked in prior editions of *Disclosing the Facts* and in other investor reports on methane while other questions are posed for the first time, reflecting learnings from prior reports and signaling the direction in which more robust disclosure by companies should move.

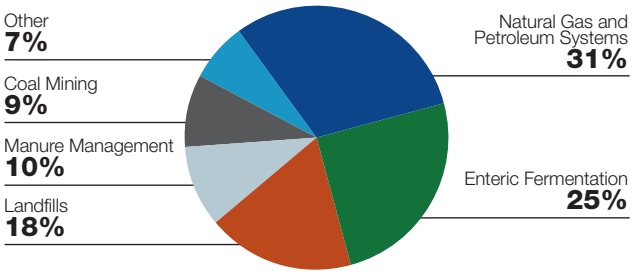
This report contains considerable technical information because many investors are reviewing company actions at this level. Definitions of technical terms are integrated in the text and compiled in Appendix C. The discussion provided in this report will help enable investors to ask more probing questions in their engagements with corporations, to more robustly assess the quality of company methane emission reduction programs, and to be able to better understand risk and opportunity as it applies to particular companies.

ESTIMATED METHANE EMISSIONS IN THE UNITED STATES

In the United States, natural gas and petroleum systems contribute 31 percent of methane emissions, as shown in Figure 1.[15]

Figure 2 displays several components of the natural gas value chain—oil and gas production,[16] processing, transmission, storage, and distribution. Oil and gas production is responsible for 72 percent of the emissions from this value chain.[17]

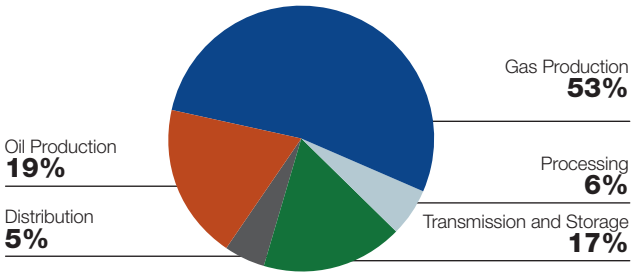
FIGURE 1
2015 U.S. METHANE EMISSIONS BY SOURCE



Note: All emission estimates from the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015.

Source: https://www.epa.gov/ghgemissions/overview-greenhouse-gases#methane

FIGURE 2
2015 OIL AND GAS METHANE EMISSIONS BY SEGMENT (~201 MMTCO2e)



Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015, USEPA, April 2017

Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry

15. https://www.epa.gov/ghgemissions/overview-greenhouse-gases#methane. As shown in Figure 1, the second largest source of methane emissions is cattle.

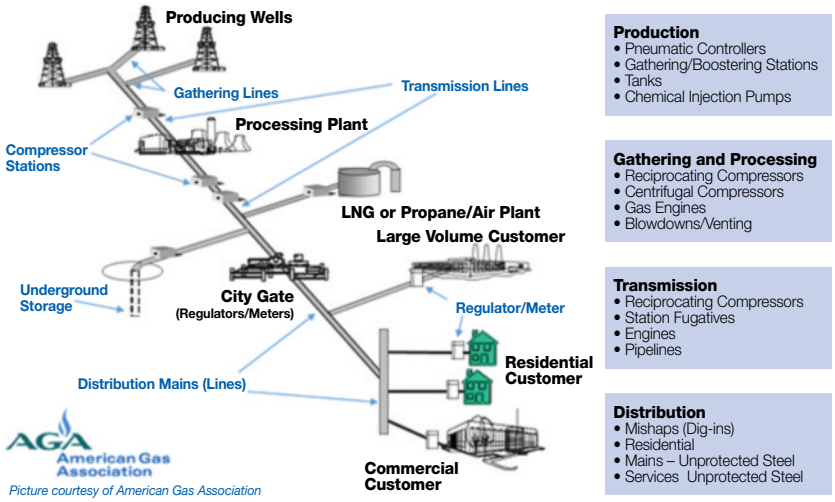
16. When oil is the major target of drilling and production, associated natural gas may, depending on its volume, be flared (burned at the pad-site) or separated into a pipeline for sale.

17. The U.S. Environmental Protection Agency, "Overview of the Oil and Natural Gas Industry", https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry.

Figure 3 describes the major sources of methane emissions in each sector of the oil and gas industry—production, gathering and processing, transmission, and distribution. The U.S. Environmental Protection Agency (US EPA) describes methane emissions along this system as stemming from: 1) normal operations, 2) routine maintenance, 3) fugitive emissions (leaks), and 4) system "upsets".[18] Emissions occur through both intentional venting (direct releases to the atmosphere) and unintentional leaks. Venting can occur through equipment design, operational practices, or venting from well completions during production. Leaks can occur throughout the oil and gas value chain infrastructure, including, for example, from connections, valves, equipment, poorly constructed producing wells, and poorly plugged non-producing wells.

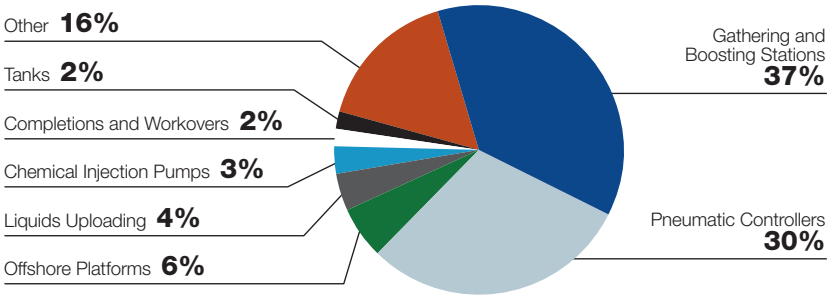
Figure 4, using slightly different categories, quantifies the major sources of methane emissions within various parts of oil and gas production. Pneumatic controllers, at 30 percent, comprise the second largest source of methane emissions.[19]

FIGURE 3
The diagram below displays the segments of the oil and natural gas industry and presents the top methane emission sources for each sector.



Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry#sources

FIGURE 4
2015 OIL AND GAS PRODUCTION (~145 MMTCO2e)



Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015, USEPA, April 2017
Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry

METHANE IN OIL AND GAS OPERATIONS

VENTING, FLARING, AND FUGITIVE EMISSION SOURCES

Venting—the direct release of methane to the atmosphere—occurs "through equipment design or operational practices, such as the continuous bleed of gas from pneumatic devices (that control gas flows, levels, temperatures,

18. The U.S. Environmental Protection Agency, "Overview of the Oil and Natural Gas Industry", https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry#sources.

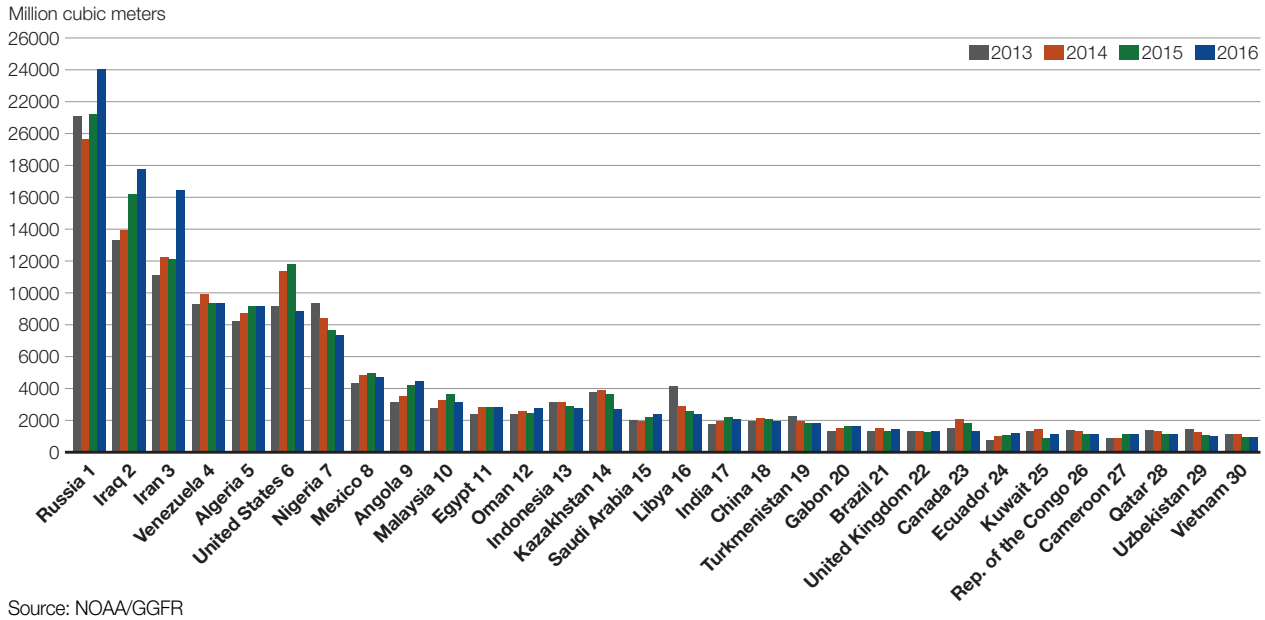
19. U.S. Environmental Protection Agency, "Overview of the Oil and Natural Gas Industry", https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry#sources.

and pressures in the equipment), or venting from well completions during production".[20] Venting can be reduced through management practices and use of technologies that separate, capture, and route gas to flares, pipelines, and devices that enable onsite use of captured gas and reinjection of gas into the well. (Figure 7.) EPA has documented numerous such technologies. [21]

Fugitive emissions "can occur from leaks…in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment".[22] Such emissions can be identified and remedied through leak detection and repair programs.

Flaring is the burning of methane not captured for sale or for onsite generation of energy. The United States is the sixth-ranked country in the world in terms of amount of gas flared in oil production operations (Figure 5), but the U.S. flaring intensity rate—the amount of gas flared per amount of oil produced—is now below the rate of the world's top 10 oil-producing countries.[23] (Figure 6.)

FIGURE 5
TOP 30 FLARING COUNTRIES (2013-2016)



Source: NOAA/GGFR

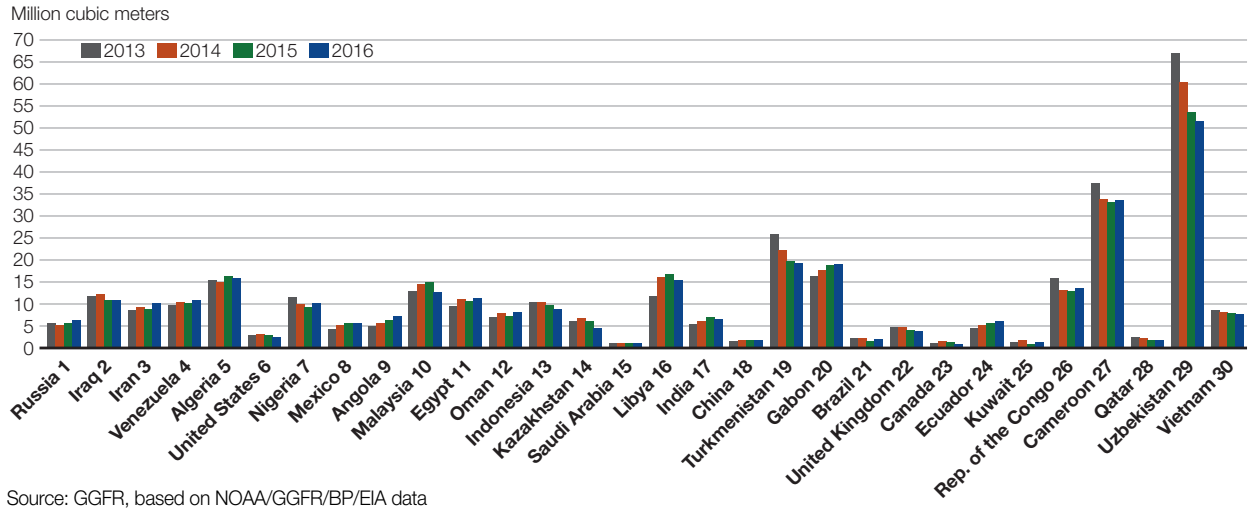
20. U.S. Environmental Protection Agency, "Overview of the Oil and Natural Gas Industry", https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry.

21. For example, technologies that might be applied to reduce venting include methods for improved storage vessels, compressors, pneumatic controllers, and pneumatic pumps. Other sources where reductions can be achieved include fugitive emissions from well sites and the gathering and boosting stations used to move production from the well pad onward. See U.S. Environmental Protection Agency, "Control techniques guidelines for the oil and natural gas industry", 2016, https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf. (Note: This guidance document has been withdrawn from the EPA website by the Trump Administration.) Similarly, EPA's Natural Gas STAR Program, a long-running partnership with volunteering oil and gas companies, has published a series of "lessons learned" documents for various technologies that summarize savings, costs, and payback periods based on company experiences. See, for example, fact sheets and "lessons learned" documents available here: "Natural gas STAR program recommended technologies for reducing methane emissions", https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions.

22. Supplementing U.S. EPA's description of venting in the text, CDP, which gathers emissions management and data for multiple sectors globally, describes venting as "intentional processing venting, arising from process, maintenance, turnaround and other non-routine and other activities". CDP distinguishes vented emissions from fugitive emissions, which it describes as coming from unintentional leaks or system malfunctions. See CDP, "Oil & Gas Sector Module 2016, Guidance for Responding Companies: Sector Module Guidance", 2016, pp. 13-14, https://www.cdp.net/Documents/Guidance/2016/CDP-2016-Oil-Gas-Module-Reporting-Guidance.pdf.

23. The World Bank, "Global Gas Flaring Reduction Partnership (GGFRP)", http://www.worldbank.org/en/programs/gasflaringreduction#7.

FIGURE 6
FLARING INTENSITY — TOP 30 FLARING COUNTRIES (2013-2016)
Cubic meters gas flared per barrel of oil produced



Source: GGFR, based on NOAA/GGFR/BP/EIA data

Regarding climate change impacts, flaring is preferable to venting because the carbon dioxide released after burning methane in flares has much less "global warming potential" than methane released directly into the atmosphere.[24] This is particularly true when calculated for impacts over a shorter term (the next 20 years) as compared to a longer term (the next 100 years). If a flare does not operate efficiently or if it malfunctions, however, it can release unburned methane into the atmosphere. More preferable to flaring is capturing methane for productive sale or use so that the methane is consumed by an end user as part of energy consumption, rather than being released or burned as waste.

Venting and flaring are addressed by both federal regulations and regulations in many oil- and gas-producing states. For example, EPA's New Source Performance Standards (NSPS) for the oil and gas industry require companies to use "green completions" (also known as reduced emission completions) in which companies must use, or route to a sales pipeline, gas that otherwise would be vented or flared. The NSPS apply to new and modified sources, with some exceptions. EPA's 2012 NSPS regulations apply only to new and modified gas wells. The regulations allow for flaring during a three-year transition period, after which no flaring is allowed.[25] In 2016, EPA extended its green completion requirements to new and modified oil wells.[26] Complementary state regulations also ban or restrict venting.[27] North Dakota's regulations are especially noteworthy. In 2014 North Dakota established deadlines for companies producing oil from the Bakken play to substantially reduce flaring from the rapid proliferation of new oil wells.[28] The new regulations promote more rapid and timely construction of gathering line and gas processing plant infrastructure to capture and process the gas associated with oil production.

