Waste Not

Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry

Clean Air Task Force | Natural Resources Defense Council | Sierra Club

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Waste Not:
Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry

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EXECUTIVE SUMMARY

Oil well and flare in North Park, Colorado

THE CASE FOR TAKING ACTION on climate change has never been clearer: as the third National Climate Assessment states, the U.S. is already experiencing the effects of climate change, from increasing heat across the country to more extreme weather events totaling billions of dollars in damage. Given these impacts, and much worse to come, the cost of inaction to our health, environment, and economy is far too great, especially when effective and low-cost means for reducing climate-warming pollution are available now. In this report, we show how the U.S. Environmental Protection Agency (EPA) can fulfill the agency's duty under the Clean Air Act to cut by half dangerous, wasteful methane pollution from the largest industrial source—the oil and gas industry—in just a few years, using common sense standards based on available, low-cost control measures for a targeted set of pollution sources.

Reducing methane emissions from the oil and gas sector would build on the Obama Administration's actions to date to cut climate pollution. Most recently, in a landmark U.S.-China agreement, the President announced a U.S. target of reducing greenhouse gas emissions 26 to 28 percent below 2005 levels by 2025. This pledge follows on the previous U.S. commitment to reduce emissions by 17 percent below 2005 levels by 2020. In June of 2014, EPA took its most significant climate protection step to date by proposing the Clean Power Plan to tackle the predominant climate pollutant, carbon dioxide (CO_2), from its largest U.S. source, existing power plants. The Administration has also set standards in motion to reduce carbon pollution and improve fuel efficiency from new motor vehicles, addressing the second-largest U.S. source of CO_2.

EPA must now curb methane pollution from the oil and gas sector, the second largest industrial contributor to heat-trapping emissions. Methane is the main component of natural gas. It is a powerful climate-changing pollutant that, according to the most recent international climate science assessment report, packs 36 times the heat-trapping punch of carbon dioxide, pound-for-pound, in the century after it is released. Over a shorter period of 20 years, methane is 87 times more powerful than carbon dioxide.

The U.S. oil and gas industry leaks and intentionally releases almost eight million metric tons of methane a year, according to EPA's most recent *Inventory of U.S. Greenhouse Gas Emissions and Sinks*—enough to heat 6.5 million U.S. homes. However, the EPA *Inventory* is very likely an underestimate. Independent research demonstrates that actual methane emissions from the oil and gas sector could be twice as high as shown in current government inventories, and may be even higher. Despite the EPA *Inventory*'s likely underestimate of methane emissions, this report's calculations are based on the EPA *Inventory* to provide conservative estimates. As we describe below, methane is not the only pollutant in natural gas, and the measures we recommend in this report would reduce emissions of those other pollutants, too, benefiting air quality.

EPA took an important step forward on methane in 2012, issuing standards for volatile organic compounds (VOCs) that reduce some methane pollution from the oil and natural gas industry. Most notably, these rules limit completion emissions—the burst of pollution that can occur in the first few days after a well is hydraulically fractured. Instead of allowing methane and other pollutants to escape to the atmosphere, the standard requires operators of gas wells to capture the gas and sell or use it—a procedure known as a "reduced emission completion." EPA recently reported that emissions from natural gas well "completions" have decreased 73 percent since 2011. The standard, however, covers only fractured gas wells and not fractured oil wells, which often produce methane pollution during completion. The standard also addresses a few other types of *new* equipment, such as new tanks and compressors. However, it does not reduce methane from equipment that was already in use when the rule went into effect, such as existing compressors, and/or equipment that emits relatively low levels of VOCs, such as facilities in major cities that receive natural gas. Yet this equipment is responsible for the vast majority of the sector's methane pollution.

Recognizing the importance of further reducing methane pollution, in March 2014, the Obama Administration released a "Strategy to Reduce Methane Emissions." The plan specifically directs EPA to assess methane emissions from the oil and gas sector and determine by fall 2014 whether to

KEY FINDINGS

The oil and gas industry is the nation's largest industrial source of methane, a much more potent climate-warming pollutant than carbon dioxide pound-for-pound, and the oil and gas sector is the second largest industrial contributor to overall climate pollution. Moreover, there is compelling evidence that the industry is releasing a lot more methane than is currently accounted for in government inventories.

EPA could reduce the sector's methane pollution by half in a just few years by issuing nationwide methane standards that require common sense, low-cost pollution controls for the sector's top emitting sources:

- Regular leak detection and repair programs can reduce methane pollution by an estimated 1,700,000 to 1,800,000 metric tons per year. EPA standards should require oil and natural gas companies to control leaks from all equipment at wellpads, gas processing plants, compressor stations, and large aboveground distribution facilities by regularly carrying out these inspections.
- Cleaning up older equipment—compressors and gas-driven pneumatic equipment—with proven technologies and practices can reduce methane pollution by an estimated 1,200,000 to 1,350,000 metric tons per year. Current EPA standards require these technologies and practices for some new compressors and gas-driven pneumatic equipment in select segments of the industry, while states like Colorado extend some requirements to existing sources. EPA should set additional standards that require the same practices for all such equipment—both new and existing—throughout the industry.
- Capturing natural gas that would otherwise be released from oil and gas wells can reduce methane pollution by an estimated 260,000 to 500,000 metric tons per year. EPA standards should require well operators to capture this gas and sell it or use it on-site, instead of releasing it or flaring it.

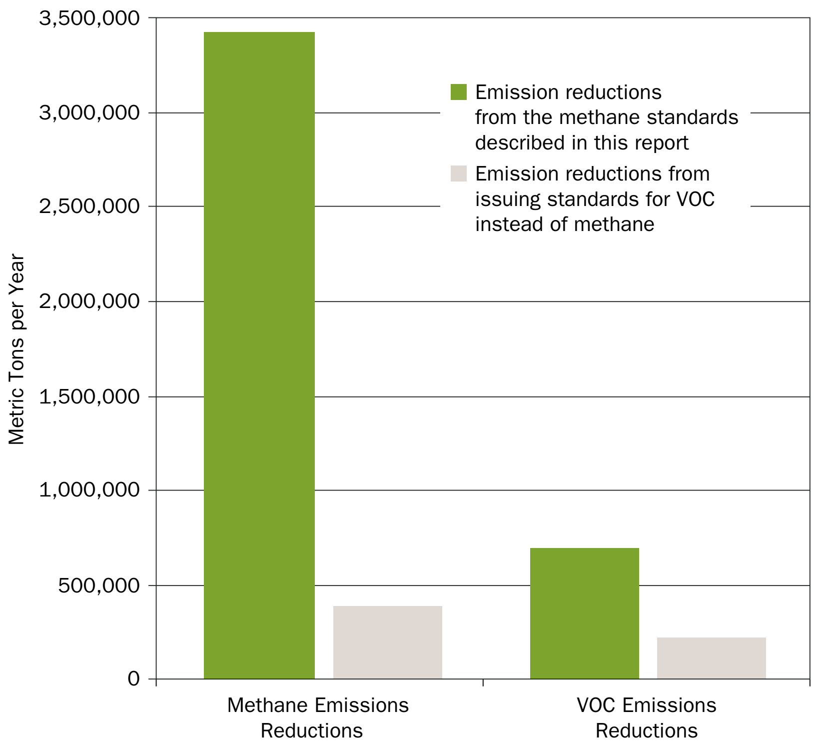
The methane abatement potentials shown above are conservative estimates based on government inventories. They don't account for the research indicating that actual emissions could be twice the inventory estimates, or higher. The problem and the upsides of controlling it—are likely much greater.

The standards we recommend in this report would also significantly reduce emissions of other air pollutants, specifically smog-forming volatile organic compounds and toxic pollutants like benzene that cause cancer and are associated with a host of other health problems.

The cost of the recommended standards would be low—less than one percent of the industry's sales revenue.

EPA should issue specific methane standards for the sources described above, including standards for new and existing equipment and practices. Methane standards would cut up to ten times more methane and four times more smog-forming pollutants compared to other policy approaches available to EPA, because more sources would be reached.

FIGURE ES-1
Regulating VOC vs. Regulating Methane



Source: CATF analysis.

set Clean Air Act standards to curb methane pollution from the oil and gas industry. If the agency decides to issue standards, the plan calls for them to be completed by the end of 2016. Moving forward under the Methane Strategy, EPA in April 2014 solicited input from the public and independent experts on technical white papers covering the largest sources of methane leakage across the industry, solutions to reduce emissions, and costs of reductions.

In spring 2014, as part of EPA's public comment process under the Methane Strategy, our organizations submitted detailed technical comments in response to the agency's white papers. The present report summarizes and further describes the significant, low-cost opportunities to reduce methane from the oil and gas sector that EPA's white papers, and our comments, describe. We set forth how direct standards for methane can cut total methane emissions from the sector by half—reducing annual methane emissions at least 3.2 million to 3.7 million metric tons—in just a few years. These benefits are well beyond the reductions achievable through other approaches EPA is considering.

A key choice before EPA is whether to set standards to reduce pollution from the oil and gas industry, and if it does so, whether to set standards for emissions of methane, or for smog-forming VOC pollution that would reduce methane to some degree as a "co-benefit." Our report demonstrates that the direct approach of setting methane standards would be far more effective in reducing methane pollution than setting VOC standards, and would also achieve significant VOC reductions. When setting standards for methane, EPA is required to address existing sources of pollutants, which results in greater reach. In addition, methane standards would encompass equipment that puts out high amounts of methane, but relatively low amounts of VOCs, such as sources in the transmission segment. In sum, new methane standards would reach the sector's climate pollution sources left unaddressed by EPA's 2012 standards. As we show in Figure ES-1, methane standards would cut methane pollution from the oil and gas sector by up to 10 times as much as the alternative pathway. And though it may seem surprising, methane emission standards would reduce smog-forming VOC pollution three to four times more than VOC emission standards.

EPA can achieve these reductions by setting simple, technology-based emission standards under sections 111(b) and (d) of the Clean Air Act for a few types of new and existing equipment and operations across the sector. This action would have the same climate benefits over a 100-year timeframe as cutting more than 130 million metric tons (MMT) per year of carbon dioxide emissions. Over a 20-year timeframe, this would be equivalent to cutting more than 320 MMT per year of carbon dioxide, because methane is even more potent in the near-term.

Moreover, the actual tonnage of methane reductions achieved by these standards is very likely greater than what we calculate. As we note above, current emissions are likely to be higher than currently estimated by EPA, possibly significantly so. Strong evidence suggests that unusual but very large emissions resulting from improper conditions at oil and gas sites are important contributors to the methane that is observed in the air but not accounted for in the inventories. These large, unusual sources are referred to as "super-emitters." The measures we recommend target these sources. Most importantly, expanding leak detection and repair (LDAR) programs to cover the many facilities that are not inspected under current rules, as this report recommends, will identify and fix super-emitters. Thus, standards based on these measures could achieve emissions reductions that are twice as large as we estimate in this report, or perhaps even larger.

The measures highlighted in our core analysis are commercially available and in use, though far from universally. They have been demonstrated in the field to reduce emissions. In addition, the net cost of these measures is very low because they keep gas in the system instead of wasting it. Some of the measures pay for themselves in time because of this reduced waste. The overall abatement cost for all the technologies combined is just $8 to $18 per metric ton of carbon dioxide equivalent. To put these costs in perspective, the annual cost of implementing the measures is only one and a half percent of the annual revenue the industry receives from selling gas. Finally, the benefits to our climate and health far outweigh the costs of control to industry.

Plugging the Leaks: Addressing the Industry's Largest Sources of Methane Pollution

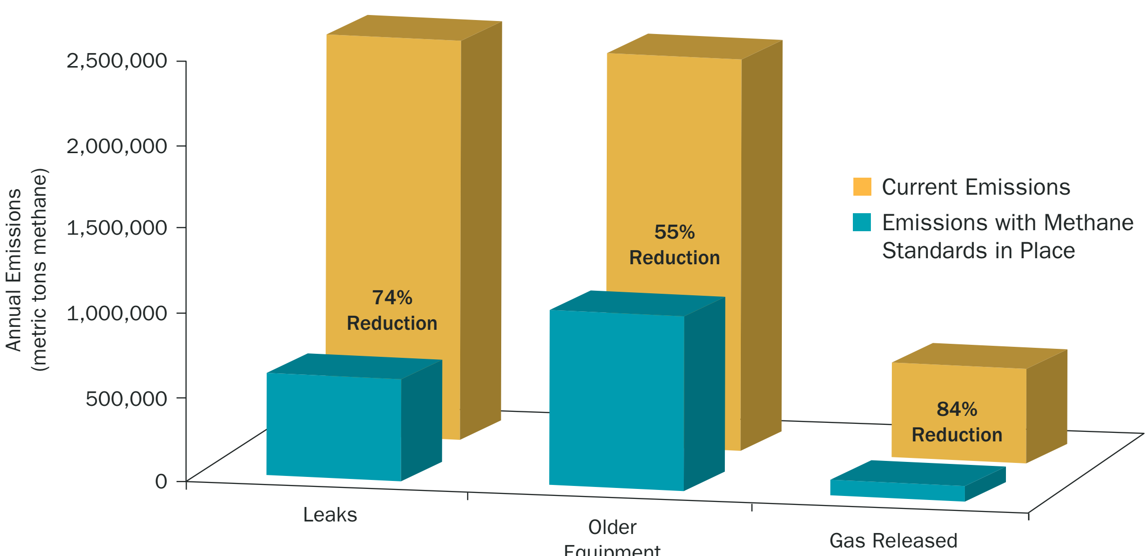
Methane is emitted from dozens of types of equipment and processes throughout the oil and gas sector, such as wells, completion operations, storage tanks, compressors, and valves. This report focuses on the sources that EPA examined in its white papers, which are the largest sources of methane pollution in the sector. These emissions can be cut dramatically in just a few years:

Completion equipment is used following hydraulic fracturing of natural gas wells in Washington County, Pennsylvania.

- ***Leaks from valves, connectors, and other equipment.*** These leaks can be curbed by requiring monthly or quarterly surveys to find and fix leaks at facilities throughout the sector, from well pads all the way to large aboveground distribution facilities in cities.
- ***Older equipment.*** Methane pollution from existing compressors and automatic pneumatic valve controllers can be cut dramatically by using up-to-date technology and maintenance practices to reduce emissions, consistent with standards EPA set in 2012 for certain types of new

FIGURE ES-2

Significant Methane Reductions are Possible at Sources Identified in this Report



Source: EPA U.S. Greenhouse Inventory/CATF analysis.

equipment, and with recent regulations in Colorado that apply to both new and old equipment.

- ***Intentional release of gas from oil and gas wells.*** Many oil wells produce and then vent large quantities of natural gas. These emissions can be curbed by requiring oil producers to capture or control gas otherwise emitted from oil wells after hydraulic fracturing, as well as during oil production, consistent with standards EPA put in place for hydraulically fractured gas wells. A similar approach can control venting from gas wells during liquids unloading, when water is removed from the well.

As we show in Figure ES-2 (p. 5), methane emissions from these sources are very large and can be addressed through standards that directly regulate methane emissions from a targeted set of new and existing equipment and operations, under the Clean Air Act authorities described above. Indeed, the methane mitigation measures we describe here would reduce methane pollution from oil and natural gas operations by at least 3.2 to 3.7 million metric tons per year, or 42 percent to 48 percent of the sector's estimated total methane emissions.

Other regulatory approaches are far less effective:

- A focus only on *new* sources to the exclusion of existing, unmodified sources would attain just a small portion of the achievable methane reductions because existing sources currently account for the vast majority of emissions and will continue to do so for years into the future if left unaddressed. According to one analysis, in 2018 nearly 90 percent of methane emissions from the oil and gas sector will come from facilities in operation since at least 2011. Pollution from these sources is not addressed by EPA's 2012 standards for new equipment, and they will probably continue to emit excessively for many more years absent methane standards for existing equipment.
- A focus on *another air pollutant* (such as VOCs) would also attain only a small portion of the achievable methane reductions, in this case because VOC regulations under the Clean Air Act provisions identified in the Methane Strategy would (a) likely not apply to any sources, new or existing, downstream of natural gas processing plants, where the VOC content of the gas stream is relatively low, and (b) potentially apply to existing sources only in areas with substantial ozone smog problems.

Large methane emission reductions are achievable at low cost using available technologies. Furthermore, in designing effective methane standards, EPA can look to model standards from leading states such as Colorado and Wyoming. EPA can also draw on elements of other existing federal standards that incorporate emission control measures like those that we propose here, such as EPA's 2012 VOC standards for the oil and gas industry.

Improving Air Quality by Reducing Methane

Methane is not the only air pollutant from oil and gas operations. Smog-forming VOCs and toxic air pollutants linked to cancer, respiratory and neurological damage also are released throughout the entire oil and gas supply chain. In addition to reducing dangerous heat-trapping pollution, the control measures we describe will reduce smog-forming pollutants and toxics by up to 22 percent and 14 percent, respectively.

In recent years, VOC emissions from oil and gas production have caused severe high-ozone episodes in several areas in the Western U.S., such as oil and gas producing areas in Wyoming and Utah. Research also has reported that in communities near oil and gas sites, toxic air pollutant levels are elevated enough to affect human health. Reductions in VOCs and hazardous air pollutants are critical in regions where oil and gas activities create smog levels that fail to meet health standards and in front-line communities burdened with toxic pollution.

Because they address a larger set of air pollution sources, methane standards based on the control measures we recommend will clean up the air more than the standards EPA issued in 2012 or any potential new standards aimed at VOC pollution. As we show in the figure, while the 2012 standards cut VOCs by an estimated 170,000 to 260,000 metric tons per year, new methane standards would cut VOC emissions by an additional estimated 570,000 to 830,000 metric tons per year or more. And these new methane standards would reduce VOC emissions three to four times more than potential new VOC standards. Reductions in toxic pollutant emissions from the recommended methane measures also are significant, but in addition to standards for methane, stringent standards for toxic pollutants are also needed to ensure compliance with the Clean Air Act and to protect public health.

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Oil well, tanks, and flare near Williston, North Dakota.

CHAPTER 1

INTRODUCTION

With the widespread adoption of hydraulic fracturing and other unconventional techniques to produce natural gas and other hydrocarbons, the U.S. oil and natural gas industry has grown substantially in recent years. Crude oil production in the U.S. grew almost 50 percent from 2008 to 2013, while marketed domestic production of natural gas has increased 35 percent since 2005, according to the U.S. Energy Information Administration. This oil and gas development boom has heightened concerns about air pollution from the entire oil and gas supply chain—from production of oil and gas, to gas processing, transmission and distribution.

Among the most pressing air pollution issues is the sector's contribution to climate change pollution. The oil and natural gas sector is the largest U.S. industrial emitter of methane, the primary constituent of natural gas and the second most important climate pollutant after carbon dioxide. Methane is a powerful climate-changing pollutant that warms the climate 36 times more than carbon dioxide, pound-for-pound, in the century after it is released. Over a shorter period of 20 years, methane is 87 times more powerful than carbon dioxide.[1] The oil and gas industry leaked and intentionally released 7.7 million metric tons of methane in 2012, according to EPA's most recent *Inventory of U.S. Greenhouse Gas Emissions and Sinks*.* This pollution will have the same climate impact over the next twenty years as half the gasoline burned in the U.S. in 2012.[2] As we discuss below, a wealth of recent measurements by independent researchers show that this figure is very likely to be an underestimate of actual methane emissions from oil and

* We use metric tons throughout this report, which we often shorten to "tons."

Natural gas drilling rig with horizontal drilling in Washington County, Pennsylvania.

gas: emissions certainly could be twice as high, and may be even higher.

Emissions from wellpads, compressors, processing plants, and other oil and gas industry facilities and processes include other air pollutants beyond methane. Raw natural gas (*i.e.*, gas as it is produced from underground formations, before significant processing is done) also usually contains significant fractions of volatile organic compounds (VOCs) and toxic hazardous air pollutants (HAPs), though it varies in composition from source to source.[3] VOCs are hydrocarbons that react with other pollutants in the presence of sunlight to form ground level ozone,* also known as smog, which causes a range of respiratory impacts. The HAPs in raw gas include hexane, benzene, and other aromatic chemicals; poisonous gases like hydrogen sulfide can also be present. These pollutants are also emitted from crude oil production operations. Health impacts associated with HAPs include cancer, respiratory and neurological impacts, and birth defects.[4]

These technologies would reduce emissions of methane from the entire oil and gas sector by approximately 42 to 48 percent.

While natural gas processing plants separate much of the VOCs and toxics from raw natural gas, some of those pollutants remain in the gas after processing.[5] As such, emissions of gas from facilities further downstream in the natural gas supply chain, like transmission compressor stations and local distribution equipment, do include VOCs and toxics. Though this report focuses on methane emissions, it is important to remember that reducing methane emissions throughout the oil and gas sector will also aid in reducing these other pollutants.[6]

Over the past few years research has demonstrated that air pollution from oil and gas activities is significantly degrading air quality in and downwind of several oil and gas producing regions. In some of these areas, air has become so unhealthy as a result of oil and gas activities that it violates national air quality standards. Episodes where the concentration of ozone greatly exceeds the standards set by EPA to protect public health have occurred multiple times in recent years in the Uinta and Upper Green River basins in Utah and Wyoming, respectively.[7] These areas are experiencing intense oil and gas activity, and it is well understood that emissions of VOCs from oil and gas operations are causing these high ozone episodes.[8] Recent work also indicates that emissions from oil and gas operations are resulting in concentrations of toxic HAPs that could harm the health of people living in and near oil and gas production areas.[9]

Oil and gas methane emissions are also, literally, a waste of energy. The estimated 7.7 million tons of methane that oil and gas sources emit, according to EPA, amounts to 470 billion cubic feet of natural gas, enough to heat 6.5 million homes.[10] Flaring of gas, primarily at wells, wastes at least another 200 billion cubic feet of gas.**

In this report we describe several proven technologies, all the subjects of a series of white papers on methane emissions from the oil and gas sector issued by EPA in April 2014, that can be rapidly and affordably deployed to reduce air emissions from the sector. These technologies, if applied to current emissions, would reduce emissions of methane from the entire oil and gas sector by about half: 3.2 to 3.7 million metric tons of methane, or 42 to 48 percent of EPA's most recent estimate of

* Methane also reacts with other pollutants to form ozone, but ozone formation from methane is much slower than from VOC, so methane produces ozone on a global scale, rather than locally. For this reason methane is not regulated as VOC.

** Flaring is a major source of pollution, and although it is not a focus of this report, it is discussed in Chapter 3 (see Box 7). The data on the magnitude of gas flaring in the U.S. is from the Energy Information Administration (see *http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_vgv_mmcf_a.htm*).

emissions from the entire sector, 7.7 million metric tons in 2012. This would have the same benefit for the climate over the twenty years after emissions are reduced as shutting down 70 to 80 coal-fired power plants.[11] At the same time, these measures would reduce smog-forming VOC pollution by over half a million tons per year, and would reduce emissions of toxic air pollutants by tens of thousands of tons per year. And, as we note above, actual emissions from oil and gas are certainly higher than EPA estimates, and the actual *benefits* of these rules could be twice as large as we state above, and may be even larger than that.

Because these are proven, straightforward technologies that keep gas in the system instead of wasting it, the overall net cost of this set of measures is very low. The total average abatement cost for all the technologies combined is $8 to $18 per metric ton of carbon dioxide equivalent, among the most affordable of available greenhouse gas reduction opportunities. In addition to the set of measures being low cost as a whole, each individual measure is also affordable on average, although costs may be lower or higher for different operators and locations (as they are for other pollution abatement measures) depending on particular operational conditions. Indeed, a number of these measures more than pay for themselves—the value of the gas that the new technology saves is larger than the cost of the technology.

Requiring these measures nationwide at new and existing oil and gas facilities would reduce climate damage from methane, improve air quality, and result in less waste of energy resources, all at a low cost. EPA should build upon its work so far to reduce greenhouse gas emissions from other sources, such as vehicles and power plants,[12] as well as its 2012 regulations addressing VOC emissions from the oil and gas sector (see Box 2 in Chapter 2), by issuing new regulations to rapidly reduce wasteful and harmful methane emissions from oil and gas operations. This report offers a common-sense approach to significantly reduce oil and gas air pollution to help clean up the air and move toward the national greenhouse gas emissions goals that are essential to stabilizing our climate.

Emissions Estimates and Data Sources

A number of recent peer-reviewed studies show that actual methane emissions from the oil and gas industry are significantly higher than EPA estimates in the U.S. GHG Inventory.

"BOTTOM-UP" VERSUS "TOP-DOWN" STUDIES

Studies of methane from the oil and gas sector take one of two general forms:

- "Top-down" studies measure pollutants in the atmosphere and ask what those measurements reveal about the sources of air pollution. Specifically, these studies measure methane and other constituents of natural gas in the air in, and downwind of, areas where oil and gas activity is occurring, and then calculate the fraction of this methane (or other pollutants) that is attributable to oil and gas sector activity.
- "Bottom-up" studies, in contrast, start with measurements of air pollution directly from a sample of sources in the field and extrapolate the amount of pollution that the sector produces, based on average values from those measurements.