24. The Global Warming Potential (GWP) for a gas is a measure of the total energy that a gas absorbs over a particular period of time compared to carbon dioxide. The larger the GWP, the more warming the gas causes. See U.S. Environmental Protection Agency, "Atmospheric Lifetime and Global Warming Potential Defined", https://www.epa.gov/climateleadership/atmospheric-lifetime-and-global-warming-potential-defined.

25. U.S. Environmental Protection Agency, "Summary of Requirements for Processes and Equipment at Natural Gas Well Sites", 2012, https://www.epa.gov/sites/production/files/2016-09/documents/20120417_natural_gas_summary_gas_well.pdf.

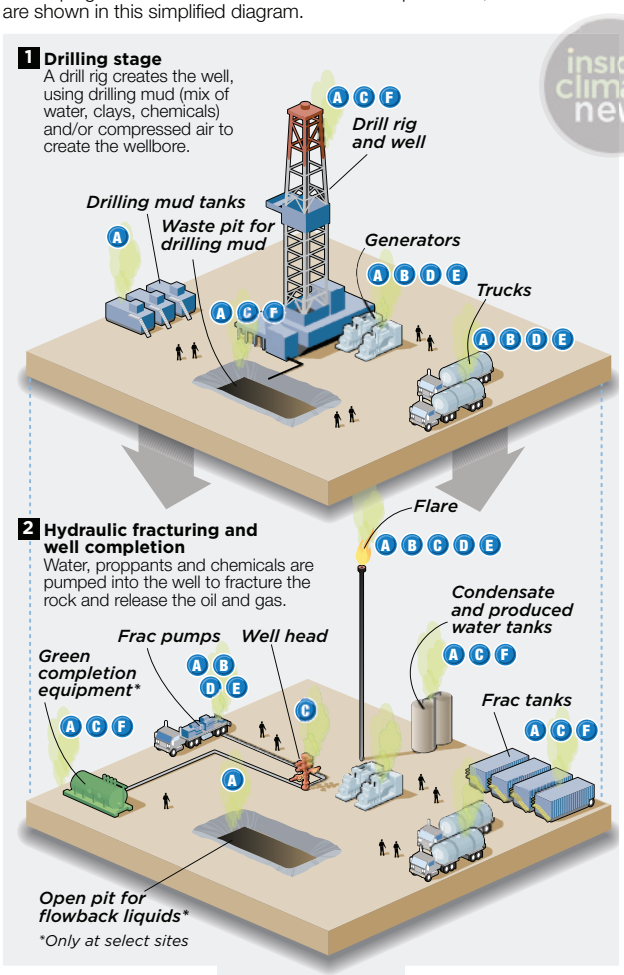
26. U.S. Environmental Protection Agency, "Summary of Requirements for Processes and Equipment at Natural Gas Well Sites," 2016, https://www.epa.gov/sites/production/files/2016-10/documents/nsps-oil-well-fs.pdf.

27. See Resources for the Future, "The State of State Shale Gas Regulation", 2013, pp. 59-62, http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-Rpt-StateofStateRegs_Report.pdf. For a summary of Texas rules from both the Texas Railroad Commission and the Texas Commission on Environmental Quality, see https://hy-bon.com/blog/texas-venting-and-flaring-of-natural-gas-permitting/.

28. The state regulations limit flaring at new and existing wells, with the goal of reducing the amount of gas flared from 30 percent in 2013 to 23 percent by 2015 and to 10 percent by 2020. See "North Dakota regulator sets new gas-flaring rules", *Wall Street Journal*, 2013, https://www.wsj.com/articles/north-dakota-regulator-sets-tough-gas-flaring-rules-1404257684.

Air Emissions from Oil and Gas Development in the Eagle Ford

There are more than 7,000 oil and gas wells in the Eagle Ford Shale, and Texas regulators have approved another 5,500. Most of them, like the one shown here, are oil wells that also produce condensate and natural gas. Developing these resources releases various air pollutants, some of which are shown in this simplified diagram.



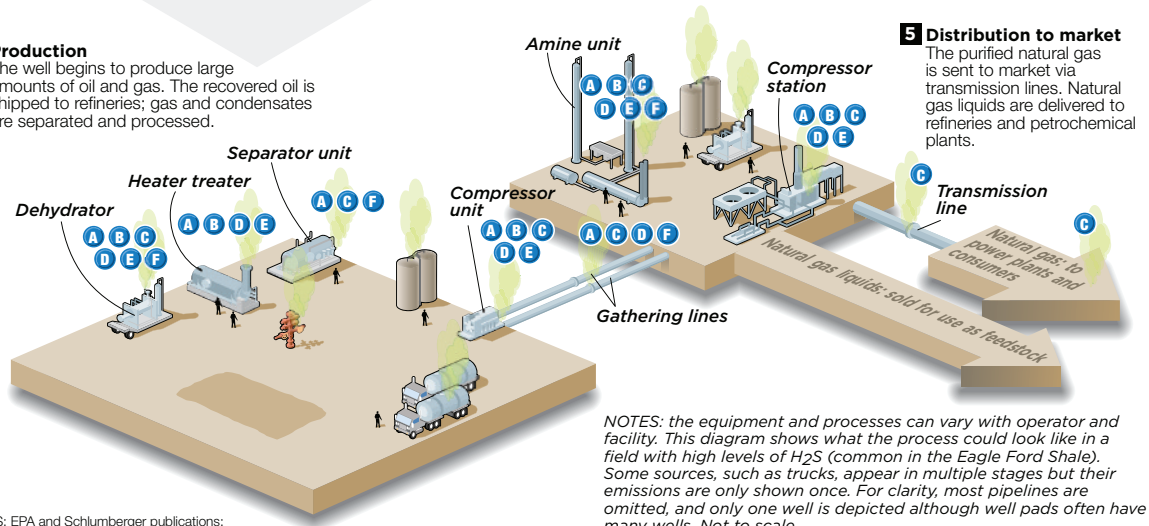
Emission Sources

The pollutants come from a number of sources, including the diesel- or natural gas-fueled equipment, the oil and gas itself, and leaks from storage devices. The emissions' actual and relative amounts vary widely based on operator practices and local geology. The emissions occur regularly in some cases, but are intermittent in others.

CHEMICAL	WHAT IT IS	WHAT IT DOES
A VOCs	Volatile organic compounds including benzene, formaldehyde	There are dozens of VOCs that make people sick. Some can cause cancer. VOCs react with NOx to form ozone, a respiratory irritant and greenhouse gas.
B PM	Particulate matter	Affects the heart and lungs.
C CH_4	Methane	Main component of natural gas. Much more powerful than CO_2 as a greenhouse gas.
D CO_2	Carbon dioxide	Major greenhouse gas.
E NOx	Nitrogen oxides	Reacts with VOCs to create ozone.
F H_2S	Hydrogen sulfide	Toxic gas found in some gas fields. Causes illness and death at certain concentrations.

Fugitive emissions: pipelines, valves, pneumatic devices etc. leak methane, VOCs, H_2S and CO_2 throughout the entire process.

4 Dehydration, treatment and processing
Water, condensate, H_2S and other impurities are taken out of the raw natural gas. This can occur on or near the well pad or at a centralized processing facility. Additional equipment used to purify and process natural gas liquids is not shown here.



NOTES: the equipment and processes can vary with operator and facility. This diagram shows what the process could look like in a field with high levels of H_2S (common in the Eagle Ford Shale). Some sources, such as trucks, appear in multiple stages but their emissions are only shown once. For clarity, most pipelines are omitted, and only one well is depicted although well pads often have many wells. Not to scale.

SOURCES: EPA and Schlumberger publications; experts consulted for various aspects of the diagram include Ramón Alvarez (EDF), Richard Haut and Jay Olaguer (HARC), Alisa Rich (UNT), Jim Tarr (Stone Lions Env. Corp), engineers from industry and Cardno Entrix.

Research by LISA SONG / InsideClimate News Graphic by PAUL HORN / InsideClimate News

IMAGE: Paul Horn / Inside Climate News

NATURAL GAS: BETTER THAN COAL?

Hydraulic fracturing is performed to release oil and gas from so-called "unconventional resources"—shale and other geological formations—from which oil and gas are difficult to retrieve without fracturing.[29] Over a relatively short period, oil and gas from hydraulic fracturing have become more of the norm than "unconventional"; the U.S. Energy Information Administration reports that in 2015 "unconventional resources" yielded approximately two-thirds of the natural gas and roughly half of the oil produced in the United States.[30]

The extraordinary success of oil and gas companies in developing shale and other unconventional resources has massively increased natural gas supply relative to demand, lowering U.S. gas prices and encouraging power generators to substitute gas for coal in electricity generation. In 2016, natural gas was used to produce approximately 34 percent of U.S. power, surpassing coal on an annual basis.[31] When burned to generate electric power, natural gas produces approximately 50 percent of the carbon dioxide emissions of coal per unit of energy produced.[32] This advantage, however, can be reduced by sizeable leaks of methane across the natural gas value chain, from production to the end user.

Scientists estimate that to retain natural gas' advantage over coal for power generation, leaks and other emissions must be limited to 3.2 percent from the wellhead to the power plant.[33] Uncertainty over the amount of leakage of methane during the natural gas life cycle contributes to the current policy debate over whether natural gas is a bridge to an energy future based on renewable energy or a bridge to nowhere. While this debate, driven by many economic, technological, and policy variables, is beyond the scope of this report, the issue of leaks in upstream oil and gas production is important enough that *DTF 2017* focuses on disclosures of management steps to prevent and reduce methane emissions.

EFFECTIVE PRACTICES FOR METHANE EMISSIONS CONTROL

Figure 7 describes some of the recommended practices available for addressing major sources of methane emissions. For example, pneumatic devices which release or bleed natural gas to the atmosphere as part of normal operations are a major source of methane emissions. "Low bleed" pneumatic controllers release fewer emissions and can be substituted for "high bleed" pneumatic controllers. Pneumatic controllers powered by compressed air can be an even better substitute, releasing air rather than compressed natural gas to dramatically reduce emissions from the equipment.[34] Vapor recovery units for capturing gas can be used to lower emissions from a range of facilities. A variety of "artificial lift" technologies can be used to minimize emissions from unloading processes associated with certain liquids.[35]

29. *DTF 2017* refers to these various geological formations collectively as "shale".

30. U.S. Energy Information Administration, "Hydraulically fractured wells provide two-thirds of U.S. natural gas production", 2016, https://www.eia.gov/todayinenergy/detail.php?id=26112.

31. U.S. Energy Information Administration, "What is U.S. electricity generation by energy source?", https://www.eia.gov/tools/faqs/faq.php?id=427&t=3. See also U.S. Energy Information Administration, "Competition between coal and natural gas affects power markets", June 2017, https://www.eia.gov/todayinenergy/detail.php?id=31672&src=email.

32. National Energy Technology Laboratory (NETL), *Cost and performance baseline for fossil energy plants, Volume 1: Bituminous coal and natural gas to electricity*. Revision 2, 2010, https://data.globalchange.gov/report/doe-netl-2010-1397. We note that renewable energy sources will generally have substantially less global warming potential than natural gas.

33. R. Alvarez, et al., "Greater focus needed on methane leakage from natural gas infrastructure," *Proceedings of the National Academy of Sciences (PNAS)*, 2012, http://www.pnas.org/content/109/17/6435.full. Knowledgeable experts are continuing efforts to refine the percentage limit figure, with some parties contending the percentage should be lower.

34. The compressors used for this equipment are powered by electricity that may be produced by solar power or sourced from the electric grid. Such compressors must be designed to ensure operation in cold weather.

35. Liquids unloading is the process by which accumulated liquids in a producing well are removed, allowing continued production.

FIGURE 7

Source of Emissions	Technology/ Practice Soution	Description	Development	Notes
Fugitive Emissions (i.e. unintended leaks)	Leak, Detection and Repair (LDAR)	The process of finding and fixing Fugitive emissions (i.e. leaks).	LDAR should be conducted at least quarterly on all assets using best available technology (i.e. wOGI infrared cameras).	ICF International Found LDAR to be the single biggest opportunity to reduce methane emissions. Many firms offer leak detection as a service, eliminating capital cost for operators.
High-bleed pneumatic controllers and pneumatic pumps	Low-bleed or intermittent pneumatic controllers/zero emissions alternatives	Pneumatics regulate process conditions and pump chemicals using the pressure of the gas which then "bleeds" (i.e. vents) into the atmosphere. Low or intermittent bleed emission values vent less gas than high-bleeds. Emission-free alternatives such as solar electric pumps have zero emissions.	Companies should always use low-bleed or intermittent pneumatics depending on which has lower emissions in a given situation and emissions-free alternatives where applicable. Companies should retrofit high-bleed pneumatics with lowering emitting options.	Sites with access to electricity access can eliminate pneumatic emissions by replacing with alternatives such as instrument air pneumatics or electric actuators and pumps.
Storage Tanks	Flares or Vapor Recovery Unit (VRU)	• Flares burn off emissions from tanks. It is the cheapest option, but still emits carbon dioxide emissions from combustion, and can emit methane from incomplete combustion. • VRU captures, compresses, and then directs emissions to a sales line. It is a higher cost, but results in no methane or carbon emissions.	All tanks emissions should be controlled. Deployment of flares vs. VRU will depend on size of tank and potential for emissions.	Flares and VRUs are only effective if properly designed and maintained. Operators should assure that tank control devices are adequately sized and frequently inspected to avoid issues such as unlit flares.
Liquids Unloading	Plunger Lifts	Plunger lifts are designed to improve productivity on older wells with water build up that limits gas flow.	While plunger lifts are one option used to remove water build up in wells, they also may limit emissions in the process compared to simply opening the well to atmospheric pressure to remove water.	Smart automation of plunger lifts and artificial lifts can reduce emissions in cases where plunger lift-equipped wells have high emissions.
Centrifugal Compressor Vents	Dry seal retrofit or vent gas capture	• Retrofit wet seal compressors with dry seals, which emit less emissions. • Gas capture controls vented gas by re-routing it to the compressor intake line.	All compressors should be controlled to limit emissions. Both options have similar economics and reduction potential, so operator will likely choose which is most optimal given operating conditions.	

Source: Principles for Responsible Investment and Environmental Defense Fund, "An investor's guide to methane: Engaging with oil and gas companies to manage a rising risk", 2016, p. 19, https://www.unpri.org/download_report/24246.

Considerable information has been accumulated on the costs of emission control technologies and the emission reductions achievable by applying such technologies. EPA's Natural Gas STAR program, a voluntary partnership of EPA and the oil and gas industry, has gathered much of this information.[36] Participating companies have implemented new emission reduction approaches, gathered emission reduction and cost estimates, and shared this information with U.S. EPA.[37]

36. See, for example, U.S. Environmental Protection Agency, "Recommended technologies to reduce methane emissions", https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions.

37. EPA reported that production companies participating in the Natural Gas STAR program since 1990 had reduced emissions by 943.6 billion cubic feet since 1990. EPA also reported that green completions yielded 32 percent of the emission reductions within the industry's production operations and replacement of high-bleed pneumatic controllers yielded an additional eight percent reduction in emissions. See U.S. Environmental Protection Agency, "Natural Gas STAR Program", https://www.epa.gov/natural-gas-star-program/natural-gas-star-program#domestic.