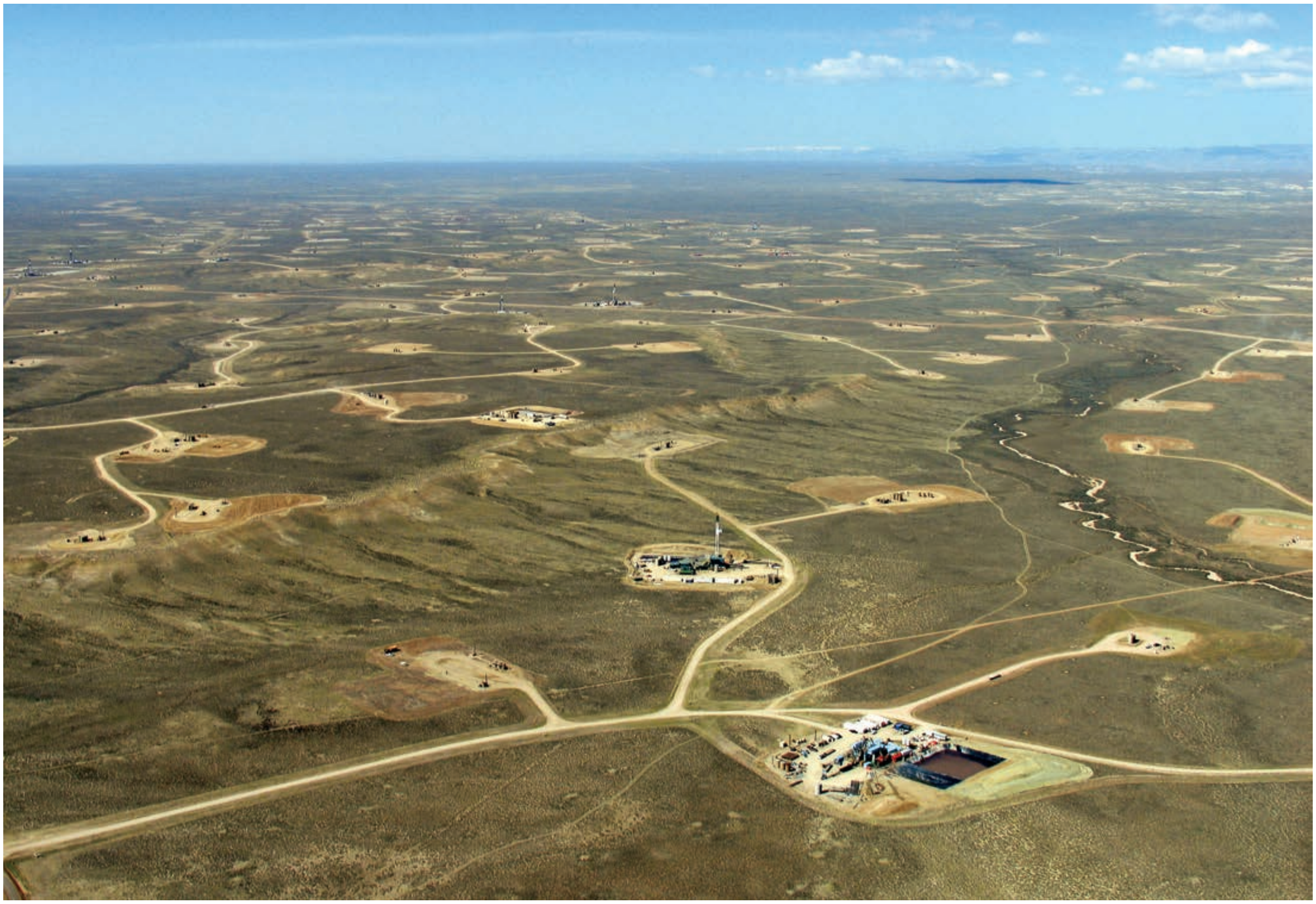
Bottom-up studies are essential to identifying specific sources of emissions that can be reduced with control measures. However, the emission averages on which they are built are often limited in their representativeness, because they generally use limited samples which may not reflect the diversity of sources in the oil and gas sector (and may not reflect uncommon but very high-emitting "super-emitters"—see "Finding and Fixing Leaks section of Chapter 3), and are performed in cooperation with the owners of oil and gas facilities. Thus estimates of total emissions based on a bottom-up approach, like the U.S. GHG Inventory, may not represent typical conditions at a wide range of operations, and accordingly may not provide an accurate estimate of the overall magnitude of emissions.

Top-down studies provide a critical independent measure of the total volume of emissions in an area, capturing emissions from all sources. These studies thus are an important check on bottom-up estimates, though emission attribution to sources such as oil and gas can be imprecise, and only limited information is available on the magnitude of emissions from specific sources within the industry.

RECENT TOP-DOWN STUDIES

In the last several years, independent researchers have published a number of peer-reviewed estimates

* This is calculated using a 100-year GWP for methane of 36, as recommended by IPCC's AR5.



Natural gas well pads, pipelines, and other associated infrastructure in the Upper Green River Basin in Wyoming. Once home to pristine, clean air and very little industrial activity, emissions from oil and gas production in this area now lead to unhealthy levels of smog.

of methane emissions from the oil and gas sector utilizing top-down techniques. These studies provide compelling evidence that the aggregate methane emission estimates based on "bottom up" methodologies, including the U.S. GHG Inventory, underestimate methane emissions by a significant margin, including from the oil and gas sector.

Some of the most important top-down studies include:

NATIONWIDE EMISSIONS

An early top-down study, Xiao *et al.* (2008), estimates that nationwide emissions of methane from fossil fuel sources in 2004 were 50 to 100 percent higher than bottom-up inventories estimate.[13] Miller *et al.* (2013), uses atmospheric measurements of methane in 2007 and 2008 to estimate that methane emissions from all U.S. sources were 50 percent higher than estimated for that year by the 2012 U.S. GHG Inventory. The study shows that oil and gas emissions constitute a significant portion of the observed emissions not accounted for in EPA's Inventory.[14]

REGIONAL/BASINWIDE EMISSIONS

Karion *et al.* (2013) reports that 6 to 12 percent of the methane produced by oil and gas fields in Utah's Uinta Basin in early 2013 was released into the air.[15] Petron *et al.* (2014) reports that the methane emission rate from oil and gas operations in the heart of the Denver-Julesberg Basin was 4.1 ± 1.5 percent in mid-2012. These "leak rates" are *far* higher than the less than 1 percent leakage rate for oil and gas production and gas processing that would be expected from the nationwide emissions estimates in the U.S. GHG Inventory.[16] To date, measurements of leak rate are only available from a small number of basins, and variation is expected between basins. It is clear from studies at broader scales[17] and industry reports[18] that the Utah leak rate is well above the national average. Nonetheless these results are alarming.

SYNTHESIS STUDIES

Brandt *et al.* (2014) systematically reviews eleven top-down and a number of bottom-up studies, including the studies discussed above (with the

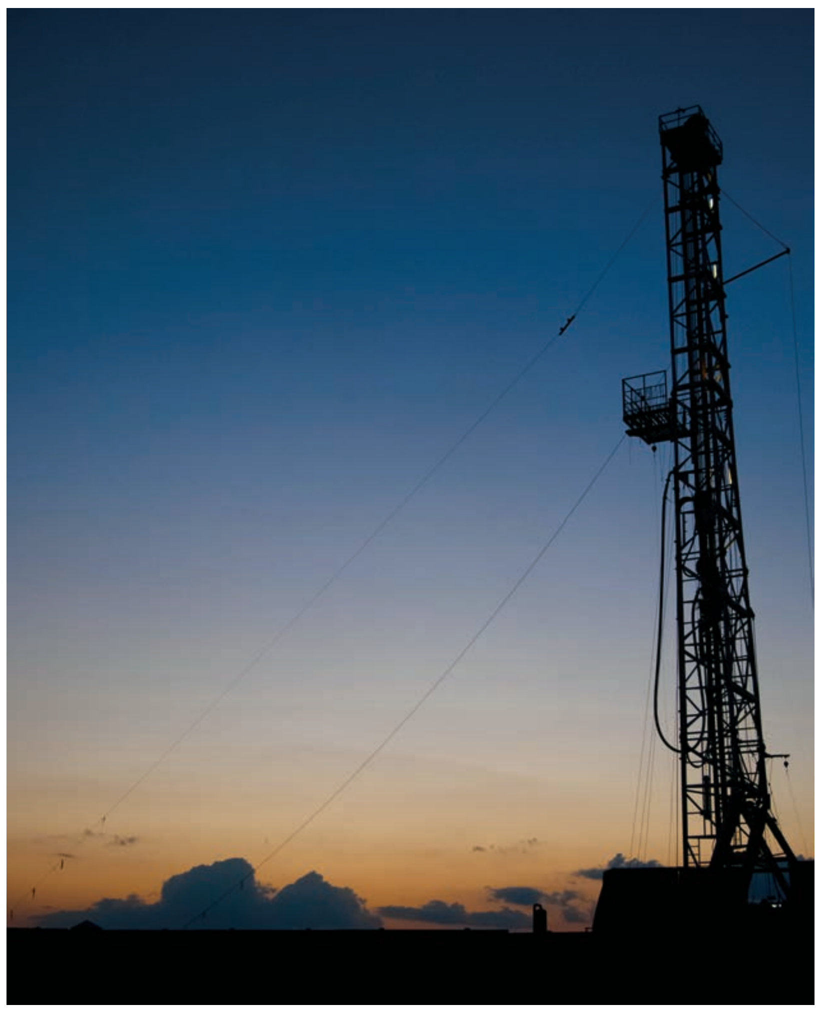
TABLE 1
Summary of Potential Reduction of Methane Pollution and Cost

Emission Sources and Control Strategies	Potential Reduction of Methane Pollution (metric tons per year)	Cost per Metric Ton of Avoided Methane Pollution including the Value of Saved Gas ($4/Mcf)
A. Leaks		
Leak detection and repair	1,700,000–1,800,000	$520–$1,200
B. Outdated Equipment		
Use zero- or low-bleed pneumatic equipment	720,000–870,000	$180–$230
Use modern designs and/or maintenance standards for compressor seals	480,000	-$47
C. Oil and Gas Well Venting		
Capture gas from oil wells instead of venting or flaring	140,000–380,000	-$81
Use properly managed plunger lifts, or other methods, to minimize venting when removing liquids from gas wells	120,000	-$87
Total Methane Abatement and Overall Average Cost	3,200,000–3,700,000	$290–$660

Source: CATF analysis.

exception of Petron *et al* (2014), which was not published at the time of Brandt *et al.*'s review). Brandt *et al.* demonstrates that for many years top-down studies have very consistently shown higher emissions from oil and gas compared to bottom-up studies. The authors' estimation of total U.S. methane emissions from all sources is 25 to 75 percent higher than the U.S. GHG Inventory estimated for 2011, and they find that oil and gas are important contributors to these unreported emissions.[19]

To put these figures in perspective, EPA's 2014 U.S. GHG Inventory estimates that the oil and gas sector emitted 7.8 million tons of methane in 2011. Brandt *et al.* finds that EPA underestimated total methane emissions from all sources by approximately 7 million to 21 million tons. The top-down studies do not currently allow precise quantification of emissions of methane from oil and gas at the national scale, and it should not be expected that all excess emissions are from this sector. However, based on the detailed analysis by Brandt *et al.* of the large body of top-down research, the discrepancies between estimates of emissions from these studies and the U.S. GHG Inventory, and Brandt *et al*'s finding that oil and gas is an important contributor to emissions that are missing from the bottom-up inventories, we conclude that methane emissions from oil and gas certainly could be twice as high as shown in the U.S. GHG Inventory, and may be even higher.



Gas well in Denton, Texas. This well sits across the street from a park, a hospital and a residential area.

BOX 1

STRUCTURE AND ANALYTIC APPROACH OF THIS REPORT

In this report, we bring together data from several sources, relying principally on documents from EPA and state regulators, and analyze it using a consistent approach to show that straightforward, feasible standards for emissions from a targeted set of measures, shown in Table 1 (p. 11), can reduce methane emissions from the oil and gas industry by half. We describe how the technologies and practices reduce emissions, how standards already require those technologies and practices for some facilities (but leave many other facilities uncovered, and therefore able to continue polluting unnecessarily), and how much the technologies and practices would cost.

Chapter Two of the report provides background on the oil and gas sector and what is currently understood about methane emissions from each segment of the industry.

Following this summary, we describe EPA's authority and duty to set standards for methane pollution from the oil and gas industry, and describe the state of current federal emission standards for the industry that focus on VOC emissions. Though the current VOC standards reduce some methane pollution, they do not address many of the industry's sources of methane emissions.

Chapter Three introduces the measures we propose and looks at how they can eliminate up to half of the methane emissions from the oil and gas industry in just a few years. For each measure, we describe the source of emissions, the current estimated level of emissions from that source, the technology or practice to reduce emissions, and how much the technology or practice can reduce methane pollution. Finally, we describe the costs of abating methane pollution from each source. We also include information about several oil and gas sector sources of methane pollution that were not addressed by EPA's white papers: outdated leaky underground gas distribution lines; tanks that store oil, condensate, and water from oil and gas wells; and natural gas dehydrators. However, potential methane emission reductions from these additional sources are not included in the figures for total abatement of methane pollution in this report's core analysis.