Benefits from emission control technology include not only lowering the climate change impact of oil and gas operations but also increasing revenues by capturing and selling methane rather than venting or flaring it.[38] Controls for methane emissions also control volatile organic compounds (VOCs) that can contribute to smog and toxic emissions known as hazardous air pollutants (HAPs).[39]

Some technologies can be more cost-effective to deploy than others. The cost-effectiveness and the length of the estimated payback period will depend on the costs of controls and the price of captured gas that is sold or used onsite to generate energy. This is demonstrated by the different conclusions reached in two studies performed by contractor ICF international in 2014 for EDF and in 2016 for the ONE Future Coalition.[40] The overall net benefits reported in the EDF report were greater than those in the ONE Future Coalition report.[41] The report for EDF used a sales figure for gas of $4/Mcf. The 2016 ICF report used a lower gas sales price ($3/Mcf), lowering the savings calculated.[42] The 2016 report also used higher emission control costs than those used in the 2014 report.

SHIFTING REGULATORY REQUIREMENTS AND PRIVATE SECTOR DEMANDS

Despite recent federal retrenchment on the Climate Action Plan and methane regulations,[43, 44] oil and gas companies remain under pressure to reduce their emissions. Multiple lawsuits are challenging the federal rollbacks. A growing

38. There can be associated revenue-sharing benefits for the federal government from controls deployed on federal lands. A 2015 report on emissions from federal and tribal land found that 65 billion cubic feet of natural gas, with an estimated value of $360 million, was released into the atmosphere in 2013 alone. See ICF International, "Onshore petroleum and natural gas operations on federal and tribal lands in the United States—analysis of emissions and abatement opportunities", 2015, https://www.edf.org/sites/default/files/content/federal_and_tribal_land_analysis_presentation_091615.pdf. Emissions represent potential revenues lost to both producers and the U.S. government from gas not placed into a pipeline for sale, because the U.S. government levies a 12.5 percent royalty fee on production. See U.S Government Accountability Office, "Oil, Gas, and Coal Royalties, Raising federal rates could decrease production on federal lands but increase federal revenue", 2017, p. 7, https://www.gao.gov/products/GAO-17-540.

39. HAPS include benzene, toluene, ethylbenzene, and xylene, commonly referred to as BTEX chemicals.

40. ONE Future companies, which include participants from across the natural gas value chain, have voluntarily committed to a goal of reducing methane leakage across the natural gas value chain to a total of 1.00 percent by 2025. The target committed to by ONE Future upstream companies is 0.36 percent or less of methane emitted from gross methane production by 2025. Each of these companies reports its methane emissions relative to this goal. Apache, BHP, Hess, Southwestern Energy, and Statoil are upstream members of the ONE Future Coalition. In conjunction with the coalition, EPA has developed a ONE Future Emissions Intensity Commitment Option as an approved voluntary program under its Methane Challenge program. See https://www.epa.gov/newsreleases/epa-announces-first-one-future-commitments-under-methane-challenge-program and https://www.epa.gov/sites/production/files/2017-10/documents/methanechallengefactsheet.pdf.

41. See ICF International, "Economic analysis of methane emission reduction opportunities in the U.S. onshore oil and natural gas industries", prepared for the Environmental Defense Fund, 2014, https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf and ICF International, "Economic analysis of methane emission reduction potential from natural gas systems", prepared for ONE Future Inc., 2016, http://www.onefuture.us/wp-content/uploads/2016/06/ONE-Future-MAC-Final-6-1.pdf.

42. The U.S. average gas price in 2014 was above $4/Mcf but since then gas prices have been closer to $3/Mcf or below. See U.S. Energy Information Administration, "Natural gas monthly September 2017", p. 7, https://www.eia.gov/naturalgas/monthly/pdf/ngm_all.pdf. The two reports also used EPA gas inventories from different years.

43. https://obamawhitehouse.archives.gov/the-press-office/2013/06/25/fact-sheet-president-obama-s-climate-action-plan.

44. The New York Times, in a story on Trump Administration efforts to roll back Obama-era regulations such as the Clean Power Plan regulation on power plant carbon emissions, reported that rollbacks could take years because of the review and comment process that must be observed when substantively changing regulations and because the proposed changes are being litigated, a process that can take three years or more to complete. See "Court blocks E.P.A. effort to suspend Obama-era methane rule", *New York Times*, 2017, https://www.nytimes.com/2017/07/03/climate/court-blocks-epa-effort-to-suspend-obama-era-methane-rule.html. The Trump Administration's revocation of the Obama Administration's Climate Action Plan, which would have reduced methane emissions from the oil and gas sector by 40-45 percent from 2012 levels by 2025, will leave a serious void of uncertain size if upheld. The Trump Administration is also attempting to roll back other federal regulations that limit methane emissions and has declared that the United States will withdraw from the Paris climate accord. The impact of these actions on future trends in natural gas production and use is difficult to determine, but might be modest relative to other marketplace drivers due to state and local regulations that are in place or being proposed. For an overview of many of the data supporting this conclusion, see "The Green Energy Revolution Will Happen Without Trump", *New York Times*, 2017, https://www.nytimes.com/interactive/2017/06/20/opinion/green-energy-revolution-trump.html. See also "Power companies to stick with plans despite EPA's emissions repeal", *Wall Street Journal*, 2017, https://www.wsj.com/articles/epa-moves-proposal-to-withdraw-obama-power-plant-rules-1507657014.

number of major oil-producing states and provinces, including California, Colorado, Wyoming, Ohio, Pennsylvania, and Alberta, have adopted or are in the process of adopting regulatory controls on methane emissions including requirements for Leak Detection and Repair (LDAR) programs. (See sidebar and Figure 8.) Nations, states, cities, and major businesses have stated their strong support for the Paris agreement, signaling greater focus on reducing greenhouse gas emissions.[45]

Contributing further to the pressure on the oil and gas industry, a "who's who" of major Fortune 100 companies have declared strong, time-limited goals for substituting renewable energy sources such as wind, solar, and hydro power, for oil, gas, and coal. Many more are moving to reduce their own emissions, including emissions from power use and vehicles.[46] These public and private sector actions can reduce demand for oil and gas domestically.[47]

THE TIGHTENING REGULATORY ENVIRONMENT

In 2016, as part of its updated New Source Performance Standards (NSPS) for the oil and gas industry pursuant to the Clean Air Act, U.S. EPA published nationally applicable regulations requiring companies to develop Leak Detection and Repair (LDAR) programs for new and modified natural gas and oil well sites.[48] These regulations require companies to report any leaks found within 30 days in most circumstances. The regulations also extend to new and modified oil wells requirements for "reduced emission completions" or "green completions" that previously had applied only to new and modified natural gas wells.[49]

Several states have adopted their own LDAR requirements for methane emissions from the oil and gas industry. In 2014 the State of Colorado adopted regulations, developed in collaboration with EDF, Anadarko, Encana, and Noble Energy, that require companies to report to regulators annually on their implementation of LDAR

Continued on next page.

45. See, for example, the United States Climate Alliance, a coalition of states committed to reducing greenhouse gas emissions consistent with the Paris climate agreement: https://www.usclimatealliance.org/. See also "America's Pledge on Climate", a coalition of businesses and governments similarly committed to greenhouse gas reductions: https://www.americaspledgeonclimate.com/. The America's Pledge group reports that if these non-federal actors were a country, their economy would be the third largest in the world, bigger than all but two national parties to the Paris agreement. The report finds further that 20 U.S. states, 110 U.S. cities, and over 1,300 businesses with U.S. operations have adopted quantified emissions reduction targets representing USD $25 trillion in market capitalization and nearly 1.0 gigatons of GHG emissions per year. See America's Pledge, "America's Pledge Co-Chairs Mike Bloomberg and Governor Jerry Brown reaffirm U.S. commitment to Paris Agreement on Climate Change, present report on U.S. climate action at UN talks", https://www.bbhub.io/dotorg/sites/28/2017/11/AmericasPledgePhaseOneReportWeb.pdf.

46. See "Biggest U.S. companies setting more renewable-energy targets", *Bloomberg*, 2017, https://www.bloomberg.com/news/articles/2017-04-25/biggest-u-s-companies-setting-more-renewable-energy-targets.

47. These reductions have some potential to be offset by growing exports of U.S. oil and gas overseas. See, for example, "Oil exports, illegal for decades, now fuel a Texas port boom", *New York Times*, 2017, https://www.nytimes.com/2017/07/05/business/energy-environment/oil-exports-corpus-christi-texas.html?_r=0. Whether such exports will increase use of oil and gas overall or simply replace other sources remains to be seen as policies to reduce greenhouse gas emissions are put in place globally.

48. See U.S. Environmental Protection Agency, "Summary of requirements for processes and equipment at natural gas well sites", 2016, https://www.epa.gov/sites/production/files/2016-10/documents/nsps-gas-well-fs.pdf. The Trump administration proposed a 90 day suspension of some components of the new standards and opened for public comment a proposal to suspend them for two years. The 90 day suspension was rejected by a panel of the D.C. Circuit Court of Appeals in a 2-1 decision. See "Court blocks E.P.A. effort to suspend Obama-era methane rule", *New York Times*, 2017, https://www.nytimes.com/2017/07/03/climate/court-blocks-epa-effort-to-suspend-obama-era-methane-rule.html. On the proposed two year suspension, see U.S. Environmental Protection Agency, "Oil and natural gas sector: Emission standards for new, reconstructed, and modified sources: stay of certain requirements", 2017, https://www.federalregister.gov/documents/2017/11/08/2017-24344/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources-stay-of.

49. Green completions deploy emission capture and processing technology on well pads to capture and route to pipelines methane that otherwise would be vented or flared.

Continued from previous page.

programs, including inspection methods and numbers of component leaks identified and repaired.[50] Wyoming and Ohio, following Colorado's lead, similarly adopted requirements for leak detection and repair programs. In 2016, Pennsylvania Governor Tom Wolf announced a methane reduction regulatory program for Pennsylvania oil and gas producers that includes use of best management practices, enhanced leak detection and repair programs, and related measures.[51] Regulations to implement the plan were released for public comment in early 2017.[52]

California has adopted a statewide methane reduction goal of 40 percent below 2013 levels by 2030.[53] In March 2017, the California Air Resources Board approved new regulations to improve LDAR programs and increase capture of methane. The regulations require quarterly monitoring of methane emissions from oil and gas wells, natural gas processing facilities, compressor stations, and other equipment in the natural gas value chain. Vapor collection systems will be required for some types of equipment.

In May 2017, as part of a climate change plan, Canada's federal government announced draft rules to reduce methane emissions for the oil and gas sector by 40-45 percent from 2012 levels by 2025—the same targets established by the Climate Action Plan withdrawn by the Trump Administration.[54] Canadian officials state that the new rules will address more than 95 percent of oil and gas industry methane emission sources.

The Province of Alberta, Canada, has established a goal of reducing methane emissions by 45 percent by 2025. (Alberta's oil and gas sector accounts for 70 percent of provincial methane emissions.)[55] Similarly, British Columbia announced its Climate Leadership Plan in 2016, which includes a goal to reduce methane emissions by 45 percent from the oil and gas sector by 2025. BC's methane reduction program includes limits on direct releases of methane to the atmosphere (venting), allowing such releases only under "the most exceptional circumstances."[56, 57]

50. See, for example, Anadarko, "LDAR annual report 2014", https://www.colorado.gov/pacific/sites/default/files/Anadarko_Reg_7_LDAR_Annual_Report_2014_rec_5-28-15.pdf. Colorado's regulations are accessible at https://www.colorado.gov/pacific/cdphe/emissions-requirements-oil-and-gas-industry.

51. See http://www.dep.pa.gov/Business/Air/Pages/Methane-Reduction-Strategy.aspx#.Vp6a0vkrJhE.

52. Pennsylvania Department of Environmental Protection, "A Pennsylvania framework of actions for methane reductions from the oil and gas sector", 2017, http://www.dep.pa.gov/business/air/pages/methane-reduction-strategy.aspx.

53. Livestock, particularly dairy cows, are the largest source of methane in the state, with the oil and gas industry responsible for about 15 percent of methane emissions. See "CARB approves rule for monitoring and repairing methane leaks from oil and gas facilities", https://www.arb.ca.gov/newsrel/newsrelease.php?id=907. See also California Air Resources Board, "Updated informative digest Regulation for greenhouse gas emission standards for crude oil and natural gas facilities", https://www.arb.ca.gov/regact/2016/oilandgas2016/oguid.pdf.

54. "New rules aim to cut methane emissions in Canada's oil, gas sector", *Toronto Globe and Mail*, 2017, https://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/new-methane-rules-aim-to-cut-emissions-from-canadas-oil-and-gas-sector/article35112124/.

55. Alberta Government, "Reducing methane emissions", https://www.alberta.ca/climate-methane-emissions.aspx.

56. British Columbia Government, "45% methane reduction strategy", https://climate.gov.bc.ca/feature/45-methane-reduction-strategy/.

57. For details of the criteria governing venting and flaring decisions, see BC Oil and Gas Commission, "Flaring and venting reduction guideline June 2016 version 4.5", 2016, http://www.bcogc.ca/node/5916/download.

FIGURE 8
LEADING STATE LEAK DETECTION AND REPAIR (LDAR) REGULATORY PROGRAMS, AS OF MARCH 2017[58]

Jurisdiction	Regulatory Agency	Regulation Name	Regulation Status	Well Type Addressed	LDAR Testing Frequency	Current Regulatory Leak Detection Technology	Pathway To Use Innovative Leak Detection Technologies
California	California Environmental Protection Agency and various local Air Pollution Control Districts	California Code of Rgulations, Title 17. Also see BAAQMD, SCAQMD and SJVAPCD local rules (among others) arising under California	Statewide regulations receiving public comments at time of report release, local rules formally adopted and in effect	New & Existing facilities	Quarterly	OGI and Portable Analyzers; mandates to measure leak concentration using portable analyzer technology	No
Colorado	Colorado Department of Public Health and Environment	Regulation 7, Section XVII	Established (2014)	New & Existing facilities	Frequency of inspection varies depending on facility type and size	OGI or Portable Analyzers	Yes
Pennsylvania	Pennsylvania Department of Environmental Protection	General Permit 5	Published (February 2017)	New & Existing facilities	Quarterly; frequency of inspection varies	OGI; allows use of AVO detection methods	No
Wyoming	Wyoming Department of Environmental Quality	Oil and Gas Production facilities Chapter 6, Section 2: Permitting Guidance	Established (2014)	New facilities in the Upper Green River Basin; existing facilities that emit certain levels of emissions in the Upper Green River Basin	Quarterly	Various; excludes AVO and other non-instrument-based methods	Yes
Ohio	Ohio Environmental Protection Agency	Ohio Administrative Code (OAC) Chapter 3745-77-11	Established (2014)	New & Modified facilities	Quarterly with stepdown provision based on number of leaking components	TBD	NA

Source: California Environmental Protection Agency, Colorado Department of Public Health and Environment, Ohio Environmental Protection Agency, Pennsylvania Department of Environmental Protection, Wyoming Department of Environmental Quality

58. Environmental Defense Fund/Datu Research, LLC, "Find and fix: job creation in the emerging methane leak detection and repair industry", 2017, p. 10, https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf.

LEAK DETECTION AND MEASUREMENT TECHNOLOGIES AND PROGRAMS

Figure 9 describes technologies currently available for detecting leaks.[59] They range from expensive, sophisticated infrared cameras that make air emissions otherwise invisible to the human eye visible, to non-technology-based (audio/visual/olfactory) efforts by company staff or contractors to hear, see, or smell emission problems. *DTF 2017* asks companies to disclose the technologies they use.