For the analysis in Chapter Three, we begin by using estimates of current emissions, primarily the values for 2012 from EPA's 2014 U.S. Greenhouse Gas Inventory[20] (which we refer to throughout this report as the "U.S. GHG Inventory") and other EPA data. We then use EPA or state regulator assessments of both the mitigation potential from control measures applicable to each source type and the cost of that mitigation. As we describe in the text, in a few instances we have used other data sources, when that other data is more recent or more applicable than the principal data sources. All data sources are noted in the Appendix, which also provides additional details regarding the analysis. Our abatement estimates are for current emissions, and we do not project the amount of abatement from these measures in future years. If U.S. production of natural gas increases as generally predicted, the methane abatement from these measures will be larger in future years.

As discussed, there is clear evidence that the U.S. GHG Inventory, and other bottom-up data sources, underestimate real emissions. The discussion of abatement potential from specific sources in Chapter Three does not account for this underestimation. Therefore, the figures we present in Chapter Three, both for current emissions and emission reductions from the specific measures we propose, are quite conservative.

Likewise, our cost figures for the measures we propose are generally conservative—meaning that they are likely to be higher than the actual costs of the measures. Our cost estimates are largely from regulatory analyses by EPA or Colorado. As discussed above, real emissions are very likely higher than estimated in official inventories, and thus higher than regulators assumed when preparing these cost estimates. The measures we propose therefore will typically reduce emissions by a larger amount than expected (see discussion of leaks below), in turn reducing the cost per ton of methane controlled.

Chapter Four presents a synthesis of our analysis. We discuss the total abatement from the highlighted measures—including an estimate of what the actual emissions reductions may be, taking into account the underestimate of emissions in current inventories. We also compare these pollution reductions to those that would result from other regulatory approaches for reducing air pollution from oil and gas.

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Shale gas well in Washington County, Pennsylvania.

CHAPTER 2

BACKGROUND

THE U.S. OIL AND GAS INDUSTRY—STRUCTURE AND CURRENT EMISSIONS

THE OIL AND NATURAL GAS industry includes activities ranging from the initial drilling and recovery of oil and natural gas to the delivery of the final product to customers. Methane is emitted by oil production and throughout all segments of the natural gas industry via leaks, venting sources (sources which release methane into the air by design), and other types of releases.[21] This report focuses on mitigation of leaks and venting sources.

EPA's U.S. GHG Inventory provides separate estimates for methane emissions from each segment of the oil and gas industry:

- Oil Production,
- Gas Production,
- Gas Processing,
- Transmission & Storage, and Distribution.

Because oil and gas production are often intertwined (many wells produce both oil and gas) and some data sources we use in our analysis are not specific to either oil production or gas production, we discuss oil and gas production as a single segment of the industry.

A summary schematic of the activities and emissions sources from each segment is shown in Figure 1 (p. 14). There are opportunities to reduce methane emissions in each segment at very reasonable costs.

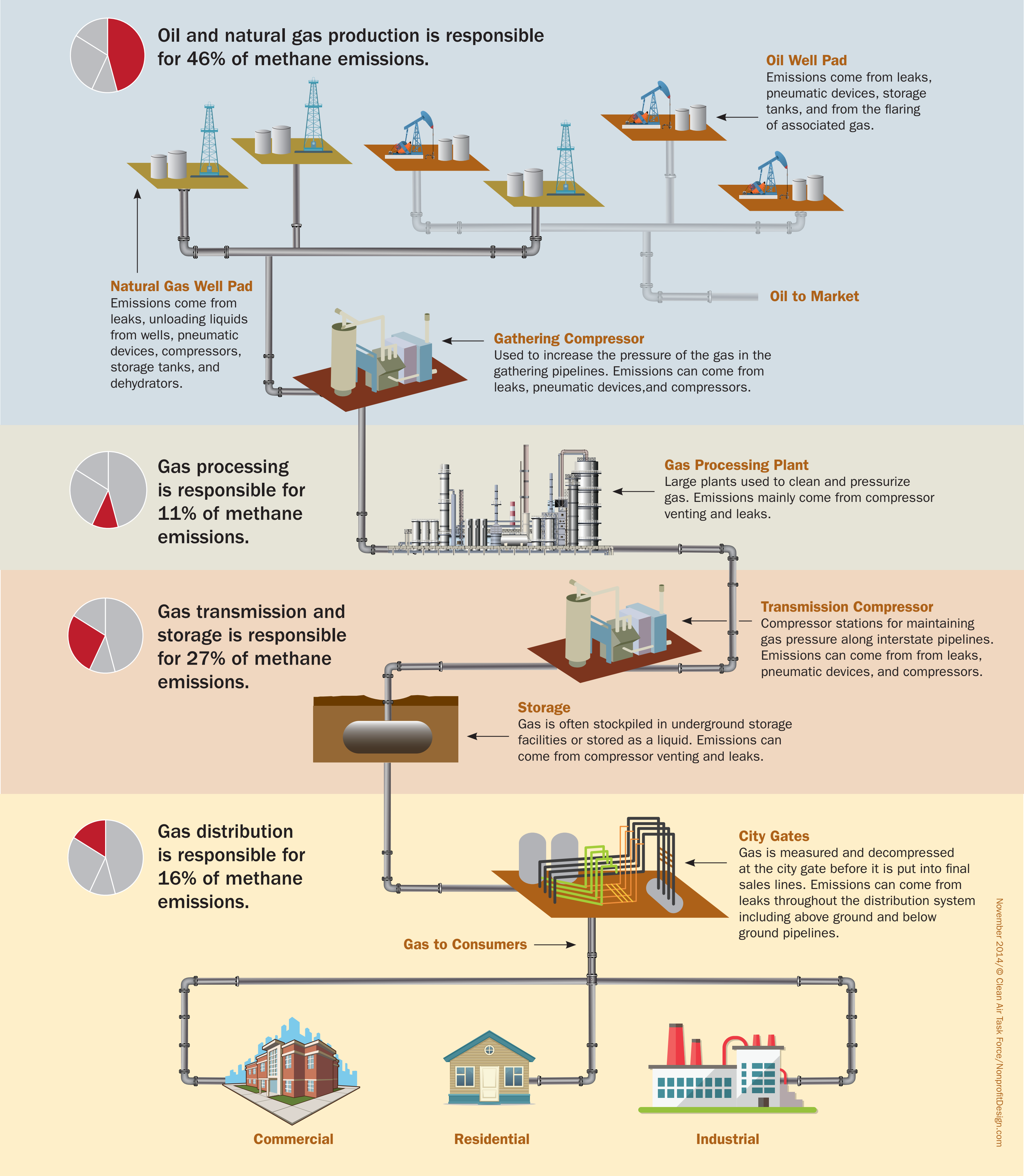
Oil and Gas Production

The oil and gas production segment includes many diverse activities, such as production of hydrocarbons from underground geologic formations; separation of natural gas, oil, and, water; and collection of gas from multiple wells through natural gas gathering

FIGURE 1

Emissions Come from All Segments of Natural Gas and Oil Development

Total Emissions (2014 EPA GHG Inventory) = 7.7 Million Tons of Methane



pipeline systems. These activities in turn involve processes such as well drilling, hydraulic fracturing or other stimulation for many wells, and well work-overs. These activities require equipment such as tanks, piping, valves, meters, separators, dehydrators, pipelines, and gathering compressors.

EPA's U.S. GHG Inventory estimates that the oil and natural gas production segments emitted just under 3,500,000 metric tons of methane in 2012. Emissions abatement opportunities for oil and gas production described in this report include finding and fixing leaks on wellpads and at gas gathering compressor stations; reducing emissions from existing, older gathering compressors, automatic pneumatic valve controllers, and pneumatic pumps; controlling venting of methane during well completion and production from oil wells; and reducing venting from older gas wells when water is removed from the well. These measures could reduce emissions from oil and gas production by at least 1,190,000 to 1,510,000 metric tons per year.

Natural Gas Processing

Gas processing plants separate raw natural gas into natural gas liquids and processed natural gas that meets specifications for transport in high-pressure pipelines and consumption in furnaces and power plants. Natural gas liquids are hydrocarbons such as propane, butane, etc., which are valuable products of gas processing.

The U.S. GHG Inventory estimates that the processing segment of the natural gas supply chain emitted about 900,000 metric tons of methane in 2012. Emissions abatement opportunities from gas processing plants described in this report include finding and fixing leaks from various processing equipment and reducing extensive emissions from compressors, which together could reduce annual emissions by at least 538,000 metric tons.

Transmission and Storage

Natural gas transmission pipelines carry gas from production regions to markets. This segment also includes facilities where gas is stored, either underground or as a liquid. Compressor stations along pipelines maintain pressure and provide the energy to move the gas.

The U.S. GHG Inventory estimates that the natural gas transmission and storage segment emitted over 2,000,000 metric tons of methane in 2012. Opportunities to reduce emissions include finding and fixing leaks from various pieces of pipeline equipment, as well as reducing emissions from

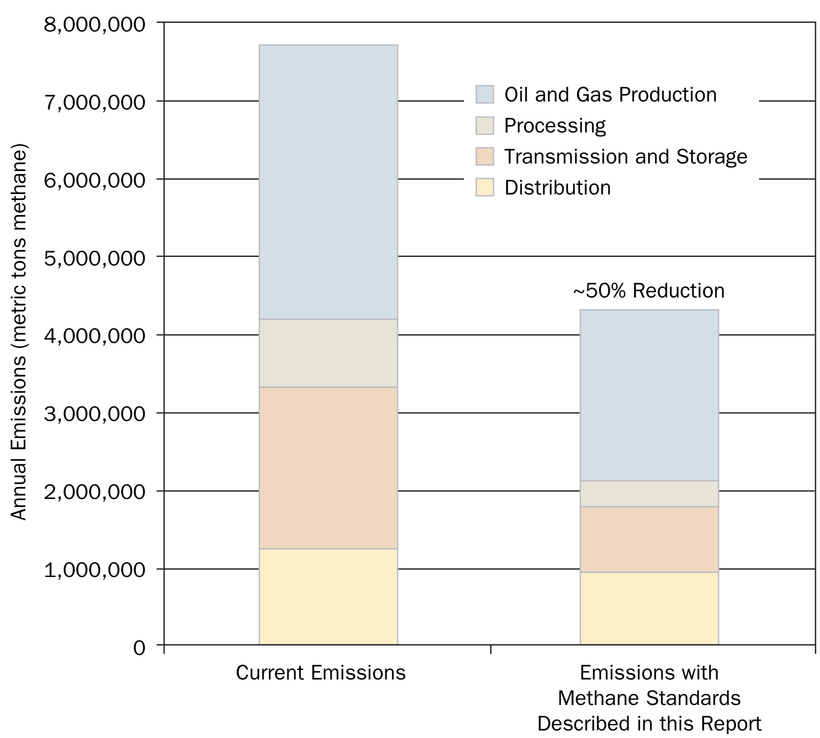
Finding and fixing leaks at large, aboveground distribution facilities could reduce emissions by at least 283,000 metric tons per year.

older compressors and pneumatic valve controllers, which together could reduce annual emissions by at least 1,180,000 to 1,330,000 metric tons.

Natural Gas Distribution

Finally, natural gas is delivered to customers (residential, commercial, and light industrial) via low-pressure underground distribution pipelines. The U.S. GHG Inventory estimates that gas distribution systems emitted over 1,200,000 metric tons of methane in 2012. Emissions from distribution can be reduced in the near-term by finding and fixing leaks at large, aboveground distribution facilities (such as metering stations and the facilities where gas is transferred from high-pressure transmission pipelines into low-pressure distribution systems). These measures could reduce emissions by at least 283,000 metric tons per year.

FIGURE 2
Potential Methane Reductions by Segment



Source: US GHG Inventory 2014 and CATF analysis.

Significant methane emissions reductions can be achieved from all segments of the oil and natural gas industry.

REGULATION OF METHANE FROM OIL AND GAS SOURCES

Following more than 40 years of action by EPA to limit air pollution under the Clean Air Act, Americans now breathe much cleaner air, the ozone layer that protects us from harmful ultraviolet radiation is recovering, and vulnerable ecosystems are rebounding as acid rain diminishes.

Because EPA has already found that methane and other greenhouse gases endanger public health and welfare, EPA has the duty to regulate methane under the Clean Air Act.

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Natural gas well in Pavillion, Wyoming.

The Clean Air Act also gives EPA the tools and the obligation to address the threat of climate change by reducing greenhouse gas emissions. In 2007, in *Massachusetts v. EPA*, the U.S. Supreme Court ruled that the EPA has the authority to curb heat-trapping pollutants under the Clean Air Act. If EPA found the science showed greenhouse gases endanger public health and welfare, the Court held, EPA must set standards to reduce the emissions from new cars and trucks, the source at issue in *Massachusetts v. EPA*.