FIGURE 9

			Characteristics		
Technology		**Description**	**Indentifies Leak Presence**	**Pinpoints Leak Location**	**Quantifies Leak Concentration**
Optical Gas Imaging (OGI)	 Source: FLIR	Infrared camera providing real-time visualization of gas emissions and leaks.	●	●	
Portable Analyzers	 Source: PINE	Hand-held device measuring gas concentration through photoionization detection (PID), flame ionization detection (FID), infrared adsortion, or combustion.	●	●	●
Laser Spectroscopy	 Source: Heath Consultants	Laser shooting a specific wavelength that identifies methane presence.	●	●	●
Ambient Mobile Monitoring	 Source: Apogee Scientific	Mobile or stationery platform equipped with methane measurement instrumentation and GPS measuring ambient gas concentration.	●		●
Acoustic Leak Detection	 Source: Physical Acoustics	Method to identify leaks by detecting the sound of leaking gas.	●		
Audio-Visual-Olfactory (AVO)	 Source: Team Industrial Services	Combines three inspection methods: audio inspection (to hear leaking gas), visual inspection (to see visible ruptures in equipment) and olfactory inspection (to smell odor added to methane for safety).	●		

59. Environmental Defense Fund/Datu Research, LLC, "Find and fix: job creation in the emerging methane leak detection and repair industry", 2017, p. 8, https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf.

IMAGE: Flir.com

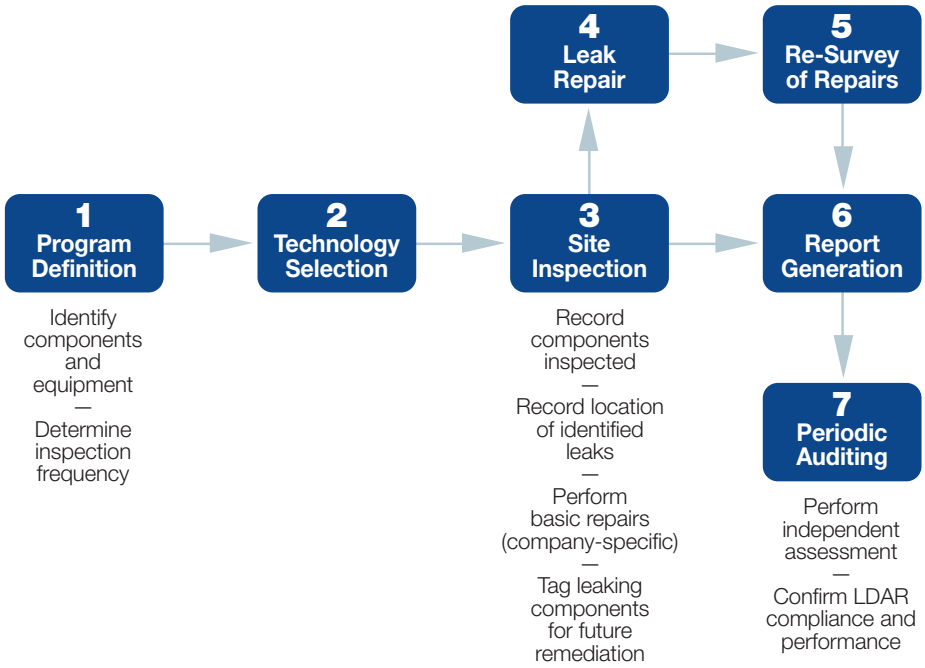
OGI camera

Growing interest in leak detection and repair provides a powerful incentive for innovative, entrepreneurial companies to lower the cost of leak detection technologies. New technologies are being evaluated as part of "The Methane Detectors Challenge", organized by EDF in 2014 in collaboration with oil and gas companies, academics, and technology creators.[60] The goal of the competition is to secure sensors at a reasonable cost that can detect methane at a level of two parts per million (2 ppm). Industry participants are currently testing two promising technologies. Similarly, in 2017, EDF, in collaboration with Stanford University's Natural Gas Initiative and advised by industry and other advisors, has launched the "Mobile Monitoring Challenge". The goal of this challenge is to evaluate methane-monitoring technology that can be deployed on drone, plane, motor vehicle, or other platforms to cost-effectively detect and quantify leaks.[61]

The rising demand for leak detection and repair is also creating jobs and fostering development of specialized leak detection businesses. One study found that at least 60 companies in 45 states provide such services to oil and gas companies. Most are small businesses experiencing sizeable growth, which is driving increases in well-paying jobs.[62]

Devising an effective LDAR program begins with describing a program's scope, including the facilities to be assessed, the frequency of inspection, and the type of inspection equipment. Companies decide on the technologies to be deployed and establish record-keeping systems to track inspections, repairs, and results and to generate reports for management and regulators. (Figure 10.)

FIGURE 10
MAJOR ELEMENTS OF LEAK DETECTION AND REPAIR PROGRAMS



Note: Adapted from "Leak Detection and Repair: A Best Practices Guide" by U.S. Environmental Protection Agency, 2007.

Source: Environmental Defense Fund[63]

60. Upstream oil and gas industry participants include Anadarko Petroleum, Hess Corporation, Noble Energy, Shell, Southwestern Energy, and Statoil. Similar work is being conducted by the Advanced Research Projects Agency-Energy (ARPA-E), a U.S. government program that advances high-potential, high-impact energy technologies that are too early for private-sector investment. See ARPA-E's MONITOR program, https://arpa-e.energy.gov/?q=arpa-e-programs/monitor.

61. B. Ratner and R. Alvarez, "Mobile monitoring challenge"(EDF blog), 2017, http://business.edf.org/blog/tag/mobile-monitoring-challenge/.

62. See Environmental Defense Fund/Datu Research, LLC, "Find and fix: job creation in the emerging methane leak detection and repair industry", 2017, https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf.

63. Environmental Defense Fund/Datu Research, LLC, "Find and fix: job creation in the Emerging methane leak detection and repair industry", 2017, p. 7, https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf.

DTF 2017 asks companies to describe their LDAR programs, including the facilities assessed, frequency of assessment, staff training, and speed of repairs. Analysis of this information helps companies assess where leaks are likely to appear in the future and how best to improve the effectiveness of LDAR programs. This information can also be used to improve maintenance programs that avoid leaks in the first instance or to establish more effective repair protocols.

IMAGE: Environmental Defense Fund

A solar-powered, continuous methane detection system, Eagle Ford, Texas

DATA UNCERTAINTIES—DETECTION/MEASUREMENT SYSTEMS ARE CRUCIAL TO CURBING METHANE EMISSIONS

The primary U.S. program for tracking greenhouse gas emissions from companies is the Greenhouse Gas Reporting Program established by EPA.[64] Companies report emissions data using estimated "emission factors" provided by EPA for the various pieces of equipment used.[65] Estimation methods have continued to evolve, with the latest estimates published in early 2017.[66]

Direct measurements of actual emissions have been used to adjust emission factors.[67] Increased measurement has been spurred by the exponential growth of shale gas and oil and by growing concern about climate change and air quality.[68] Collaborative measurement projects conducted by a partnership of EDF, companies, and academic researchers have yielded detailed studies published in peer-reviewed literature.[69] Complementary aerial data-gathering of emissions and atmospheric methane concentrations has been supported by the U.S. Department of

64. EPA tracks and reports U.S. greenhouse gas emissions and their sources through two complementary programs: the Inventory of U.S. Greenhouse Gas Emissions and Sinks (the Inventory) and the Greenhouse Gas Reporting Program (GHGRP). The two programs cover emissions from many of the same sources, but are not identical in their coverage, categorization, or methodologies. See https://www3.epa.gov/climatechange/ghgemissions/inventoryexplorer/data_explorer_flight.html.

65. See U.S. Environmental Protection Agency, "Basic Information of Air Emissions Factors and Quantification", https://www.epa.gov/air-emissions-factors-and-quantification/basic-information-air-emissions-factors-and-quantification and https://www.epa.gov/air-emissions-factors-and-quantification. EPA has also released "Procedures for the Development of Emissions Factors from Stationary Sources", https://www.epa.gov/air-emissions-factors-and-quantification/procedures-development-emissions-factors-stationary-sources.

66. U.S. Environmental Protection Agency, "Inventory of U.S. greenhouse gas emissions and sinks", https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks. The National Academy of Sciences is conducting a study of inventory uncertainties and methods for improvement, scheduled for publication in 2018. See "Anthropogenic methane emissions in the United States: improving measurement, monitoring, reporting, and development of inventories", http://nas-sites.org/dels/studies/methane-study/.

67. Informal comments to the authors signal that the updating has been a protracted, deliberative process.

68. See Environmental Integrity Project, "EPA agrees to re-examine smog-forming air pollution from drilling flares", Oct. 2016, https://www.environmentalintegrity.org/news/epa-agrees-to-re-examine-smog-forming-air-pollution-from-drilling-flares/.

69. As of mid-2016, 27 peer-reviewed papers had been published by project researchers, including 35 research institutions and over 120 co-authors. See M. Brownstein and S. Hamburg, "Keeping an important methane research question in proper perspective", 2016, *EDF Energy Exchange*, http://blogs.edf.org/energyexchange/2016/06/09/keeping-an-important-methane-research-question-in-proper-perspective/. For an update on studies see Environmental Defense Fund, "Methane research: the 16 study series", http://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

Energy, the National Oceanic and Atmospheric Administration (NOAA), and the National Aeronautics and Space Administration (NASA); some of these projects have involved collaboration with academics and companies.[70]

Experts continue to debate how much methane is released from gas and oil operations. Studies with estimates of emissions are continually produced through both "top-down" (satellites, airplanes, helicopters, and drones) and "bottom-up" (on-the-ground equipment) methods. Using more precise bottom-up measurements is important for multiple reasons, including to improve the accuracy of EPA's emission factors, help companies set equipment replacement, monitoring, and repair priorities, and promote smarter, focused regulation. Some studies conclude that the EPA inventory data understates total emissions from particular sources while others conclude the inventory overstates emissions. Both positions may be true; variation in these studies include the completeness and accuracy (inclusion/exclusion of sources) of the inventory, variations of emissions within a source category, the representativeness of emission samples, and how uncertainties are quantified.[71]

Bottom-up measurements have revealed the problem of "super-emitters"—a small number of components with significant leaks that produce a disproportionately large portion of emissions. A 2016 review of 15,000 measurements from 18 prior studies concluded that five percent of leaks contributed to 50 percent of leak volume.[72] Greater frequency of, and more targeted, monitoring may help address the potential for large leaks to go undetected for long periods of time.

A study of air emissions in the Barnett Shale in Texas, published in late 2015, found that due to super-emitters, "at any one time", two percent of oil and gas facilities accounted for about half of emissions, with 10 percent responsible for 90 percent of emissions.[73] High-emitters are divided about equally among production sites, compressors, and gas processing plants. The researchers characterized the high-emitters as "spatiotemporally variable", meaning that at any time, some two percent of the facilities in the Barnett Shale are super-emitters, but at any other time a different combination of facilities can constitute the pool of super-emitters.[74] The researchers commented that this variability in emissions may stem from "avoidable operating conditions", i.e., malfunctions rather than permanent design flaws of equipment. Citing other studies, these "avoidable operating conditions" might include, for example, stuck valves or routine flashing "that could occur at any facility".[75] The researchers concluded that "to reduce these emissions requires operators to quickly find and fix problems". The study further concluded that methane emissions are 90 percent larger than estimates based on EPA's Greenhouse Gas Inventory (an inventory subsequently updated in 2017), corresponding to 1.5 percent of natural gas production.

70. See U.S. Department of Energy, "Methane Emissions", 2016, https://energy.gov/sites/prod/files/2016/08/f33/Methane%20Emissions.pdf and D. Zimmerle et al., "Reconciling top-down and bottom-up methane emission estimates from onshore oil and gas development in multiple basins: report on Fayetteville shale study", 2016, http://www.rpsea.org/media/files/project/5b5aa118/12122-95-FR-Unconventional_Greenhouse_Gas_and_Air_Pollutant_Estimates_in_DJ_Basin_V12_12-19-16.pdf.

71. For detailed technical discussion of these issues, see G. Heath et al., "Estimating U.S. methane emissions from the natural gas supply chain: approaches, uncertainties, current estimates, and future studies", 2015, *Joint Institute for Strategic Energy Analysis*, Technical Report NREL/TP-6A50-62820, http://www.nrel.gov/docs/fy16osti/62820.pdf.

72. See "'Super emitters' responsible for most US methane emissions", Phys.org, 2016, http://phys.org/news/2016-10-super-emitters-responsible-methane-emissions.html. The researchers also concluded that super-sensitive leak detectors might not be required across all operations because detecting these larger leaks may be accomplished through use of "less-sensitive but cheaper detection technologies [that] still find the majority of problem leaks". Research into the issue of when and how best to measure for leaks is ongoing. See also A. Brandt et al., "Methane leaks from natural gas systems follow extreme distributions", *Environmental Science & Technology*, 2016, http://pubs.acs.org/doi/abs/10.1021/acs.est.6b04303.

73. See D. Zavala-Araiza et al., "Reconciling divergent estimates of oil and gas methane emissions", *Proceedings of the National Academy of Sciences*, 2015, pp. 15597-15602, http://www.pnas.org/content/112/51/15597.full.pdf.

74. Although no single definition of "super-emitters" exists, and the total percentage of emissions they represent is likely to differ across time and place, there seems to be little debate that a relatively small number of sources contribute a large percentage of total emissions.

75. "Flashing" is a term that describes volatile components in a liquid suddenly emerging as a gas, for example when temperature is raised or pressure is reduced.