During President Obama's first term, EPA found that the overwhelming scientific evidence shows that greenhouse gases, including methane, do indeed endanger public health and welfare. The federal courts upheld EPA's determination, and EPA issued standards to lower greenhouse gas emissions from new cars and trucks.

In 2011, the Supreme Court confirmed in a case entitled *American Electric Power Company v. Connecticut* that the Clean Air Act grants EPA authority to regulate emissions of greenhouse gases from categories of *stationary* sources. Because EPA has already found that methane and other greenhouse gases endanger public health and welfare, EPA has the duty to regulate methane under the Clean Air Act.[22]

Establishing methane "standards of performance" for the oil and gas industry under section 111 of the Act is appropriate given the major contribution the industry makes to national greenhouse gas emissions and the availability of proven, cost-effective emission reduction technologies. Once EPA establishes methane standards for new sources, the Act requires EPA to set guidelines identifying the best system of emission reduction for *existing* sources. Because the measures for controlling methane from existing sources are essentially the same as for new sources, EPA's guidelines can closely parallel its new source standards. Each state must then adopt a plan establishing and implementing the required emission standards for existing sources, and submit that plan to EPA for approval.

EPA is in the process of developing carbon dioxide standards under section 111 for the nation's power plants. Given the magnitude of the greenhouse gas pollution from the oil and gas sector—particularly from existing sources—and the availability of low-cost methods to reduce that pollution, regulation of methane emissions from this sector is a key to achieving the nation's climate goals.

BOX 2

EPA'S 2012 NEW SOURCE PERFORMANCE STANDARDS FOR THE OIL AND GAS SECTOR

EPA's 2012 New Source Performance Standards (NSPS) for the oil and gas sector aim at reducing VOC emissions from several types of sources in the industry, and as a "co-benefit" will reduce methane pollution somewhat, since the two pollutants are emitted together by many sources. The 2012 standards require companies to control VOC emissions from gas wells following hydraulic fracturing by using Reduced Emissions Completions. EPA estimates that this measure will reduce emissions of methane by 800,000 to 1,500,000 metric tons per year.[23] The standards also require the use of effective means for reducing VOCs from several types of new or modified equipment, such as new processing plants and compressors and automatic pneumatic valve controllers at certain types of facilities. These other measures will reduce methane emissions modestly.

However, the 2012 standards did not address the bulk of methane pollution from the industry due to several key omissions. Most critically, EPA did not directly regulate methane, instead opting for a VOC approach that severely limited the scope of the 2012 standards and kept EPA from cleaning up two major causes of methane emissions: downstream sources and existing equipment.

- Because the 2012 NSPS used only VOC emissions to determine whether to set standards for a particular activity or piece of equipment, they do not address the vast majority of sources in the transmission and storage segment of the industry, and leave sources in local gas distribution systems entirely unregulated. This omission occurred because these downstream sources have a lower ratio of VOC emissions to methane emissions than upstream gas production and processing equipment.

- Section 111 of the Clean Air Act requires EPA to address existing sources of "designated pollutants" like methane from source categories such as the oil and gas sector, provided that EPA has set standards for new sources of these pollutants.[24] Because EPA has not interpreted this authority as applying to VOCs, it did not set standards for the unmodified existing equipment that accounts for the vast majority of the sector's methane pollution. Outdated, excessively polluting equipment in place prior to the 2011 effective date for the 2012 standards therefore continues to operate without being cleaned up. Absent methane standards for these sources, it is likely that existing equipment will continue to needlessly pollute for many years to come, and in the case of some equipment like compressors, for decades. Indeed, a recent report projects that 90 percent of methane emissions occurring in 2018 will originate from sources already in operation in 2011.[25]

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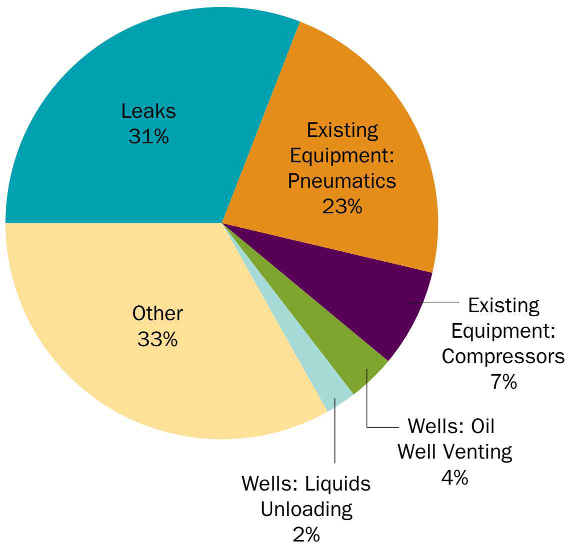
Hydraulic fracturing equipment at a natural gas well in Washington County, Pennsylvania.

EPA also did not address pollution from oil wells, such as completion emissions following hydraulic fracturing of oil wells, and venting and flaring of associated gas from oil wells during production, in the 2012 standards because it claimed it did not have sufficient data on VOC emissions from such sources.[26] Emissions from conventional gas wells, such as venting during liquids unloading, were also not addressed. Oil wells and liquids unloading emit an estimated 320,000 to 580,000 metric tons of methane and 160,000 to 400,000 metric tons of VOC each year. (See Chapter 3 for a discussion of current emissions from these sources).

In the 2012 rulemaking, EPA noted that it was not making a final decision regarding methane standards, and would use new data submitted through the Greenhouse Gas Reporting Program to aid the agency in considering the appropriateness of regulating methane moving forward.[27]

FIGURE 3
Sources of Methane Emissions in the Oil and Gas Industry



Source: US GHG Inventory 2014 and CATF analysis.

Emissions from the sources we focus on in this report make up two-thirds of the methane emissions in the oil and gas industry. "Other" sources include tanks, leaks from underground pipelines, compressor exhaust, etc.

In 2012 EPA finalized nationwide standards of performance for VOC emissions from oil and gas production, and updated rules for gas processing plants (the "2012 standards").* These VOC standards, which are still phasing in, will reduce methane emissions somewhat as a "co-benefit." However, EPA did not directly regulate methane emissions from oil and gas facilities when it issued the VOC standards, and as a result, as we describe in Box 2 (p. 17), EPA did not address sources responsible for the vast majority of the sector's methane pollution and harmful amounts of other air pollutants.Fortunately, EPA is currently revisiting its prior failure to regulate methane emissions from the oil and gas industry. In March 2014, President Obama released the "Strategy to Reduce Methane Emissions" as part of his Climate Action Plan. The Strategy identifies oil and gas emissions as the single largest industrial source of methane in the U.S., and commits EPA to "determine how best to pursue further methane reductions" from the sector, including assessing additional standards such as those under Section 111.

EPA took the first step of this assessment in April 2014 by issuing and seeking comment on technical white papers assessing significant sources of methane, and methods for reducing emissions from those sources. Many of our organizations submitted detailed technical comments on those papers to EPA in June 2014.[28] As shown below, the sources described in the white papers emit approximately two thirds of the methane from the oil and gas sector.

This report summarizes the significant, low-cost opportunities to reduce methane from oil and gas operations that EPA's white papers, and our comments on the white papers, describe. We examine the methane sources that EPA's white papers considered:

- Leaks—"fugitive" emissions from static components and seals that are designed not to release any gas.
- Older compressors and gas driven valve controllers and pumps that, by design, vent far more methane than newer, modern equipment.
- Release of gas from oil wells and gas wells during the completion and production phases.

Based on detailed analysis of data compiled by EPA, state regulators, and industry reports, we show that by simply requiring proven, practical measures to minimize emissions from these sources and keep natural gas in the system, EPA can reduce total methane emissions from the oil and gas sector by nearly one-half. These measures have low costs and are already in use in leading states and by forward-looking companies.

* 40 C.F.R. § 60.5360 *et seq.* At the same time as these performance standards under section 111 of the Clean Air Act were issued, EPA also set new regulations for the emissions of hazardous air pollutants from specific oil and gas industry sources under section 112 of the Act. The oil and gas rules under section 112, 40 C.F.R. § 63.760 *et seq.*, generally do not address emissions from the sources we focus on in this report, so when we refer to the "2012 standards" we are referring to the performance standards for emissions of VOC issued under section 111. EPA's official fact sheets describing the 2012 standards, and documentation and analysis supporting the standards, are available at *http://www.epa.gov/airquality/oilandgas/index.html.*

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CHAPTER 3

TECHNOLOGIES AND PRACTICES TO REDUCE METHANE POLLUTION

This section describes in detail the specific sources of methane pollution from the oil and gas industry that EPA should address with standards directed at methane under Section 111 of the Clean Air Act.

For each source type, we describe the source and current emissions. We then describe technologies and practices that can cut current emissions from these sources in half in a few years. As we describe, these technologies are proven and in-use. Many are required by current regulations for some facilities in some jurisdictions. All are in use by leading operators, as has been documented by EPA's Natural Gas Star Program and elsewhere. We demonstrate that EPA can set reasonable, commonsense standards to put these technologies and practices into use, in many cases following and expanding on examples set by states, and we estimate the total abatement that can be achieved. Finally, we provide an estimate of the abatement cost in each category.

Implementing these standards nationwide would be a critical step towards achieving our country's climate commitments.

As we noted above (see the discussion of Methodology in Chapter 1), the actual reductions in methane emission from these measures would be higher than reported in the following discussion, because these figures are derived from bottom-up inventories that underestimate actual methane emissions. For the same reason, the abatement cost figures are higher than the actual costs per ton of avoided methane pollution. Finally, these cost figures do not reflect the additional and substantial benefit in avoided climate change costs from reducing harmful methane, which we discuss in Chapter 4, or the avoided health and environmental costs from reducing smog precursors and toxic air pollutants.

Natural gas compressor station in the Powder River Basin in Wyoming. Emissions from compressor stations account for 25% of methane emitted by the oil and gas industry—570,000 metric tons is vented from compressor seals and 1,400,000 metric tons is leaked.

Finding and Fixing Leaks

Leaks for present purposes are characterized as the escape of natural gas from static components such as connectors, valves, regulators, and hatches throughout the oil and natural gas sector, where such escape does not constitute intentional venting as part of normal operations.[30] Such waste is widespread, and there is no single cause for these leaks. Thermal or mechanical stresses can degrade seals, as can human error (*e.g.*, improper installation, operation, or maintenance), while normal operations and exposure to weather conditions can wear out equipment over time. Leaks will eventually occur at all oil and gas facilities; failing to fix them in a timely matter is a wasteful and harmful practice that leads to clearly avoidable emissions.

While the U.S. GHG Inventory estimate of emissions from leaks at aboveground oil and gas facilities[31] is substantial, it is very likely an underestimate of actual emissions from leaks. As noted above (see Chapter 1), independent measurements have shown that emissions from oil and gas operations are higher than estimated by the U.S. GHG Inventory. It appears likely that one of the main sources of the unattributed emissions is very large, but uncommon, leaks (from sources often referred to as "super-emitters").[32] For example, one extensive study of emissions from gas processing plants found that 38 percent of all emissions from leaks and compressor seals at five plants came from *just seven leaks* out of the 70,000 components at the plants.[33] "Super-emitters," are very difficult to account for in "bottom-up" component-by-component analyses, such as those undertaken by EPA to calculate emissions from leaks, because they occur from such a small fraction of components, but nevertheless can significantly increase overall emissions.

Leak emissions can be reduced with rigorous leak detection and repair (LDAR) programs. These

FINDING AND FIXING LEAKS

POTENTIAL METHANE POLLUTION REDUCTION: 1.7–1.8 MILLION METRIC TONS PER YEAR

The U.S. GHG Inventory estimates that almost 2.4 million metric tons of methane leaks from static components at oil and gas well-pads, natural gas compressor stations, gas processing plants, and large aboveground gas distribution facilities every year.[29] This figure is almost certainly an underestimate of actual emissions from leaks. Requiring companies to regularly inspect their sites for leaks and fix them can substantially and cheaply reduce these emissions. Federal standards require other industries, such as refineries, to perform similar inspections, and some states have leak detection rules in place for a subset of oil and gas facilities. Infrared camera technology makes these inspections efficient from both technical and financial perspectives: once leaks are identified with low cost cameras, the repairs pay for themselves due to the value of the gas conserved.

EPA should require operators of these types of facilities to regularly inspect their facilities for leaks with instruments such as infrared cameras, and promptly repair the leaks that they find. We estimate that these standards would reduce methane emissions at a cost of $520 to $1,160 per metric ton of methane.

Gas processing plant, Texas. Every connection point in a processing plant is a potential leak, but they can be rapidly scanned using IR camera technology and fixed.