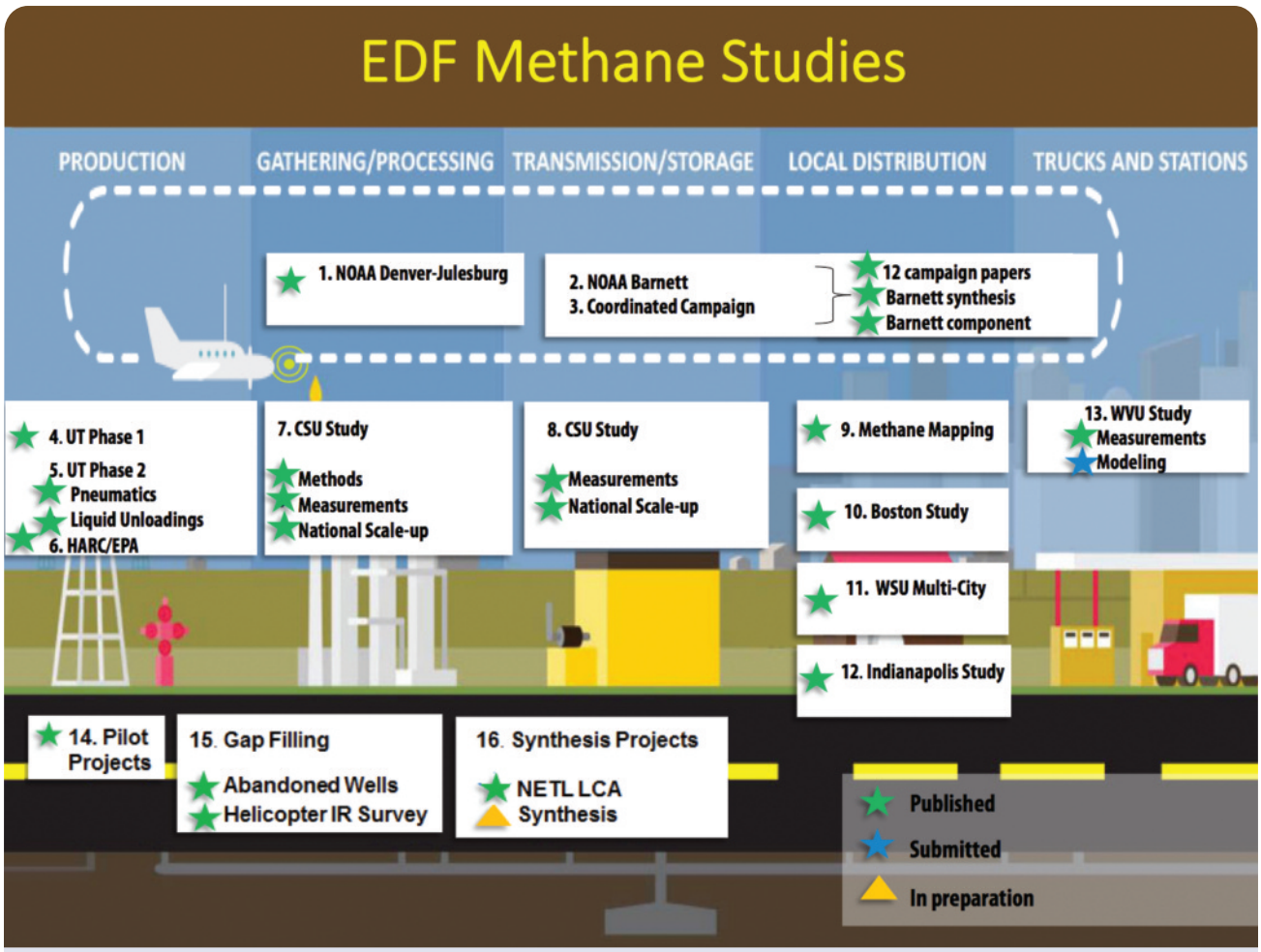


IMAGE: Environmental Defense Fund

Methane emission field studies

Researchers studying the Four Corners region in the Southwestern United States concluded similarly that a small number of sources contribute disproportionately to emission totals. The Four Corner region includes the San Juan Basin, a major natural gas production area. Using aircraft-based measurement technology, researchers concluded that 10 percent of emission sources (including gas processing facilities, storage tanks, pipeline leaks, well pads, and a coal mine venting shaft) accounted for about half of the observed point source contributions and roughly 25 percent of total basin emissions. Naturally occurring seeps from coal beds also contribute to the regional methane "hot spot" that researchers have identified.[76]

Research on the Fayetteville Shale in Arkansas provides insight into the differences between aircraft measurements and figures used in emissions inventories. A study, based on aircraft overflights, found that midday episodic emissions from routine operations could explain about one-third of the total emissions detected midday by the aircraft. This signaled that the aircraft might be detecting daily peak emissions rather than the daily averages that are generally employed in emissions inventories.[77]

76. See C. Frankenberg, et al., "Airborne methane remote measurements reveal heavy-tail flux distribution in Four Corners Region", 2016, *Proceedings of the National Academy of Sciences*, pp. 9734-9739, http://www.pnas.org/content/113/35/9734.full.

77. S. Schwietzke, et al., "Improved mechanistic understanding of natural gas methane emissions from spatially-resolved aircraft measurements," *Environmental Science and Technology*, 2017, http://pubs.acs.org/doi/abs/10.1021/acs.est.7b01810.

The disconnect between emission inventories based on emission factors and the growing body of evidence based on direct measurement of emissions underscores the urgency of developing inexpensive and cost-effective methane detection devices, especially continuous emission monitors that can swiftly detect an equipment malfunction leading to "super-emitter" levels of emissions. Until such technology is available, the data disconnect also indicates that more, rather than less, frequent routine monitoring should be the preferred option for LDAR programs. *DTF 2017* asks companies to report the proportion of their emissions reporting that is based on measurement and the proportion that is based on emission factors and other estimation tools.

SCORES–COMPANY DISCLOSURES OF METHANE REDUCTION PRACTICES

DTF 2017 builds upon the six methane-related questions found in prior *Disclosing the Facts* reports. These include questions regarding emission rates for methane relative to total methane produced; percentages or numbers of high-bleed pneumatic valves replaced; the scope and frequency of LDAR programs and the detection methods used; and setting of an active methane emissions reduction target and progress towards achieving it. Questions about emission rates and LDAR programs are similar to those used by CDP and EDF.

FIGURE 10
COMPANY SCORES

COMPANY	Andarko	Antero	Apache	BHP	BP	Cabot	Carrizo	Chesapeake	Chevron	Conoco	Consol	Continental	Devon	Encana	EOG	EQT	Exxon	Hess	Newfield	Noble	Occidental	Pioneer	OEP	Range	Shell	Southwestern	Whiting	WPX	TOTAL
Does the company describe its leak detection and repair program, including the facilities and assets covered by the program?		✓	✓	✓			✓	✓	✓	✓	✓		✓		✓			✓	✓	✓	✓	✓		✓	✓	✓		✓	19
Does the company describe the specific methodologies used (e.g. infrared camera, audio visual olfactory, continuous monitoring, stationary methane detectors) to identify methane leaks in its operations?	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓		✓		✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	24
For the specific methodologies described in Q3, does the company describe how frequently it uses each methodology and what proportion/percentage of each facility and/or asset is covered?				✓			✓	✓		✓	✓							✓	✓	✓		✓			✓	✓		✓	12
Does the company describe its leak repair procedure(s), principally the routine time period between leak detection and repair?	✓	✓	✓	✓			✓	✓		✓			✓				✓	✓	✓	✓				✓	✓	✓			15
Does the company describe its engineering and maintenance practices to, prevent, or minimize leaks?	✓	✓	✓	✓				✓									✓		✓	✓				✓	✓	✓		✓	12
Does the company describe the leak detection training it provides its operational/production staff, contractors who routinely visit well sites and/or are hired to conduct leak detection and repair, and staff trained specifically to conduct LDAR?			✓					✓		✓			✓		✓		✓	✓	✓			✓		✓	✓	✓			12
Does the company disclose an active, quantitative methane emissions reduction target, with timeline, and progress toward achieving this target?			✓	✓														✓								✓			4
Does the company describe its company-wide methane venting practices?	✓		✓	✓			✓			✓					✓	✓		✓		✓		✓		✓		✓			11
Does the company describe its company-wide methane flaring practices?			✓	✓				✓		✓	✓	✓			✓		✓	✓				✓		✓	✓	✓			13
Does the company report the percentage emissions rate for methane from its drilling, completion, and production operations, measured as methane emissions per methane production on an annual basis?			✓	✓	✓			✓		✓	✓		✓		✓		✓	✓	✓	✓		✓		✓	✓	✓			16
With respect to measuring methane emissions, does the company describe how it measures and reports emissions, including when it uses and reports actual measurements and when it estimates emissions using engineering calculations or emission factors?			✓	✓			✓	✓		✓	✓		✓			✓	✓	✓	✓	✓	✓	✓		✓	✓	✓			17
Does the company report the percentage or number of high-bleed controllers replaced with low-emission alternatives, or a program for their replacement?			✓	✓			✓	✓		✓	✓		✓				✓	✓	✓	✓		✓		✓	✓	✓		✓	16
Does the company disclose how it incentivizes greenhouse gas reductions at the board, management, and/or staff level through compensation structures?	✓		✓	✓	✓					✓								✓			✓				✓				8
TOTAL SCORE	5	4	12	12	3	0	7	10	2	11	7	1	7	0	6	1	9	11	10	9	4	9	1	10	11	12	1	5	

DTF 2017 adds seven new questions stemming from past corporate reporting and investor engagements with companies. These address repair times; training of personnel charged with leak detection; maintenance and engineering programs addressing emission points most susceptible to developing leaks; venting and flaring practices beyond compliance requirements; reliance on emission estimates and direct measurements for assessing emissions; and financial compensation incentives for corporate executives, managers, and staff to promote emissions reductions. Each company's response provides investors with insight into the quality of corporate management, commitment to methane emission reductions, and progress in reducing emissions.

Leak Detection and Repair (LDAR) Program Overview

Does the company describe its leak detection and repair program, including the facilities and assets covered by the program?[78]

Figure 10 displays the main stages and associated steps of an LDAR program. Company programs vary from those solely complying with state and federal regulatory requirements to broader voluntary leak detecting and monitoring programs.

This question asks companies to describe the facilities and assets addressed by their LDAR programs. Most companies discuss LDAR for well pads, compressors, and in some cases pipelines, while others discuss inspections of valves, flanges, and other components. Some report both ways. Many remain silent on practices beyond compliance with existing regulations and a few do not describe any LDAR program.

Scores

Fifteen (15) companies reported on their LDAR Programs.

Notable Practices

- *BHP* provides more detail on its LDAR program than any other company. It reports on a play-by-play basis the number and percentage of its facilities inspected by optical imaging cameras or by other methods. The company's LDAR program led to greenhouse gas reductions of 51,050 metric tons of CO2e in its 2017 fiscal year.[79]
- *Carrizo Oil & Gas* reports implementing a fugitive emissions monitoring program in Colorado and Texas, home to most of its oil production, prior to this being required by regulations. The program now covers operations in all of its plays, extending to the Marcellus and Utica. The company monitors more frequently than required by regulations. The company's description of its LDAR program is thorough; it states that it includes all wells, separation equipment, storage tanks, flowlines, dehydration units, piping, and ancillary equipment "from the wellhead to the sales meter at over 120 sites across [its] assets".[80]
- *Pioneer Natural Resources* implemented an LDAR program in Colorado beginning in 2011 covering well sites, tank batteries, compressor stations, and natural gas pipelines. The company has since extended its programs to all of its plays, including its sizeable activities in the Permian Basin. In 2016, the company's "thermographers" conducted optical gas imaging (OGI) surveys at more than 13,350 locations and an additional 130 miles of pipeline was inspected.[81]

78. The question refers to facilities and assets. Some companies refer to assets and others refer to facilities. This question treats these terms as interchangeable.

79. BHP, "Case study: Responsibly managing hydraulic fracturing", Oct.2017, p. 5, http://www.bhp.com/-/media/documents/environment/2017/171018_bhphydraulicfracturingcasestudy.pdf?la=en.

80. Carrizo Oil & Gas, "Environment", http://www.carrizo.com/sustainability/environment. Carrizo sold its Marcellus and Utica assets mentioned in the text in late 2017.

81. Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air.

- *Southwestern Energy*, which operates in the Fayetteville and Marcellus Shales, began a company-wide LDAR program in 2014 using a variety of detection instruments, including Bacharach Hi-Flow measurement devices to quantify the emissions detected. In 2016, Southwestern staff conducted instrument leak detection surveys on 99.9 percent of its total well count and 97 percent of its Midstream-operated compressor stations and repaired the leaks identified.[82]

IMAGE: Environmental Defense Fund

Field staff using OGI camera and high-flow sampler

LDAR Methods Used

Does the company describe the specific methodologies used (e.g., infrared camera, audio visual olfactory, continuous monitoring, stationary methane detectors) to identify methane leaks in its operations?

Some companies may rely broadly on optical infrared imaging cameras while others may make less use of these cameras and rely predominantly on Audio-Visual-Olfactory (AVO) detection methods by on-site workers. AVO involves listening and watching for gas, or detecting its smell,[83] while conducting other operational activities. Since the effectiveness of leak detection and monitoring methods can differ significantly, investors are interested in understanding what methodologies companies use.

Scores

Twenty-four (24) companies provided descriptions of specific leak detection technologies used.

Notable Practices

- *Pioneer Natural Resources* provides useful descriptions of how its leak detection devices work. It notes OGI (Optical Gas Imaging) cameras use infrared sensors that enable employees to see emissions that are not otherwise visible. It reports using Remote Methane Leak Detectors, which it describes as a laser-based technology that can quickly and efficiently detect leaks up to 100 feet away. Pioneer notes that, when some of the laser beam bounces back to the internal sensor, this can be used to calculate a methane concentration. The company further describes its testing of continuous emissions monitoring systems on tank batteries in the Permian Basin. These can quickly alert Pioneer to fugitive methane emissions, which may help the company to quickly locate unexpected emissions and better direct its LDAR program.[84]

IMAGE: Environmental Defense Fund

Optical gas imaging

82. Southwestern Energy, "Air", https://www.swn.com/responsibility/pages/air.aspx.

83. While pure methane is odorless, it is often mixed with odorous gases.

84. Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air.

LDAR Inspection Frequency

For each of the specific methods described, does the company describe how frequently it uses each and what proportion/percentage of each facility and/or asset is covered?

Federal and state regulations can vary in the frequency of inspections they require, as depicted in Figure 8. More frequent routine site visits, including monitoring, documentation, and repair of leaks, may lead to faster detection and repair of super-emitters. More frequent inspection may be most appropriate for those emission points known to be most leak-prone. Some states permit companies to taper inspection frequencies based on monitoring experience—if multiple, frequent inspections have not detected a leak problem, companies are allowed to reduce inspection frequency.[85] Although certain equipment may be more prone to failure, the accumulating evidence about the seemingly random occurrence of "super-emitters" suggests companies that voluntarily retain frequent inspections, aerial surveys, continuous monitoring, or other methods designed to identify leaks may achieve greater emission reductions. Incorporating measurement methods to the extent feasible will provide more accurate information as to the true extent of methane emissions; the number of leaks does not necessarily convey the volume of leaks. Increasing information on volume should provide more meaningful data.

Company responses to this question, with a few notable exceptions, tend to lack specificity as to what parts of the facility are being monitored, by what method, and at what frequency. Terminology differs from company to company and generalized statements are often made. As a result, shareholders are required to interpret as best they can what companies are actually monitoring, with what equipment, and how frequently. Although we have given credit to companies that at least broadly mention each of the criteria, in the future shareholders will seek greater specificity in company reporting, including more consistency in terminology, to create comparability in reporting on this important question.

Scores

Twelve (12) companies reported on the frequency of inspections.

Notable Practices

- *Chesapeake Energy* displays in a table the frequency with which it inspects well sites with Forward Looking Infrared (FLIR) cameras. The company reports on a play-by-play basis, noting which inspections are voluntary and which are required. The company declares that 65 percent of its inspections in 2016 were voluntary. The company also states that its operators conduct Audible, Visual, and Olfactory (AVO) observations as part of routine activities at well sites.[86]

- *Pioneer Natural Resources* prioritizes sites for inspection by cameras based on the potential for fugitive emissions to occur, inspecting them at least annually. Some, such as larger tank batteries and compressor stations have been identified as having a high potential for emissions and are surveyed semi-annually or quarterly.[87]

- *CONSOL* uses FLIR cameras monthly to detect fugitive emissions at its compressor stations while AVO inspections are conducted weekly at these stations. At its well sites, CONSOL uses FLIR cameras on a quarterly basis to detect fugitive emissions and conducts AVO inspections weekly.[88]

85. Reduced inspection frequency is permitted in Ohio, as shown in Fig 8. BHP reports being allowed under Texas regulations to reduce inspection frequencies in its Eagle Ford operations. See BHP, "Case study 2016: responsibly managing hydraulic fracturing", pp. 6-7, http://www.bhp.com/-/media/bhp/documents/society/reports/2016/161018_responsiblymanaginghydraulicfracturing.pdf?la=en.

86. Chesapeake Energy, "Preserving air quality", http://www.chk.com/responsibility/environment/air.

87. Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air.

88. See CONSOL Energy's response to OG7.3a, 2016 CDP Climate Change Report, http://2015crr.consolenergy.com/wp-content/uploads/CDP-Emissions.pdf.

Repair Time

Does the company describe its leak repair procedures, principally the routine time period between leak detection and repair?

The LDAR provisions of EPA's New Source Performance Standards for oil and gas wells specify that repairs must be made within 30 days unless the repair would require shutting down production.[89] In this case, companies must fix the leak at the next shutdown or within two years.[90] EPA indicates that equipment venting natural gas as part of normal operation is not considered to be leaking and is not covered by its requirement,[91] though leak surveys can help operators detect malfunctions in such venting devices, such as faulty pneumatic controllers. State regulations similarly establish time frames for making repairs.[92] Company staff, when they are able, should make repairs the same day leaks are detected, especially when staff or contractors are visiting sites with the specific mission of leak detection. Some companies have begun collecting and reporting statistics on repairs, providing both companies and investors with greater information about the effectiveness of their repair programs.[93]

Scores

Nineteen (19) companies reported on their repair practices.

Notable Practices

- *Antero Resources* reports that "in the vast majority of cases" repairs were made the same day leaks were detected.[94]
- *Carrizo Oil & Gas* attempts an immediate repair when leaks are found. If the repair cannot be done immediately, the leak is documented and a repair is scheduled as soon as possible.[95]
- *Newfield Exploration* personnel try to repair identified leaks while on site. If this is not possible, the leak is prioritized for repair according to federal and state regulations, with the goal to repair leaks within 30 days. The company reports that in 2016, through its LDAR program it repaired 2,500 leaks through 765 inspections at its operations in Utah and the Bakken; the leaks were detected via OGI cameras. Of the total repairs, 13 percent were voluntary.[96]

89. U.S. Environmental Protection Agency, "Summary of requirements for processes and equipment at natural gas well sites", 2016, https://www.epa.gov/sites/production/files/2016-10/documents/nsps-oil-well-fs.pdf and U.S. Environmental Protection Agency, "Summary of requirements for processes and equipment at oil well sites", 2016, https://www.epa.gov/sites/production/files/2016-10/documents/nsps-oil-well-fs.pdf.

90. Sites are not generally shut down solely to repair leaks since, when a site is shut down for maintenance, sizeable amounts of accumulated gases may be released to the atmosphere before work begins. This volume could easily exceed the emissions from an unrepaired leak occurring before the next scheduled shutdown.

91. Even low-bleed natural gas pneumatic controllers can emit sizeable amounts of natural gas if they malfunction. Some companies are installing solar-powered devices having no emissions, as discussed in the high-bleed pneumatic control question discussed below.

92. See, for example, the guidelines for Colorado's LDAR rules, https://www.colorado.gov/pacific/sites/default/files/AP_Memo-14-04-Reg7-LDAR-OpenEnd.pdf and Ohio Department of Natural Resources, "General permit 12.1 template high volume horizontal hydraulic fracturing, oil and gas well site production operations B. facility-wide terms and conditions", 2014, p.43, http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf.

93. See, for example, BHP's emission reductions reported in the text above as part of the company's description of its LDAR program.

94. Antero Resources, "Greenhouse gas", http://www.anteroresources.com/environmental-safety/greenhouse-gas.

95. Carrizo Oil & Gas, "Environment", http://www.carrizo.com/sustainability/environment.

96. Newfield Exploration Company, "Air quality & climate change", http://www.newfield.com/corporate-responsibility/safety-environmental/air-quality-climate-change.

Engineering and Maintenance

Does the company describe its engineering and maintenance practices to prevent or minimize leaks?

Some types of equipment may be more prone to failure than others. The rate of equipment failure can be a byproduct of the chemicals to which they are exposed while operating. Substances flowing from wells can vary in their corrosiveness, and equipment associated with wells pumping more corrosive materials may require enhanced maintenance or replacement schedules. Other equipment may fail randomly. Incorporating standard operating practices that include staff inspections combined with frequent maintenance may be effective in preventing some super-emitters. Many companies have accumulated considerable knowledge to establish robust maintenance programs and priorities, but they generally disclose little about them. Enhanced disclosures can provide investors greater insight into companies' maintenance cultures. Some companies also develop and may disclose specific engineering and equipment design practices that avoid or minimize emissions from routine operations. Ideally a strong maintenance and engineering program will perform preventive maintenance to prevent emissions and use LDAR data to prioritize future maintenance and prompt development of new equipment designs or technologies that prevent or minimize leaks.

Scores

Twelve (12) companies reported on their equipment engineering and maintenance practices.

Notable Practices

- *Antero Resources* conducts a maintenance program involving cleaning, greasing, and replacement of thief hatch seals and other measures to minimize storage tank leaks. It is also using newly designed thief hatches with improved seals. The company believes these efforts have led to a reduction in the leaks detected monthly under its LDAR program.[97]
- *Noble Energy's* ATLAS program, an alternative truck loading system for offloading oil from tanks to trucks in the DJ basin, now allows tank gauging and liquid sampling to occur without opening the thief hatch. The system uses automated systems, yielding both safety and environmental benefits. Noble trains its contract haulers to use the system, which is now used at 60 percent of the company's facilities. Noble also purges new facilities with nitrogen to detect and fix leaks prior to production.[98]
- *Anadarko Petroleum* uses improved tank battery design to reduce emissions.[99] The company states that tank battery design can reduce the potential for emissions from tank thief thatches, piping, and relief valves.[100] Any emissions are instead recovered and sold directly from a pressurized separator. Anadarko's Lease Automatic Custody Transfer (LACT) units sell produced hydrocarbons through pipelines as opposed to relying on oil haulers to bring them to the marketplace.
- *Apache* applies specific design standards and equipment for "severe service conditions", where the materials produced from a well are more corrosive.[101]

97. Antero Resources, "Greenhouse gas", http://www.anteroresources.com/environmental-safety/greenhouse-gas. Thief hatches are openings at tops of storage tanks that allow measurements to be taken.

98. See Noble Energy's response to Disclosing the Facts 2017, https://www.nblenergy.com/sites/default/files/Final%20-%202017%20Disclosing%20the%20Facts.pdf.

99. A tank battery is a group of tanks that are connected to receive crude oil production from a well or a producing lease. A tank battery is also called a battery. In the tank battery, the oil volume is measured and tested before pumping the oil into the pipeline system. See Schlumberger, "Oil Field Glossary", http://www.glossary.oilfield.slb.com/Terms/t/tank_battery.aspx.

100. Anadarko Petroleum, "Air-quality management", http://www.anadarko.com/Responsibility/Sustainable-Development/HSE/AirQuality-Management/.

101. Apache Corporation, "2017 Sustainability Report", p. 62, http://www.apachecorp.com/Resources/Upload/file/2017_SustainabilityReport_10_24_17.pdf.

- *Chesapeake Energy* uses maintenance data to identify preventive improvements to its sites. The company found that certain gaskets are prone to cracking and warping, so it notified responsible staff about the need to use alternative materials. Company staff also use an application on their smartphones to file real-time reports on air quality observations.[102]

- *Newfield Exploration's* LDAR program strategically targets facilities and equipment having the greatest potential for fugitive emissions. The strategy considers high-producing locations and sites with geographic proximity. Company personnel use tablet-based technology to log all camera and AVO inspections, identifying affected equipment and logging repair updates. The data are dispatched automatically to the company's compliance tracking system, enabling the company to analyze and respond to trends in equipment leaks.[103]

- *Southwestern Energy* uses its LDAR program to drive maintenance and repair practices based on data gathered. Southwestern cites the example of its midstream operations implementing a preventive maintenance program for liquid level controllers the company had identified as a potential source of leaks.[104]

- *ExxonMobil* uses its LDAR program for prioritizing leak sources. All leaks and repairs are tracked and analyzed for frequency, trends, and patterns. The company can then prioritize which facilities and types of equipment are most leak-prone, addressing these based on leak detection rates, repair time, costs, and manpower requirements.[105]

- *Range Resources* uses its OGI camera program to determine which components are most likely to leak. By analyzing that data and identifying trends, the company has been able to make substantial reductions in leaks by selecting alternative components and altering various processes.[106]

Training

Does the company describe the leak detection training it provides its operational/production staff, contractors who routinely visit well sites and/or are hired to conduct leak detection and repair, and staff trained specifically to conduct LDAR?

AVO methods are less robust than other detection methods such as OGI cameras but, in view of their widespread use, companies should provide information on how or if they specifically train staff to conduct AVO leak detection. Training for OGI camera operation is conducted by camera manufacturers and specialized training providers.[107]

Scores

Twelve (12) companies reported on training employees for leak detection.

102. Chesapeake Energy, "Preserving air quality", http://www.chk.com/responsibility/environment/air.

103. Newfield Exploration, "Air quality and climate change," http://www.newfield.com/corporate-responsibility/safety-environmental/air-quality-climate-change.

104. Southwestern Energy, "Achieving our Commitments: Corporate Responsibility Report Appendix 2016–17", p. 8, https://www.swncr.com/assets/files/appendix-2016-17.pdf.

105. ExxonMobil, "XTO Energy methane emissions reduction program", http://corporate.exxonmobil.com/en/energy/natural-gas/environment-and-safety/xto-energy-methane-emissions-reduction-program.

106. Range Resources, "Air quality best practices", http://rangeresources.com/corp-responsibility/environment-health-and-safety/air-quality-best-practices. On its website Range links to a paper by its staff presented to the Society of Petroleum Engineers that discusses equipment design improvements to reduce emissions. They concluded that implementation of an LDAR program reduces the number of leaks and allows for "a sustainable, cost-effective maintenance program". See M.D. Porter, et al., "Marcellus Shale production facility emissions: overcoming challenges in the liquids-rich area", SPE-184048-MS, 2016.

107. For examples of course and certification offerings, see http://www.flir.com/instruments/display/?id=54250; http://www.infraredtraining.com/; and https://www.thesnellgroup.com/infrared-training.

Notable Practices

- *Apache* provides AVO training for field employees as part of its overall competency training. New employees must demonstrate competency in safety and operating requirements, such as AVO inspections, before conducting fieldwork without the supervision of more experienced employees. Leak detection is an ongoing and regular part of Apache employees' onsite activities. Apache also routinely evaluates its contractors' training programs.[108]

- *Chesapeake Energy* sends its OGI camera operators for certification courses at the Infrared Training Center.[109] The company has developed lease operator guidebooks that include AVO observations. Lease operators conduct AVO operations as part of routine onsite activities. Through the company's mentoring program, lease operators receive onsite AVO training.[110]

- *Newfield Exploration* trains and certifies a company compliance team in use of OGI cameras and also provides training to all operation/production staff about common types of leaks, methods for testing and repair, and protocols for reporting.[111]

- *Pioneer Natural Resources'* OGI camera operators receive biennial training. The three-day course, for which certificates can be earned, addresses the gases that can be found and how different environmental conditions can make detection easier or harder.[112]

- *ExxonMobil* is developing a methane training component as part of the methane emissions reduction program at its XTO Energy unit. (XTO carries out the company's U.S. shale oil and gas operations.) The training will be for a broad range of company staff as well as those who may conduct inspections or be involved in qualifying and selecting contract leak detection and repair program survey firms. The company's existing optical gas imaging camera training program teaches the basics of camera operation and incorporates important operating considerations such as wind conditions, viewing distances, and temperatures.[113]

Methane Emissions Target

Does the company disclose an active, quantitative methane emissions reduction target, with timeline, and progress toward achieving this target?

Quantitative targets prioritize action, promote accountability, and facilitate tracking of progress. Some companies have expressed reluctance to establish public targets because of their shifting asset base. Asset transfers occur frequently within the industry as companies adjust their asset portfolios, dispose of less promising assets, and add more promising ones. As new operations are acquired, total emissions may increase. Investors are sufficiently sophisticated to understand how such an acquisition, or other such mitigating occurrences, might affect a company's achievement of its targets, when explained by the company. Thus, portfolio changes need not prevent adoption of targets.[114] Similarly, targets can be set in terms of methane emission intensity where simply acquiring assets will not

108. Apache Corporation, "2017 Sustainability Report", pp. 62 and 82, http://www.apachecorp.com/Resources/Upload/file/2017_SustainabilityReport_10_24_17.pdf.

109. Infrared Training Center, http://www.infraredtraining.com/.

110. Chesapeake Energy, "Preserving air quality", http://www.chk.com/responsibility/environment/air.

111. Newfield Exploration, "Air quality & climate change", http://www.newfield.com/corporate-responsibility/safety-environmental/air-quality-climate-change.

112. Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air.

113. ExxonMobil, "XTO Energy methane emissions reduction program", http://corporate.exxonmobil.com/en/energy/natural-gas/environment-and-safety/xto-energy-methane-emissions-reduction-program.

114. The ONE Future program was designed to account for not only acquisitions but also operational variability. A five-year weighted average provides for such variabilities. See ONE Future, "Methane emissions estimation protocol v.1", 2016, p. 15, http://www.onefuture.us/wp-content/uploads/2016/08/ONE-Future-Methane-Intensity-Protocol-v-1-2016.pdf.

necessarily contribute to higher emissions. Where acquired facilities have higher emissions intensity than current operations, companies can certainly provide such information to investors. In such cases, achieving a lower methane emission intensity level for the new facilities may appropriately take time and investment.

The vast majority of companies surveyed do not currently set methane reduction targets. Investors believe this is a missed opportunity because targets can be an important component in driving achievement.

Scores

Four (4) companies reported on setting an emission target.

Notable Practices

- *Apache*, *BHP*, *Hess*, and *Southwestern Energy* are founding upstream members of the ONE Future Coalition. Statoil joined ONE Future in 2017. Members of the coalition have committed to achieving a goal of less than 1.00 percent leakage across the entire natural gas value chain by 2025. Of the 1.00 percent leakage rate, 0.36 percent is allocated to the upstream oil and gas segment. Each of these oil and gas companies reports its methane emissions relative to this goal. Apache reports its 2016 emissions intensity as 0.43 percent, down from 0.49 percent in 2015 with an overall downward trend and decrease of 43 percent since 2012.[115] BHP reports its emissions intensity rates on a play-by-play basis, noting that its methane emissions occur predominantly from pneumatic controls and other fugitive emissions.[116] Southwestern Energy reports that it has achieved a methane leak/loss rate of 0.22 percent for combined production and midstream operations, below the ONE Future target of 0.36.[117] Hess reports a methane emissions rate for its 2016 production of 0.09 percent, well below the ONE Future goal for production.[118]

Venting

Does the company describe its company-wide methane venting practices?

Recognizing that many regulations ban or restrict venting, *DTF 2017* asks companies to discuss their "beyond compliance" venting practices. Investors assume companies comply with federal and state requirements unless evidence suggests otherwise. However, investors are interested in understanding when a company goes above and beyond regulatory requirements, especially with regard to venting. Further, while venting often is equated with lack of emissions capture equipment at wells, venting can also occur from a broad range of equipment across company facilities. This question seeks to understand where venting is occurring, for example at hatches, and what companies' company-wide policies are to reduce or avoid venting across the full range of operations.[119]

Scores

Eleven (11) companies reported on their venting practices.