Methane released at these storage tanks is invisible to the naked eye, but it can be seen with an infrared camera.

programs require regular surveying of facilities for leaks using instruments that detect methane and other hydrocarbons in natural gas. While EPA rules for LDAR at natural gas processing plants built in the last 30 years require the use of detectors which must be held next to each individual component being surveyed, infrared (IR) cameras have become common tools to find leaks in recent years. They allow inspectors to directly image leaking gas in real time, with the ability to inspect entire components (not just connections and other areas most likely to leak).* IR cameras thus allow much more rapid leak surveys.

Several states already require common-sense LDAR programs for oil and gas operations. In February 2014, Colorado revised its air quality regulations for natural gas systems to require LDAR surveys at new and existing well production facilities and natural gas gathering compressor stations. Colorado's logical approach "tiers" the LDAR requirements based on emissions, requiring monthly inspections for the largest facilities, with successively less frequent inspections at successively smaller facilities.[34] Pennsylvania,[35] Wyoming,[36] and Ohio[37] require at least a portion of well facilities and gathering compressor stations to conduct LDAR surveys with IR cameras or other instruments regularly in order to obtain or modify a permit. While these state rules only address emissions from a portion of oil and gas sites within the respective states, they demonstrate that rules requiring LDAR are feasible and affordable for industry. National rules should build off of these state rules.

Following the analysis that Colorado used to support the state's recent rules, we estimate that regular (i.e., quarterly or monthly) LDAR will reduce methane emissions from leaks by 60 to 80 percent.[38]

The costs of LDAR surveys with IR cameras are very reasonable for two reasons: the survey cost is low, and once leaks are found, the cost of repairing the leaks is largely (or entirely) paid for by the value of the gas conserved by fixing the leak. Multiple sources report that survey costs are low. A recent study by the energy consultancy Carbon Limits[39] reports that it costs $400 to $1,200 to have an external firm perform an LDAR survey at a well facility, depending on the facility's size,[40] while calculations based on the data Colorado compiled during its recent rulemaking show costs of $820 to $860 per inspection.[41] Several oil and gas producers have reported that their own LDAR programs have significantly lower costs than these estimates. During the Colorado rulemaking, Noble Energy reported costs for a wellpad LDAR survey (performed in-house) of $263 to $431, while Anadarko reported survey costs from $450 to $800.[42] Similarly, Southwestern Energy has reported that LDAR surveys cost them less than a tenth of EPA's estimated implementation costs.[43]

Several studies have shown that repair costs are almost—or even entirely—paid for by the value of the gas conserved by the repairs.

Likewise, several studies have shown that repair costs are almost—or even entirely—paid for by the value of the gas conserved by the repairs. The

* IR cameras allow users to "see" leaking gases by creating images with infrared light, which is absorbed by natural gas, using technology similar to night vision glasses.

Carbon Limits study, which is based on analysis of records from over 4,000 LDAR surveys of oil and gas facilities, reports that 97 percent of the volume of leaks comes from leaks which are economic to repair, i.e., the revenues from the additional gas are greater than the cost of the repair.[44] Colorado's analysis used an entirely different method to predict that almost 80 percent of repair costs for well facilities will be covered by the value of conserved gas,[45] while Encana reported that the value of recovered gas has been greater than repair costs in their experience in Wyoming.[46]

And, as noted above, industry reports *lower* abatement costs than Colorado estimated. The state estimated that the tiered inspection rule will cost $1,259 per short ton of VOC abated at well sites.[47] In the comments cited above, Noble Energy predicted the VOC abatement cost of the rule would be about a tenth of that figure. Encana, in turn, reported in the testimony cited above that the company's *monthly* LDAR program in Wyoming has VOC abatement costs of less than $230 per short ton of VOC—again, about one-tenth of the VOC abatement cost that Colorado calculated for monthly LDAR. (Neither company reported their costs per ton of methane pollution abatement. However, their very low VOC abatement costs mean that their methane abatement costs will also be very low.)

Given low survey costs and very low net repair costs, finding and fixing leaks is an overall low-cost way to reduce harmful emissions. The Carbon Limits study found that monthly surveys of production facilities and gas processing plants cost $800 to $900 per metric ton of methane pollution prevented. Quarterly surveys cost even less (below $300 per metric ton of avoided methane pollution), but reduce emissions less in aggregate than monthly surveys.* Colorado's data for the costs of the state's rule, where inspection frequency is tiered to facility size, shows that the rule will have an overall net abatement cost of about $930 and $520 per metric ton of methane for well facilities and gathering compressor stations, respectively.[48]

ICF International's recent analysis of the methane abatement opportunities from oil and gas also reported that LDAR costs are quite low, in line with some of the low costs reported by industry. For example, ICF reports that quarterly LDAR surveys at transmission and storage compressor stations reduce methane emissions for only $118 per ton (not accounting for the value of gas kept in the system by repairing leaks).[49]

IR cameras allow inspectors to see leaks that are invisible to the naked eye.

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* Some local areas with ozone pollution close to or in excess of air quality standards require LDAR for some production facilities, but these rules only apply to a small portion of facilities nationwide, and they exempt facilities / components handling gas with low levels of VOC.

Despite the low cost and high value, LDAR surveys currently are not required for most oil and gas facilities. National LDAR standards for oil and gas are extremely limited—they only apply to gas processing units built since 1984 (exempting equipment at those plants that handles gas with low VOC concentration[50]) and a few other specific types of equipment.[51] Statewide rules (noted above) generally only apply to oil and gas production activities, omitting many other downstream facilities, and aside from Colorado only apply to new or modified facilities.** The lack of rules requiring LDAR surveys at most oil and gas facilities allows large-scale, wasteful, and harmful leaks.

RECOMMENDATION

EPA should require oil and natural gas companies to control leaks from all equipment at wellpads, gas processing plants, compressor stations, and large aboveground distribution facilities by carrying out regular instrument-based Leak Detection and Repair (LDAR) surveys. Survey frequency should be based on the size of the facility, with larger sites containing more potentially leaking components inspected more often, but even the smallest oil and gas facilities should be inspected for leaks with appropriate instruments at least annually. Once leaks are identified, they should be repaired promptly, with prompt instrument-based confirmation that the leak has been fixed.

Leak detection at a natural gas processing plant. Over 400,000 metric tons of methane is leaked at natural gas processing facilities each year.

TABLE 2

Methane Emissions Reductions Opportunities and Costs For Leaks

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement cost per ton of methane reductions (without value of conserved gas)	Cost per Metric Ton of Avoided Methane Pollution including the Value of Saved Gas
Production (tiered)	378,000	217,000–289,000	$1,100	$890
Processing (monthly)	409,000	327,000	$1,100	$840
Transmission & Storage (monthly)	1,130,000	901,000	$350–$1,600	N/A
Distribution (quarterly)	471,000	283,000	$620	$410

Source: CATF analysis. Current emissions are based on the U.S. GHG Inventory. Abatement potentials follow the estimates used in the Colorado rulemaking. Costs are based on Colorado rulemaking analysis, Carbon Limits report, and analysis of EPA data for the costs of LDAR at aboveground distribution facilities. Net abatement costs assume that gas is worth $4 per Mcf, except in transmission and storage, where we assume that facility owners do not increase revenue by decreasing natural gas losses. See appendix for details.

** This estimate includes a small discount from mitigation achievable from LDAR, because surveys will already take place at Colorado production facilities under the 2014 rules (5.8 percent of U.S. gas production occurred in Colorado in 2012). We do not discount for the other states with LDAR rules, because their rules do not apply to existing facilities.

BOX 3

REPLACING LEAKING UNDERGROUND DISTRIBUTION PIPELINES

The nation's underground natural gas distribution system includes over 96,000 miles of cast iron and unprotected steel mains and nearly 4 million cast iron and unprotected steel service lines, which connect mains to individual customers. This infrastructure is old and extremely leaky: for example, the U.S. GHG Inventory indicates that a mile of cast iron pipeline main will emit an estimated 240 Mcf of gas each year, while a mile of protected steel will leak only 3.1 Mcf. Taken together, these outdated pipes are estimated to emit a total of 400,000 metric tons of methane each year.[52] In addition to contributing to climate change, these leaks can pose safety issues in urban areas.[53]

Efforts to replace this aging infrastructure are already underway: nationally, companies are replacing approximately 3,100 miles of cast iron and unprotected steel pipeline mains each year. At this rate, it will take decades to replace all of these leaky, outdated pipes.[54] However, the rate of replacement varies dramatically from state to state, in part due to different state regulatory approaches. Given the very slow pace in some states, it may take far longer than thirty years to replace all of the leaky pipes buried in our cities, in the absence of policies that speed up this process.

Accelerating replacement programs, so that rates of replacement in all states match those of the most aggressive states, could significantly move up the timeframe for phasing out these unreliable and occasionally dangerous pipes. State legislatures and utility commissions traditionally responsible for overseeing natural gas distribution utilities can and should take up this challenge along with local distribution companies; at the same time, federal agencies with oversight obligations, such as the Pipeline and Hazardous Materials Safety Administration and the Federal Energy Regulatory Commission, should look at policy reforms to speed up pipeline replacement and reduce emissions.

We have not included estimates of abatement of methane or other pollutants from outdated underground mains, which were not covered in EPA's white papers, in the pollution abatement totals in this report.

ABATEMENT POTENTIAL

LDAR programs can reduce leaks by at least 60 to 80 percent. Given estimates of emissions from aboveground facilities, where data shows that LDAR is low-cost, nationwide LDAR rules for new and existing facilities could reduce emissions by 1.7 to 1.8 million metric tons of methane.**

CLEANING UP OUTDATED EQUIPMENT

POTENTIAL METHANE POLLUTION REDUCTION: 1.2–1.4 MILLION METRIC TONS PER YEAR

Each year, at least 2.2 to 2.4 million metric tons of methane is released by design from two types of equipment that are very common in the oil and gas industry: natural gas-driven pneumatic equipment and compressors. This venting is considered routine, but it is wasteful, as it can be reduced by applying proven technologies and practices that are in wide use. At present, federal standards require these technologies and practices nationwide for certain types of new equipment.

EPA should strengthen these standards and extend them to all compressors and pneumatic equipment throughout the industry, most notably to existing compressor and pneumatic equipment installed before the nationwide rules went into effect. Without such standards, the existing fleet of dirtier equipment will stay in place for many years, or decades—beyond the timeframe needed to meet our climate commitments. We estimate that these standards would reduce methane emissions at a cost of $90 to $120 per metric ton of methane.

Cleaning Up Outdated Equipment

REDUCING OR ELIMINATING VENTING FROM NATURAL GAS-DRIVEN PNEUMATIC EQUIPMENT

Gas-driven automatic pneumatic equipment uses the pressure energy of natural gas in pipelines to do work, such as control, open and shut valves, or operate pumps. This equipment is ubiquitous at oil and gas production, processing, and transmission facilities, and is designed to vent natural gas to the atmosphere. Based on the best data available, natural gas-driven pneumatic equipment vents 1.6–1.9 million metric tons of methane each year.[55]

Pneumatic valve controllers, which account for an estimated 1.3 to 1.5 million metric tons of methane emissions per year (see Technical Appendix), automatically operate valves based on factors like liquid level in a liquid-gas separator, pressure, or temperature. They can be classified based on whether and how rapidly they vent or "bleed" natural gas and whether they bleed continuously or intermittently (typically only when performing some function). *High-bleed controllers* are defined as those that *continuously* vent more than 6 standard cubic feet of gas per hour (scfh), while *low-bleed controllers continuously* vent less than 6 scfh.[56] *Intermittent-bleed controllers* are a broad class, with

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Natural gas processing plant in the Denver-Julesburg Basin in Colorado. Gas processing is responsible for 11 percent of methane emissions.

varying bleed rates (averaged over periods when the controller is venting and when it is not venting); as a class, intermittent-bleeds emit more than low-bleed controllers but less than high-bleeds. Finally, *zero-bleed controllers* vent no natural gas, by either utilizing compressed air or electrical power to operate instead of pressurized natural gas, or by capturing for further use the natural gas that would otherwise be vented. Some zero-bleed devices are powered with solar-generated electricity, while others require electricity from the grid or an on-site gas-powered generator, or air compressed with a natural gas-powered engine.

We use the term "high-emitting controller" for any pneumatic controller that emits more than 6 scfh, whether it bleeds continuously or intermittently. "Low-emitting controllers"—that is, controllers emitting less than 6 scfh, whether continuous- or intermittent-bleed—can serve many of the same functions of higher-emitting controllers, and can therefore replace the higher-emitting devices for these functions.[57] While regulations have largely focused on reducing emissions from (continuous) high-bleed controllers, facility owners report higher aggregate emissions from intermittent-bleed controllers than from high-bleeds to EPA's Greenhouse Gas Reporting Program. Significant emissions reductions can readily be achieved by replacing both continuous and intermittent types of high-emitting controllers.