Notable Practices

- *Carrizo Oil & Gas* reports having "a policy against venting produced gas under any circumstance", reciting a multitude of facility design measures to reduce such emissions. For instance, vapor recovery towers are used to reduce associated gas emissions from production tanks. Vapor recovery units are deployed where there is

115. Apache Corporation, "2017 Sustainability Report," pp. 62 and 66, http://www.apachecorp.com/Sustainability/index.aspx.

116. BHP, "Case study: responsibly managing hydraulic fracturing", Oct. 2017, http://www.bhp.com/-/media/documents/environment/2017/171018_bhphydraulicfracturingcasestudy.pdf?la=en.

117. Southwestern Energy, "Air", https://www.swncr.com/environment/air/index.html.

118. Hess, "2016 Sustainability Report", p. 45, http://www.hess.com/docs/default-source/gri/2016_hess_sustainability_report.pdf?sfvrsn=2.

119. *DTF 2017* seeks a description primarily of a company's programs and practices in the United States and Canada. Discussing only international activities is insufficient to earn credit.

sufficient gas to be sold. Condenser systems are used to eliminate the release of hazardous air pollutants, most notably BTEX chemicals. The company controls liquid load-outs from tanks to trucks[120] and routes vapors to flares if required.[121]

- *Apache* has a policy to avoid directly venting natural gas wherever practicable. Apache preferentially flares rather than vents gas, and only vents when dictated by safety or operational conditions. It has put practices in place to reduce emissions from planned events such as liquids unloading and compressor blowdowns. In 2016, its emissions from planned events were less than 0.50 percent of its total GHG emissions. The company uses special equipment and processes to capture emissions that are commonly released during production such as vapor recovery units, capturing tank emissions, and using plunger lifts to reduce methane emissions from gas well liquids unloading.[122]
- *Range Resources* reports that it goes beyond regulatory requirements in installing "closed loop systems" that route vented gas to enclosed burners or vapor recovery compressors. It also reports use of plunger lifts for liquids unloading, electric controls rather than pneumatic controllers, and glycol dehydration systems designed to use vented gas as fuel. Range also works directly with vendors in customizing equipment to minimize leaks and improve reliability. These include "industry-leading" tank valves that seal with a higher level of effectiveness.[123]
- *ExxonMobil* is reducing venting from liquids unloading—removal of liquid that has accumulated in tubing and prevents natural gas from flowing up through the well—by posting personnel to monitor the manual unloading process closely and to close all wellhead vents to the atmosphere.[124]

Flaring

Does the company describe its company-wide methane flaring practices, including success in reducing flaring?

DTF 2017's flaring question seeks a general discussion of a company's U.S. and Canadian practices, focusing on beyond-compliance flare management and flaring reduction practices. This question broadly seeks information on company policies, including for instance, whether routine flaring is prohibited and what exceptions a company may have adopted.

Scores

Thirteen (13) companies reported on their flaring practices.

IMAGE: FracTracker Alliance

Flare, Wessel County, VA

120. Simple connections can vent fumes to the atmosphere while more advanced loading systems allow for capture of these emissions.

121. Carrizo Oil & Gas, "Environment", http://www.carrizo.com/sustainability/environment. BTEX chemicals are benzene, toluene, ethylbenzene, and xylene.

122. Apache Corporation, "2017 Sustainability Report," pp. 62-65, http://www.apachecorp.com/Resources/Upload/file/2017_SustainabilityReport_10_24_17.pdf.

123. Range Resources, "Air quality best practices", http://rangeresources.com/corp-responsibility/environment-health-and-safety/air-quality-best-practices.

124. ExxonMobil, "XTO Energy methane emissions reduction program", http://corporate.exxonmobil.com/en/energy/natural-gas/environment-and-safety/xto-energy-methane-emissions-reduction-program.

Notable Practices

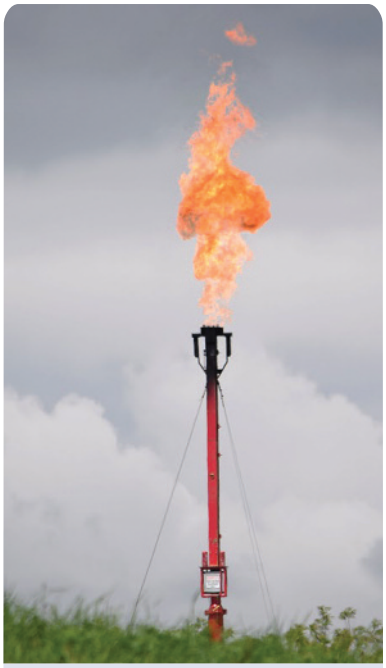


IMAGE: FracTracker Alliance

Flare on well pad, Belmont County, Ohio, May 2017

- *Hess* reports that the flaring intensity of its global operations decreased by 29 percent from 2014 to 2016. The company has set a target of reducing flaring intensity 50 percent by 2020 in its current assets, measured from a 2014 baseline. Flaring has been reduced most notably in North Dakota, where the company began investing in enhanced pipeline infrastructure and a gas processing plant prior to state regulations to reduce flaring.[125]

- *BHP* has a company-wide practice to minimize flaring of methane. Its latest well pad facility design incorporates capture of low-pressure gas that would otherwise be flared. The operations in its Permian Shale play successfully reduce production downtime and consequential flaring during cold winter weather through site design optimization consisting of optimizing chemical injection points, compression sizing and strategy, and the introduction of catalytic heaters and power redundancy to prevent gas lines from freezing and pressure drops. The process reduced 169,000 metric tons of GHG emissions during FY2017.[126]

- *Apache* seeks to lower emissions by reducing venting and flaring. The company is in the early stages of exploring and developing its Alpine High play, a "dark skies" area because of the nearby McDonald Observatory. Apache has worked with the observatory to develop "dark skies-friendly" protections for its facilities. The company is shutting-in its sizeable number of test wells before they reach their permitted flaring amounts.[127]

- *CONSOL Energy* states that it has a policy that the only acceptable reasons for flaring are for safety and low content of flammable gas. CONSOL requires that flares, when used, must have a 98 percent methane destruction efficiency, no visible emissions, and cannot be operated for periods exceeding a total of five minutes during any two consecutive hours.[128]

- *Chesapeake Energy* reports a policy to reduce the need to flare, but will flare in some instances due to operational or economic limitations. The company works to reduce flaring by adopting a number of described solutions in well planning, completions, and production. The company uses a Burner Management System (BMS) where it does flare, which it characterizes as a best practice in the industry. The BMS automates burner startup, normal operation, and shutdown, provides confidence the flare is operating effectively, enables remote monitoring of the flare, and shuts down the flare if a problem is detected.[129]

- *Range Resources*' new internal flaring policy requires staff to log and detail flare use to identify trends and improve operational practices.[130]

125. Hess Corporation, "2016 Sustainability Report", p. 43, http://www.hess.com/docs/default-source/gri/2016_hess_sustainability_report.pdf?sfvrsn=2. Also see Hess' response to CDP 2017 climate change survey, question CC2.2a, http://www.hess.com/docs/default-source/sustainability/hess-cdp-2017-final-06-29-17.pdf?sfvrsn=2.

126. BHP, "Case study: Responsibly managing hydraulic fracturing", Oct. 2017", p. 7, http://www.bhp.com/-/media/documents/environment/2017/171018_bhphydraulicfracturingcasestudy.pdf?la=en.

127. Apache Corporation, "2017 Sustainability Report", pp. 53, 63, and 103, http://www.apachecorp.com/Resources/Upload/file/2017_SustainabilityReport_10_24_17.pdf.

128. See CONSOL Energy's response to CDP 2016 climate change survey, questions OG3.4 and OG3.3, http://2015crr.consolenergy.com/wp-content/uploads/CDP-air.pdf.

129. Chesapeake Energy, "Preserving air quality", http://www.chk.com/responsibility/environment/air.

130. Range Resources, "Air quality best practices", http://rangeresources.com/corp-responsibility/environment-health-and-safety/air-quality-best-practices.

Methane Emissions Rate

Does the company report the percentage emissions rate for methane measured as methane emissions per unit of methane production on an annual basis, and/or the percentage emissions rate for methane emissions per MBoe (i.e., per thousands of barrels of crude oil equivalent, oil and gas) on an annual basis?

Intensity reporting is important as a means of comparing company emissions. Companies produce a combination of oil and gas in different proportions, on a spectrum from predominantly producing oil to predominantly producing gas. Many produce natural gas liquids, which can be more valuable than the methane. The amount of "associated gas" in shale oil plays can vary within and between plays.[131] Larger volumes of associated gas are more conducive to capture and sale than smaller ones.

The higher the emission percentage (i.e., the intensity), the higher the climate impacts of production. Measuring the emission rate annually enables a company and investors to track progress over time.

Scores

Sixteen (16) companies reported their methane emission rate.

Notable Practices

- Sixteen (16) companies report methane intensity rates including *Apache*, *BHP*, *BP*, *Chesapeake Energy*, *ConocoPhillips*, *CONSOL Energy*, *Devon Energy*, *EOG Resources*, *ExxonMobil*, *Hess*, *Newfield Resources*, *Noble Energy*, *Pioneer Natural Resources*, *Range Resources*, *Southwestern Energy*, and *Shell*.

Measurement and Estimation

With respect to measuring methane emissions, does the company describe how it measures and reports emissions, including when it uses and reports actual measurements and when it estimates emissions using engineering calculations or emission factors?

As noted above, EPA's Greenhouse Gas Reporting program publishes standards as to how emissions should be reported. These may not take into account the impact of company LDAR programs, other sources of variation in leak rates, or emissions from small facilities.[132] Even if companies are measuring actual emissions they generally must report to EPA using EPA-specified emission factors.

IMAGE: ConocoPhillips

Use of FLIR camera for LDAR program

131. For a map of the many gas-to-oil ratios in the Permian Delaware Wolfcamp play in Texas and New Mexico, see Figure 3 in V. Akuliniseva and R. Boros, "Wolfcamp Delaware: an assessment of recent activity with a GIS approach", https://www.rystadenergy.com/NewsEvents/PressReleases/wolfcamp-delaware-gis-approach.

132. Only large facilities (with emissions greater than 25,000 metric tons CO2e) are required to report greenhouse gas emissions to EPA, resulting in significant segments of the value chain not being required to report emissions. See U.S. Environmental Protection Agency, "Greenhouse gas reporting program and the U.S. inventory of greenhouse gas emissions and sinks", https://www.epa.gov/ghgreporting/greenhouse-gas-reporting-program-and-us-inventory-greenhouse-gas-emissions-and-sinks.

Regulatory reporting requirements aside, some companies may more aggressively measure actual emissions or attempt to quantify emissions from all operating facilities, i.e., create a more comprehensive inventory of emissions sources, to better inform their internal methane emission reduction strategies.

Companies reporting to CDP are asked to indicate which methods are used to estimate their company emission inventories. CDP categorizes these methods as direct detection and measurement, engineering calculations, and emission factors. Not all companies respond to CDP, not all respondents respond to this question, and not all respondents post CDP reports to their websites for easy public access.[133]

This question seeks to understand the full range of emissions reporting done by a company. Where reporting for CDP or CSR purposes, for example, differs from EPA reporting we would expect such differences to be noted in the company's website or CSR report.

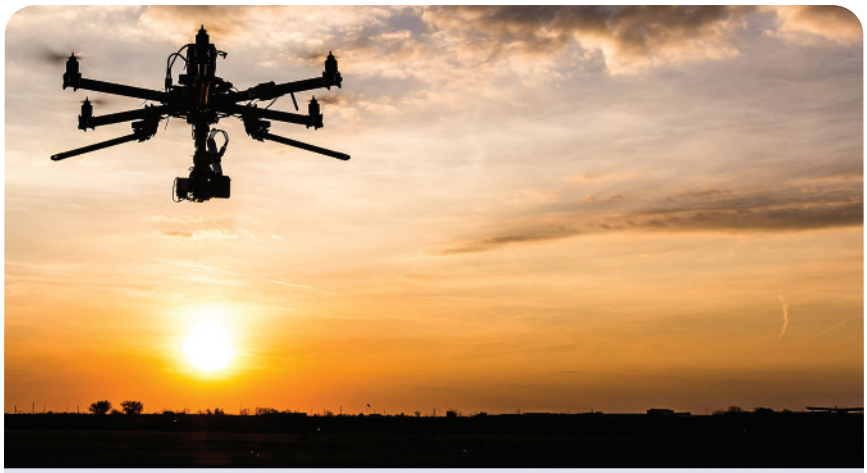


IMAGE: Environmental Defense Fund

Drone for aerial monitoring of emissions

Scores

Seventeen (17) companies reported on inventory compilation, estimates and measurements.

Notable Practices

- *CONSOL Energy* reports that its emission inventories have evolved from including select sources based on mandatory regulatory requirements to a more comprehensive emissions inventory including sources not previously characterized, such as fugitive leaks, tanks, blowdown events,[134] and pigging operations.[135] CONSOL states that the expanded inventory allows it to identify its largest emissions sources and opportunities for targeted reductions.[136]

- *ConocoPhillips* notes that EPA's emission factors for reporting are built on calculations rather than actual measurements. The calculations rely heavily on assumptions and extrapolations that do not allow for differences in facility design and construction. The company also notes that facilities located in the western part of the U.S. can have an emissions factor over 25 times greater than an identical unit based in the East. ConocoPhillips states that this led to higher estimates for its San Juan, New Mexico operations where, until it sold these assets in 2017, it was the largest producer. The San Juan Basin emissions had accounted for approximately two-thirds of the company's Lower 48 onshore emissions.[137]

133. *DTF 2017* does not award credit for CDP report disclosures not posted on a company's website.

134. A blowdown event refers to release of gas from a pipe or other vessel to the atmosphere in order to relieve pressure so that maintenance, testing, or other activities can take place. See M.J. Bradley and Associates, LLC, "Pipeline blowdown emissions and mitigation options", http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf. See also S.M. Richardson and G. Saville, "Blowdown of vessels and pipelines", 2016, http://www.ichemeoncampus.org/communities/subject_groups/safety%20and%20loss%20prevention/resources/hazards%20archive/~/media/Documents/Subject%20Groups/Safety_Loss_Prevention/Hazards%20Archive/S130%20-%20Major%20Hazards%20I/S130-15.pdf.

135. "Pigs" are devices used to maintain pipelines.

136. CONSOL Energy, "2016 Corporate Responsibility Report", p. 20, http://www.consolenergy.com/consolenergy/media/Pdf/2016_Consol_CRR_Interactive.pdf.

137. ConocoPhillips' sale of its San Juan Basin assets serves as a reminder of how much a company's reported methane emissions can be altered dramatically by asset transfers.

- *Shell* states that it reports emissions to government agencies in the U.S. and Canada according to their requirements, which specify the sources to be reported on and the emission factors to be used for emission estimates.[138] The company goes beyond these regulatory requirements in its annual sustainability report, including reporting a more comprehensive set of methane sources, mainly using EPA and API measurement-based emission factors but also drawing on actual measurements.[139]

- *Southwestern Energy*, like Shell, reports emissions to EPA according to the agency's requirements, but goes beyond those requirements in reporting emissions and its leak/loss rate in its corporate sustainability report. To do this, it uses a measurement device to quantify leaks from various sources (e.g., valves, flanges, connectors, unions, regulators, gauges, tank hatches, reciprocating compressors, pneumatic controllers, pneumatic pumps, and other "leaks").[140]

- *Pioneer Natural Resources* discusses the limitations of the EPA emissions inventory, stating that the datasets and models used to calculate emission factors are more than 20 years old, despite subsequent changes in technology and industry facility designs. The company states that reporting requirements capture most but not all of the emissions associated with Pioneer's equipment and activities. The company is working to better quantify other emissions sources to develop a more comprehensive emissions inventory and is analyzing its emissions to better understand them.[141]

- *Hess*, when reporting emission rates for its processing operations, describes how such rates can be influenced by changes in EPA's reporting rules. The emission rate for 2016 from its processing operations was 0.19 percent, up from 0.11 percent the prior year. In 2016, EPA required reporting of some new fugitive methane emission sources previously not reported, which were associated with the natural gas gathering and processing sector. Hess explains that these fugitive emissions led to the reported rise in its methane emission rate.[142]

High-Bleed Controllers

Does the company report the percentage or number of high-bleed controllers replaced with low-emission alternatives, or a program for their replacement?

High-bleed valves are a major source of methane emissions. Regulations can require use of low- or no-bleed valves for some types of facilities.[143] Regardless of regulatory requirements for new sources, companies can voluntarily replace high-bleed controllers at existing wells. Companies that have routinely installed such valves for many years will have already minimized emissions and will not need to retrofit. Other companies will have a sizeable inventory of high-bleed valves at existing wells whose replacement can be very cost-effective and environmentally beneficial.

138. Shell, "Shell onshore operating principles in action in North America: methane fact sheet", p. 4, http://www.shell.com/energy-and-innovation/natural-gas/tight-and-shale-gas/shells-principles-for-producing-tight-shale-oil-and-gas/_jcr_content/par/textimage.stream/1507135526769/abd11ad05683091c88be55320ecb6366cd46b3edc5561386352a7231376e0408/shell-methane-fact-sheet-3-october-2017.pdf.

139. Shell, "Sustainability Report 2016", https://reports.shell.com/sustainability-report/2016/.

140. Southwestern Energy, "Achieving our Commitments: Corporate Responsibility Report Appendix 2016-2017", p. 8, https://www.swncr.com/assets/files/appendix-2016-17.pdf.

141. Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air.

142. Hess, "2016 Sustainability Report", p. 45, http://www.hess.com/docs/default-source/pdfs/new-2016sr-07-25-17-compressed.pdf?sfvrsn=2.

143. For example, NSPS regulations adopted in 2012 by EPA for new and modified gas wells and compressors. See "Summary of requirements for processes and equipment at natural gas well sites", https://www.epa.gov/sites/production/files/2016-09/documents/20120417_natural_gas_summary_gas_well.pdf and "Summary of requirements for processes and equipment at natural gas processing plants", https://www.epa.gov/sites/production/files/2016-09/documents/20120417summaryprocessing_equipment.pdf.

Scores

Sixteen (16) companies reported on elimination of high-bleed controllers.

Notable Practices

- *Carrizo Oil & Gas*, *CONSOL Energy*, *Range Resources*, *Pioneer Natural Resources*, and *Southwestern Energy* report that they do not use any high-bleed valves in their operations.[144]
- *BHP* reports that it has replaced all high-bleed valves in all of its plays.[145]
- *Noble Energy* reports that it has replaced 99 percent of the high-bleed valves in all of its U.S. plays.[146]
- *Newfield Exploration's* new wells in Oklahoma's SCOOP play rely on non-pneumatic controls powered by solar energy instead of natural gas.[147]
- *ExxonMobil* has announced a voluntary three-year plan beginning in 2017 to phase out the approximately 1,250 high-bleed pneumatic devices in its U.S. operations.[148]
- *Shell* reports that it is consistently reducing high-bleed pneumatics, many of which it inherited as a result of mergers and acquisitions. It committed in 2017 to replacing the remaining high-bleed valves with low-emission alternatives within five years, except those needed for safety purposes.[149]

Emissions Reduction Compensation Incentives

Does the company disclose how it incentivizes greenhouse gas reductions at the board, management, and/or staff levels through compensation structures?

Money talks. Encouraging employees and management with incentives that reward success in reducing greenhouse gas emissions can be effective and should be considered by companies. This question therefore asks what financial incentives companies provide at all levels to reward such initiatives.[150] The question does not focus specifically on methane because tying incentives even to greenhouse gas emission reductions is a nascent practice.

144. Carrizo Oil & Gas, "Environment", http://www.carrizo.com/sustainability/environment; CONSOL Energy, "Air", http://www.consolenergy.com/responsibility/core-values/enviroment/air; Range Resources, "Air quality best practices", http://www.rangeresources.com/corp-responsibility/environment-health-and-safety/air-quality-best-practices; Pioneer Natural Resources, "Air", http://www.pxd.com/values/sustainability/air; Southwestern Energy, "Achieving our Commitments: Corporate Responsibility Report Appendix 2016-2017", p. 8, https://www.swncr.com/assets/files/appendix-2016-17.pdf.

145. BHP, "Case study: Responsibly managing hydraulic fracturing", Oct. 2017", p. 7, http://www.bhp.com/-/media/documents/environment/2017/171018_bhphydraulicfracturingcasestudy.pdf?la=en.

146. Noble Energy, "Response to Disclosing the Facts 2017", https://www.nblenergy.com/sites/default/files/Final%20-%202017%20Disclosing%20the%20Facts.pdf.

147. Newfield Exploration, "Air quality and climate change," http://www.newfield.com/corporate-responsibility/safety-environmental/air-quality-climate-change.

148. ExxonMobil, "XTO Energy methane emissions reduction program", http://corporate.exxonmobil.com/en/energy/natural-gas/environment-and-safety/xto-energy-methane-emissions-reduction-program.

149. Shell, "Shell onshore operating principles in action in North America: Methane fact sheet", p. 4, http://www.shell.com/energy-and-innovation/natural-gas/tight-and-shale-gas/shells-principles-for-producing-tight-shale-oil-and-gas/_jcr_content/par/textimage.stream/1507135526769/abd11ad05683091c88be55320ecb6366cd46b3edc5561386352a7231376e0408/shell-methane-fact-sheet-3-october-2017.pdf.

150. This inquiry is a variation on a question first asked in *DTF 2016* linking executive compensation to environmental health and safety indicators other than spills, injuries, and fatalities. In 2016, 22 of the 28 companies ranked included spills, injuries, and/or fatalities in their executive compensation calculations, as disclosed in corporate proxy statements. Only three—CONSOL Energy, BHP, and Shell—linked to other environmental health and safety factors. *DTF 2017* focuses specifically on links to greenhouse gases and extends beyond corporate executives. CDP asks a similar question.

Scores

Eight (8) companies reported on executive compensation linked to greenhouse gas reduction.

Notable Practices

- *BHP* includes health, environment, and community initiatives in determining its executive compensation. The company reported that in 2016 it exceeded its greenhouse gas reduction targets, established at the beginning of the year, for commodity segments.[151]
- *Shell* reports that sustainable development accounts for 20 percent of the company scorecard that determines annual bonuses for all employees, including Shell's Executive Committee. The Remuneration Committee of Shell's board is focusing the environmental component of sustainable development on greenhouse gas emissions, including refining, chemical plants, and flaring in the company's upstream operations. Within these assessments, the company specifically includes methane.[152]
- *Apache* incentivizes its business unit and facility managers to achieve various goals. Included in this is a process to track and improve energy efficiency while reducing greenhouse gas emissions per unit of production or emission intensity.[153]

151. BHP, "Annual report 2016", p. 131, http://www.bhp.com/-/media/bhp/documents/investors/annual-reports/2016/bhpbillitonannualreport2016_interactive.pdf.

152. Shell, "Sustainability Report 2016: Our executive scorecard", http://reports.shell.com/sustainability-report/2016/introduction/how-sustainability-works-at-shell/our-executive-scorecard.html.

153. Apache, "Supplemental disclosures", http://www.apachecorp.com/Resources/Upload/file/sustainability/APACHE-2016_Supplemental_Disclosures.pdf. (This document includes all the information Apache would include in a climate change report to CDP if it were to participate in CDP.

CONCLUSION

The first *Disclosing the Facts* report was issued in 2013 in response to immense public pressure on hydraulic fracturing companies to reduce environmental and community risks from this new and unconventional means of producing oil and gas. As a result of this pressure, and the risk it posed to companies' social license to operate, investors sought increased company disclosures to better understand these risks and how companies are managing them.

Company disclosures have improved substantially since the release of *DTF 2013*, with greater reporting across a greater range of factors—from how companies address water quality and quantity impacts to practices designed to reduce earthquakes, and a whole range of issues in between. We have seen reporting move from qualitative statements and assertions to much greater fact-based and quantitative reporting. During this time, company leaders in reporting have emerged, while overall, many more companies have adopted better reporting practices.

Through this process, investors and companies have learned much from one another; companies better understand why investors care about these issues and investors know more about the industry, why and how companies are addressing risk, and areas where more action is needed.

In the meantime, an existential issue has emerged—climate change. Investors have begun to understand the enormity of climate risk to their portfolios and to the companies in which they invest, including, in particular, oil and gas companies. In addition to pressure from the public and regulators, the financial market has begun to demand disclosures from companies on climate risk, and is quickly moving to price climate risk into company assessments and valuations. From the Financial Stability Board, to Moody's bond ratings, to the largest investment managers—in quickly decarbonizing global energy markets, company responsiveness and action to reduce greenhouse gas emissions is key, as is the need for clear disclosures to investors.

With this knowledge, methane emissions from the oil and gas industry has emerged as both a call to immediate action and an opportunity for companies to achieve substantial greenhouse gas emission reductions in their operations, preserve the potential for reduced climate impacts of natural gas, and increase efficiencies in oil and gas production operations. Acknowledging these risks and opportunities, the oil industry itself is calling for a range of voluntary actions from companies.

Recognizing the importance of the methane issue, and as reflection of changing energy realities, DTF 2017 has focused on this newest challenge. To stay in the game in a decarbonizing global economy, the oil and gas industry must be quick to demonstrate responsiveness and demonstrable success in reducing greenhouse gas emissions, especially with regard to methane and its high global warming impact. We hope that the newly evolved questions in this report will give industry a clear disclosure framework to help it meet this latest challenge.

APPENDIX A: SCORECARD QUESTIONS*

* Asterisks denote questions previously asked in *DTF 2016.*

1. Does the company describe its leak detection and repair program, including the facilities and assets covered by the program?*

2. Does the company describe the specific methodologies used (e.g., infrared camera, audio visual olfactory, continuous monitoring, stationary methane detectors) to identify methane leaks in its operations?*

3. For each of the specific methods described, does the company describe how frequently it uses each and what proportion/percentage of each facility and/or asset is covered?*

4. Does the company describe its leak repair procedure(s), principally the routine time period between leak detection and repair?

5. Does the company describe its engineering and maintenance practices to prevent or minimize leaks?

6. Does the company describe the leak detection training it provides its operational/production staff, contractors who routinely visit well sites and/or are hired to conduct leak detection and repair, and staff trained specifically to conduct LDAR?

7. Does the company disclose an active, quantitative methane emissions reduction target, with timeline, and progress toward achieving this target?*

8. Does the company describe its company-wide methane venting practices?

9. Does the company describe its company-wide methane flaring practices, including success in reducing flaring?

10. Does the company report the percentage emissions rate for methane measured as methane emissions per methane production on an annual basis, and/or the percentage emissions rate for methane emissions per MBoe (i.e., per thousands of barrels of crude oil equivalent, oil and gas) on an annual basis?*

11. With respect to measuring methane emissions, does the company describe how it measures and reports emissions, including when it uses and reports actual measurements and when it estimates emissions using engineering calculations or emission factors?

12. Does the company report the percentage or number of high-bleed controllers replaced with low-emission alternatives, or a program for their replacement?*

13. Does the company disclose how it incentivizes greenhouse gas reductions at the board, management, and/or staff level through compensation structures?

APPENDIX B: METHODOLOGY

Scorecard Goals

Disclosing the Facts 2017 has three goals: (1) assess the overall state of industry disclosure; (2) identify those issues about which most disclosures are made; and (3) distinguish industry leaders from laggards with regard to disclosure.

Company Selection

The scorecard reports on 28 publicly traded companies producing shale gas and oil in the United States and Canada.

Geographic Coverage

The scorecard addresses onshore operations in the United States and Canada.

Chronological Coverage

The scorecard addresses reporting on specific, identified metrics from July 1, 2017 to October 20, 2017.

Indicator Selection

Indicators are both qualitative and quantitative. The goal was to select indicators that would enable clear "yes/no" answers, with minimal interpretation required by participating companies. This edition of the scorecard contains 13 indicators, representing both new indicators about methane management and methane-related indicators from prior editions of *Disclosing the Facts*.

Company Scoring

Each company was scored based solely on documents and information available through its public website, including SEC proxy and annual report filings, climate change reports submitted to CDP and posted directly on the company website, and sustainability/social responsibility reports. Companies were scored independently by two or more project staff. Companies received a copy of the questions on which they were scored, the corporate disclosures found pertinent to the questions, and their draft scores. Companies were given an opportunity to provide feedback on the accuracy of the scorecard information compiled and to update their public disclosures. Final scoring was based on staff reviews of corporate disclosures published on company websites by October 20, 2017.

APPENDIX C: GLOSSARY

Audio-Visual-Olfactory (AVO) Inspection
AVO inspection involves company staff or contractors detecting leaks by listening, looking, or sniffing for leaks during their routine onsite visits.

Blowdown Event
A blowdown event refers to release of gas from a pipe or other vessel to the atmosphere in order to relieve pressure so that maintenance, testing, or other activities can take place.

Flaring
Flaring is the burning of methane not captured for sale or for onsite generation of energy.

Flashing
Flashing describes volatile components in a liquid suddenly emerging as a gas, for example when temperature is raised or pressure is reduced in a containment vessel.

Fugitive Emissions
Fugitive emissions are unintentional infrastructure leaks, such as from pieces of equipment and connections between them. They can also result from system malfunctions. Fugitive emissions are different from vented emissions, defined below.

Liquid Load-out
Liquid load-out is the transfer of liquids from tanks to trucks. Simple connections will vent fumes to the atmosphere while more advanced loading systems allow for capture of these emissions.

Liquids Unloading
Liquids unloading is the removal of liquid that has accumulated in tubing and prevents natural gas from flowing up through a producing gas well.

Optical Gas Imaging (OGI) Camera
An OGI camera detects emissions that are not otherwise visible. OGI cameras sometimes are labeled FLIR cameras, for the Forward-Looking Infrared (Radar) they use.

Plunger Lift
A plunger lift is a device for removing liquids from productive natural gas wells. (See liquids unloading above.)

Pneumatic Controller
A pneumatic controller regulates process conditions such as temperature. When it is operated by natural gas, gas is released to the atmosphere during the device's operation. "Low-bleed" pneumatic controllers release fewer emissions than "high-bleed" pneumatic controllers. Pneumatic controllers powered by compressed air do not release natural gas to the atmosphere.

Tank Battery
A tank battery is a group of tanks that are connected to receive crude oil production from a well or a producing lease. A tank battery is also called a battery. In the tank battery, the oil volume is measured and tested before pumping the oil into the pipeline system.

Thief Hatch
Thief hatches are openings at tops of storage tanks that allow measurements to be taken.

Vapor Recovery Unit
A vapor recovery unit is a device that captures for sale or other purposes vapors that otherwise would be vented or flared.

Venting
Venting is the direct release of gas to the atmosphere from intentional routine operations such as liquids unloading and operations of pneumatic controllers powered by natural gas. They are distinguished from unintended fugitive emissions, defined above.

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