The 2012 standards require operators to use low-bleed equipment when installing new continuous-bleed controllers at production facilities and zero-bleed equipment at processing plants.[58] However, these rules allow the tens of thousands of existing high-bleed controllers that were installed before October 2013 to remain in service,[59] and allow new installation of high-bleed controllers at gas transmission facilities. Furthermore, the 2012 standards do not limit emissions from new or existing intermittent-bleed controllers. Finally, outside of gas processing plants, they fail to require any use of zero-bleed technology, even though it would be feasible at many sites. As we discuss below, replacing continuous high-bleed (and some intermittent-bleed) controllers with zero- or low-emitting controllers to control methane is feasible at low cost throughout the industry.* Without rules covering

* The gaps in EPA's current standards for existing unmodified pneumatic controllers reflect the regulatory approach that EPA took in forging those standards, not any conclusion that reducing methane emissions from existing controllers, or controllers in the transmission and storage segments of the supply chain, would not be feasible or cost-effective. See Box 2 (p. 17).

existing controllers, high bleed controllers will remain in service for many years (or decades).[60]

In contrast to the 2012 standards, Colorado standards required operators to replace existing high-bleed controllers with low-bleed controllers in the urban portions of the Denver-Julesberg basin in 2009,[61] and in early 2014 the state required operators to replace all high-bleed controllers statewide by May 2015.[62] The 2009 Colorado standard contained provisions allowing operators to keep high-bleed controllers in service if they showed that doing so was necessary for "safety and/or process purposes."[63] *No operator requested such an exemption*,[64] and we are aware of no evidence indicating that these requirements have caused any operational problems. These replacements have reduced annual methane emissions in the Denver-Julesberg basin by thousands of tons per year.[65] Clearly, widespread replacement of high-bleed controllers with equipment that vents less natural gas is feasible.

While EPA only requires that new controllers be zero-bleed at processing plants, zero-bleed controllers are feasible at a far broader set of facilities.

High-emitting intermittent-bleed pneumatic controllers can also be replaced with lower emitting equipment. Intermittent-bleed controllers are used in many of the same applications as continuous-bleed controllers, and many high-emitting intermittent controllers can be replaced by low-bleed controllers. Further, properly designed intermittent bleed controllers can emit below 6 standard cubic feet per hour (scfh) in many applications.[66] Indeed, Wyoming requires that *all* pneumatic controllers be low-emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.[67] More specifically, the state requires that for any non-zero bleed pneumatic pumps at new or modified well pads, bleed emissions must be captured for sale or fuel, or controlled with an incinerator.[68] In a recent study of the methane abatement opportunities from oil and gas, ICF International estimated that 25 percent of high-emitting intermittent-bleed controllers in oil and gas production can be replaced with low-emitting devices.[69]

To analyze the potential methane emissions reductions from cleaning up pneumatic controllers, we used ICF's estimate that 25 percent of intermittent-bleed controllers can be replaced with low-emitting controllers. We further assumed that all bleed controllers at processing plants can be replaced with zero-emitting controllers, consistent with the 2012 standards, and that in other industry segments, 20 percent of bleed controllers can be replaced with zero-bleed equipment. While EPA only requires that new controllers be zero-bleed at processing plants, zero-bleed controllers are feasible at a far broader set of facilities. Many compressor stations, for example, have power available from the grid or from on-site generation, and with oil and gas production occurring in more urban environments, on-site power is quite feasible for many wellpads. For high-bleed controllers, we assume that 95 percent can be replaced (75 percent with low-bleed controllers and 20 percent with zero-bleed controllers). This assumption is conservative, given Colorado's experience that operators did not request any exemptions from the state's replacement mandate.

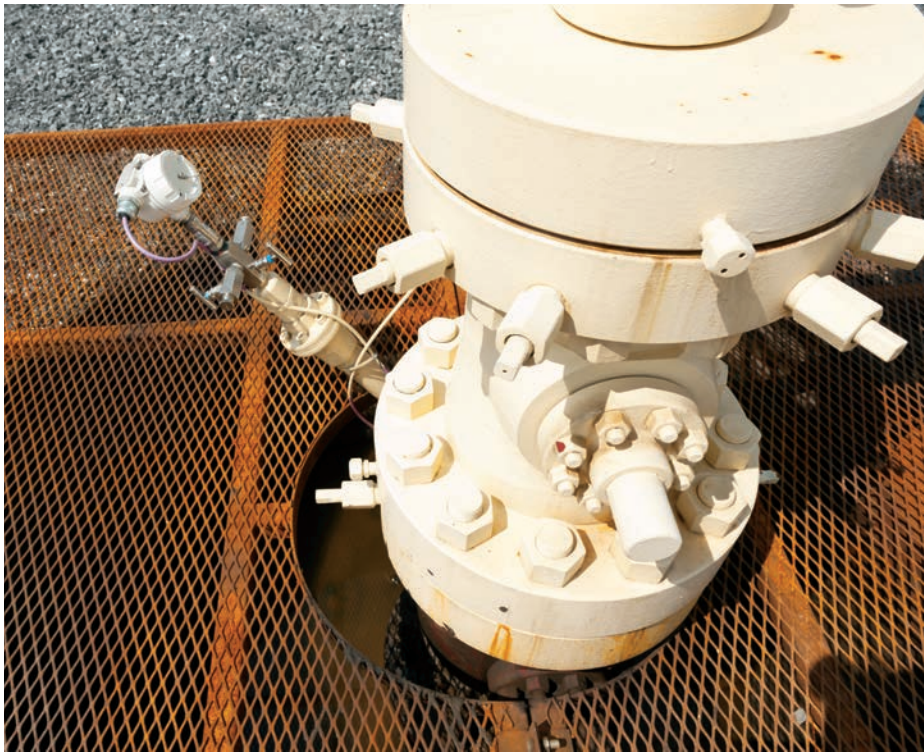
Replacing wasteful, high-emitting controllers is inexpensive. In many cases the extra revenue from sales of gas that would otherwise be vented is sufficient to pay for replacing high-emitting devices. EPA estimates that installing a new low-emitting controller costs $3,000 or less, and the annual value of gas conserved by replacing a high-bleed controller is around $1,100—thus, replacing this controller pays for itself in less than three years, yielding a negative cost to reduce methane emissions. Colorado found that costs for new low-emitting controllers are lower than EPA estimated and, as a result, calculated that replacing a high-bleed controller with a low-bleed controller pays for itself in just fourteen months.[70] Abatement costs per ton of avoided methane are somewhat higher for replacement of intermittent-bleed controllers with low-bleed controllers or replacement of either continuous high-bleed or intermittent-bleed controllers with zero-bleed controllers, but the aggregate cost of reducing methane emissions from controllers is very low (see Table 3).

Pneumatic pumps use the pressure of natural gas to supply the energy required to circulate and pressurize liquids. Chemical injection pumps are used to introduce liquid chemicals such as corrosion inhibitors into gas pipelines. Kimray pumps are used to circulate the liquids that absorb water in natural gas dehydrators. Together, these devices emit approximately 342,000 metric tons of methane per year, according to the U.S. GHG Inventory.

Electric pumps, which are commonly solar-powered for chemical injection pumps, completely eliminate methane emissions and are technically feasible in many locations. ICF International's recent methane abatement study reported that it would be feasible to replace 80 percent of chemical injection pumps and 50 percent of Kimray pumps with zero-emitting electric pumps.[71]

RECOMMENDATION

EPA should require the use of non-emitting valve controllers and pumps where feasible. Chemical injection pumps should generally be non-emitting; other pneumatic equipment should be zero-bleed for larger facilities or where electric power is available (such as in urban areas). When zero-bleed equipment is not feasible, pneumatic valve controllers should be low-emitting (less than 6 scfh), whether continuous- or intermittent-bleed. Exemptions should be allowed only upon adequate demonstration by facility operators that high-bleed devices are technically necessary.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Natural gas well in Pennsylvania.

ABATEMENT POTENTIAL

Replacing pneumatic controllers and pumps with proven zero- and low-emitting technology could reduce methane emissions by 723,000 to 871,000 metric tons per year. Current pneumatic equipment emissions, potential reductions, and costs for each segment of the industry are shown in the table below.

TABLE 3

Methane Emissions Reductions Opportunities and Costs for Pneumatic Equipment

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without Value of Conserved Gas)	Cost per Metric Ton of Avoided Methane Pollution including the Value of Saved Gas
Pneumatic Valve Controllers				
Production	1,290,000	508,000	\$550–\$610	\$310–\$370
Processing	1,480	1,480	\$740	\$510
Transmission & Storage	12,100–238,000	7,890–156,000	\$400–\$690	na
Pneumatic Pumps				
Production	338,000	204,000	\$140	-\$180
Processing	3,860	1,930	\$56	-\$260

Source: Current emissions are based on the U.S. GHG Inventory, the GHG Reporting Program, and Allen et al. (2013). Abatement potentials are calculated from those sources and the ICF International methane abatement study. Costs are based on analysis of data from Colorado's documentation for the 2014 rules, EPA's documentation for the 2012 standards, EPA's Natural Gas STAR, and data the ICF study. Net abatement costs assume that gas is worth \$4 per Mcf, except in transmission and storage, where we assume that facility owners do not increase revenue by decreasing natural gas losses. See appendix for details.

* This estimate includes a small discount from mitigation achievable from pneumatic controllers, because replacement of high-bleed controllers with low-bleed controllers will already take place at Colorado production facilities under the 2014 rules.

BOX 4

CONTROLLING EMISSIONS FROM OIL AND CONDENSATE STORAGE TANKS

Storage tanks are used to hold oil, condensate, and produced water from oil and gas wells. During normal operations, methane and other light hydrocarbons can separate from the liquids and, if not controlled, vent into the atmosphere. EPA estimates that storage tanks in the oil and gas production sectors account for 424,000 metric tons of methane emissions each year. Vapor recovery units (VRUs) can reduce emissions from storage tanks by 95 percent,[72] or over 370,000 metric tons.[73]

As part of the 2012 standards, EPA requires that *new* tanks with the potential to emit more than 6 tons per year VOC must reduce emissions at least 95 percent by capturing emissions or routing them to an incinerator.[74] Some older tanks are subject to earlier Federal rules, and several states have had rules in place for tanks for some time. (EPA's US GHG Inventory figures are adjusted to take these regulations into account.) However, hundreds of thousands of tanks are not covered by these regulations.[75]

Colorado's recent rules, unlike EPA's 2012 standards, cover both new and existing tanks—emissions controls are required at all types of tanks that have the potential to emit over six tons of VOC per year without control.

Tanks are also a very large source of VOC and toxic air pollutants—calculations based on EPA's US GHG Inventory suggest that tanks are emitting over *half* of the VOC emitted by the entire sector, and over a quarter of the toxic pollutants.[76] Control measures to reduce methane will generally reduce these other pollutants, and vice versa.

Calculations based on EPA data suggest that installing a VRU reduces methane emissions for about $990 per metric ton.[77] ICF International's recent methane abatement study reported far lower costs for using VRUs, from $33 per ton of methane abatement to net savings for operators (negative costs).[78]

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Oil tanks near a well in McKenzie County, North Dakota. Each year, oil tanks emit approximately 260,000 metric tons of methane, 1,200,000 tons of VOCs, and 35,000 tons of toxic air pollutants.

Note: We have not included estimates of abatement of methane or other pollutants from tanks, which were not covered in EPA's white papers, in the pollution abatement totals in this report.

REDUCING COMPRESSOR SEAL EMISSIONS

Seals on natural gas compressors are a significant source of preventable methane emissions. Current methane emissions from these seals are estimated at over 560,000 metric tons annually, based on the U.S. GHG Inventory and studies it cites.[79] Proven methods and technologies can reduce theses emissions by large amounts at low cost.

Reciprocating compressors use reciprocating pistons to compress gas. These compressors have seals on the connecting rods that transmit motion to the pistons inside the high-pressure cylinders; these seals are often referred to as rod packing and are a large source of emissions. Even when new, the seals let some gas escape. Over time they wear out. If not regularly replaced, emissions can become very large: the older the seals are, the more methane they emit.

Fortunately, these methane emissions can easily be reduced. First, proper maintenance practices—regular replacement of rod-packing—minimize emissions and should be required. EPA's 2012 standards require operators of *new* compressors at gathering compressor stations or processing plants to replace rod packing every 36 months or 26,000 hours of operation.[80] An available additional or alternative approach is to capture gas that escapes from rod packing and utilize it, such as by adding it to the fuel/air mixture for the compressor engine. This can be a superior approach since some gas escapes even from newly installed rod-packing, and EPA is currently considering allowing operators to use the emissions capture approach as an alternative to regular rod packing replacement for new compressors subject to the 2012 standards.[81] Unfortunately, EPA's 2012 standards exempt all compressors existing before 2011, as well as new compressors on wellpads and in the transmission and storage industry segment.[82]

Centrifugal compressors use a spinning turbine to pressurize gas. The rapidly rotating main shaft of the compressor is generally sealed with one of two technologies. *Wet seals* circulate oil to seal the narrow gap between the shaft and its housing. This oil absorbs significant amounts of the high-pressure natural gas that must be removed from the oil before recirculation. Typically, the gas removed from the seal oil is vented, resulting in substantial emissions: a typical wet-seal at a single centrifugal compressor vents nearly 356 metric tons of methane per year.[83] *Dry seals,* in contrast, use a more modern design to avoid the use of seal oil, with much lower emissions.[84]

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Compressor equipment at a natural gas well in Washington County, Pennsylvania. Well pad and gathering compressor emit over 52,000 metric tons of methane each year—5,000 metric tons from compressor seal vents and 47,000 metric tons from leaks.

EPA's 2012 standards require new centrifugal compressors located at gathering compressor stations or processing plants to use dry seals or reduce emissions by 95 percent by redirecting gas that would be vented from the oil of a wet-seal compressor back into the pipeline system or otherwise use it beneficially. Like the rules for reciprocating compressors, centrifugal compressors installed before 2011 and those in the transmission and storage industry segments are entirely exempt.[85]

Methane emissions can be cheaply and substantially reduced by extending the common-sense 2012 standards to all new and existing compressors at wellpads, gathering compressor stations, processing plants, and transmission and storage compressor stations. All reciprocating compressors should be subject to the maintenance standards in the 2012 standards, or gas from rod-packing seals should be captured as EPA has recently proposed for new compressors. Existing wet seal centrifugal compressors can be refit with dry seals, but generally it is cheaper to refit wet seals with systems to redirect gas back into pipelines or to beneficial use. Colorado's 2014 rules require existing reciprocating and centrifugal compressors at gathering compressor stations, and centrifugal compressors at wellpads, to utilize these proven measures to reduce emissions.[86]

TABLE 4
Methane Emissions Reductions Opportunities and Costs for Compressors

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without Value of Conserved Gas)	Cost per Metric Ton of Avoided Methane Pollution including the value of saved gas
Production	5,100	2,670	$270	$21
Processing	240,000	207,000	$41	–$200
Transmission & Storage	321,000	270,000	$66	na

Source: Current emissions are based on the U.S. GHG Inventory and studies cited by the Inventory. Abatement potential and costs are based on data from EPA's documentation for the 2012 standards. Net abatement costs assume that gas is worth $4 per Mcf, except in transmission and storage, where we assume that facility owners do not increase revenue by decreasing natural gas losses. See appendix for details.

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Compressor station in Macomb County, Michigan. Methane emissions from compressor seals amount to over 560,000 metric tons each year.

Maintaining an existing reciprocating compressor costs the same as maintaining a new compressor,* and EPA calculated that the compressor maintenance standards required by the 2012 standards for some new compressors would cost $84 to $270 per metric ton of avoided methane emissions.[87] EPA also showed that systems to capture emissions from wet seal compressors are very inexpensive: $16 per metric ton of methane in the production segment, and $29 per metric ton of methane in the transmission/storage segment.[88]

Compressors last for decades—manufacturers market them as lasting 30 or more years before being replaced, and extensive rebuild programs are available. The potentially long in-service life of a compressor is compounded by the fact that EPA's 2012 standards allow a compressor not subject to the rules (any compressor installed before 2011) to be moved to a new location and remain unregulated.[89] Therefore, a completely new compressor station can have a compressor that has been moved from a decommissioned facility, evading the common-sense provisions that the 2012 standards require of new compressors. If EPA does not require cleanup of methane and other pollution from these existing compressors, they will continue to excessively pollute for decades.

RECOMMENDATION

EPA should extend the 2012 standards requirement for proper maintenance to all new and existing compressors by requiring compressor operators to replace rod packing every three years or to capture gas from rod packing for use. EPA should also require that all new and existing centrifugal compressors with wet seal systems reduce methane emissions by capturing gas from oil degassing units or replacing the wet seals with dry seals. These requirements should include all compressors in segments of the supply chain that were excluded from the 2012 standards.

ABATEMENT POTENTIAL

Regular replacement of rod packing at reciprocating compressors could reduce methane emissions from these sources by 79 percent, resulting in emission reductions of 251,000 metric tons each year.** Capturing gas from the degassing units on wet seal compressors can reduce emissions from these compressors by 95 percent, which could reduce nationwide methane emissions by 229,000 metric tons per year. Current compressor emissions, potential reductions, and costs for each segment of the industry are shown in the Table 4.

* As discussed above for pneumatic controllers, the exemption of existing unmodified compressors from the 2012 standards reflects the regulatory approach that EPA took in forging those standards, not any conclusion that reducing methane emissions from existing compressors, or compressors in the transmission and storage segments of the supply chain would not be feasible or cost-effective. See Box 2.

** This estimate includes a small discount from mitigation achievable from compressors because Colorado rules require operators to comply with OOOO for existing production compressors in the state.

BOX 5

REDUCING DEHYDRATOR VENTING

Dehydrators remove water from the natural gas stream. When emissions from glycol dehydrators, the type most commonly used, are not controlled, the dehydrators vent a large amount of methane and other pollutants. Venting from dehydrators during natural gas production and processing results in an estimated greater than 36,000 metric tons of methane emissions each year according to the U.S. GHG Inventory. EPA's toxic air pollutant standards issued in 2012 impose requirements on some small dehydrators, and like storage tanks, dehydrators are subject to further standards in some states and local air districts. However, many smaller dehydrators remain unregulated.

Like tanks, dehydrators are also large sources of VOC, and particularly large sources of toxic air pollutants—dehydrators are the source of about a third of the entire oil and gas industry's toxic air emissions.[90] Cleaning up methane from dehydrators will reduce HAP emissions too, with important benefits for air quality.

Colorado recently updated standards covering glycol dehydrators at production facilities, compressor stations, and gas processing plants.[91] These standards will require operators of glycol dehydrators in the following categories to reduce emissions by 95 percent, and 98 percent in some cases:

- all new dehydrators that have uncontrolled emissions greater than 2 tons VOC per year,
- all existing dehydrators that have uncontrolled emissions greater than 6 tons VOC per year, and
- all existing dehydrators located near occupied buildings, playgrounds, or other outside activity areas with uncontrolled emissions greater than 2 tons VOC per year.[92]

There are a number of approaches to reducing emissions from dehydrator venting, such as adjusting circulation rates of the glycol fluid; routing the vent gas to a burner used to heat the glycol, so methane and toxics are combusted; use of a condenser to capture heavier VOC and toxics from the vent gas (which does not capture methane); and routing emissions to a flare or incinerator. Colorado requires the use of a condenser or a combustor to reduce these emissions.[93]

Colorado calculated abatement costs for the use of a combustor to control emissions to be $632 to $786 per ton VOC.[94] EPA's Natural Gas Star, focusing on other technologies to reduce emissions of methane, has found that a number of measures that reduce emissions of methane and other pollutants have payback times of a few months to a few years, depending on the size of the dehydrator and other design factors.[95]

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Natural gas production facility near Rhome, Texas. Dehydrators at natural gas production and processing sites emit approximately 36,000 metric tons of methane, 100,000 tons of VOCs, and 58,000 tons of toxic air pollutants each year.

Note: We have not included estimates of abatement of methane or other pollutants from dehydrators, which were not covered in EPA's white papers, in the pollution abatement totals in this report.

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Reduced emission completion equipment at hydraulically fractured natural gas well in Washington County, Pennsylvania. EPA's 2012 standards required operators to use Reduced emission completion equipment during natural gas well completions, which significantly reduces emissions during this process. However, completions at hydraulically fractured oil wells were not covered by this requirement.

VENTING FROM OIL AND GAS WELLS

POTENTIAL METHANE POLLUTION REDUCTION: 260,000–500,000 METRIC TONS PER YEAR

While EPA's 2012 standards require operators to capture natural gas that might otherwise be vented during completion after hydraulic fracturing of gas wells, data from EPA and other sources shows that venting of gas from oil wells and natural gas wells is still a large concern. Excluding emissions from gas well completions, oil and gas wells currently vent 324,000 to 580,000 metric tons of methane per year. These emissions come from release of gas during flowback after hydraulic fracturing of oil wells, from intentional venting of associated gas from oil wells during production, and from venting of gas wells during production to get water out of the well. These figures only include emissions from venting, and do not include emissions from the widespread practice of flaring natural gas, particularly associated gas from oil wells. We discuss flaring below, in Box 6. These emissions can be addressed with proven technologies that are widely adopted, such as reduced emissions completions for oil wells, capturing gas co-produced with oil instead of flaring it, and technologies that efficiently lift water out of gas wells without venting gas.

EPA should issue standards requiring operators to capture gas from wells instead of dumping it in the air or flaring it, and significantly reduce venting emissions during liquids unloading from the highest-emitting wells. These standards would have an estimated cost from $84 per metric ton of methane reductions (that is, cost savings for operators) to $91 per metric ton.

Venting from Oil and Gas Wells

REDUCING VENTING FROM OIL WELLS

Venting of gas during oil well completion flowback, following hydraulic fracturing of oil wells. EPA's 2012 standards address emissions from gas wells during flowback after hydraulic fracturing or re-fracturing.[96] Beginning on January 1, 2015, gas that flows to the surface during flowback from most gas wells must be separated and directed into pipelines as soon as practicable.[97] Before this date, all covered wells not capturing gas for sale must, at a minimum, flare it.[98]

This flaring and capture requirement does not extend to hydraulically fractured *oil* wells.[99] An analysis of multiple datasets by the Environmental Defense Fund has shown these oil wells produce 16 to 200 metric tons of methane for each completion/re-completion,[100] demonstrating that emissions from hydraulically fractured oil well completion are substantial if this gas is not captured or controlled. Furthermore, there is clear evidence from one dataset EDF analyzes (EPA's Greenhouse Gas Reporting Program) that methane is vented, instead of being captured for sale or flared, in a significant fraction of hydraulically fractured oil well completions, and only rarely is it captured for sale. Of the 957 well completions and re-completions with clear data on the handling of the gas produced during completion, 467 were vented and only 186 were captured (the balance were flared).[101] With high volumes of methane production per hydraulically fractured well completion, and an industry pattern of venting the emissions from a significant portion of these completions, we estimate that current methane emissions from hydraulically fractured oil well completions are 96,000 to 247,000 metric tons per year.[102] Moreover, given the dramatic growth in unconventional oil development in the past few years, we anticipate dramatic annual increases in methane emissions from oil well completions with hydraulic fracturing in the near future in the absence of appropriate federal standards.

Fortunately, there are low-cost and effective waste mitigation measures for this source. The same Reduced Emissions Completions (REC) approach to gas well completions—whereby operators capture natural gas with specialized equipment and direct it into pipelines, instead of allowing it to escape into the air—can be applied to associated gas produced during oil well completions. In 2012 EPA concluded that RECs can reduce gas well completion emissions by 95 percent.[103] RECs are

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Oil production well and flare in North Dakota. Methane venting during oil well completion and oil production is between 150,000 and 402,000 metric tons each year.

just as effective for oil wells as for gas wells, and recent research suggests that when properly carried out, RECs reduce methane emissions from both types of wells by more than 95 percent.[104] Oil producers must ensure that pipelines and related infrastructure are in place prior to completing wells, and use RECs to capture and direct gas into pipelines. We estimate that this measure will reduce annual methane emissions by 91,000 to 235,000 tons, with a net savings (or negative abatement costs) for oil producers.[105]

Venting of natural gas during oil production. U.S. oil companies vented and flared over 200 billion cubic feet of gas at oil wells during the production phase in 2013, enough to heat 3.4 million homes.[106] This waste occurs when oil producers, driven by the rush to sell oil, simply dispose of the gas from producing oil wells instead of building infrastructure (such as pipelines) to capture gas as soon as production begins. (In some cases, pipelines are never built and all of the gas the well produces over its lifetime is wasted in this way, as can be seen in sales records for individual wells available from state regulators.) While a substantial portion of this gas is flared off—wasting energy and producing large amounts of carbon dioxide and other pollutants—some is just dumped into the air, or vented. Venting is even more harmful than flaring, since methane warms the climate so powerfully, and VOC and toxic pollutants are released unabated.

TABLE 5

Methane Emissions Reductions Opportunities and Costs for Oil Wells

Emission Source	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per ton of Methane Reductions (without Value of Conserved Gas)	Cost per Metric Ton of Avoided Methane Pollution including the Value of Saved Gas
Oil Wells – Completions	96,000–247,000	91,200–235,000	$120	–$130
Oil Wells – Production Venting	50,800–155,000	48,200–148,000	$16	$16

Source: Current emissions are based on EDF analysis for oil well completions and GHG Reporting data for Production Venting. Costs are based on ICF International (2014) costs for REC (for completions) and flaring. Abatement potential is based on a 95% reduction from gas capture, or flaring as a last resort. We assume that for well completions, gas is captured and sold via pipeline, and credit the value of that gas ($4/Mcf) against the cost of REC. For production venting, although gathering gas or utilizing it through other means is generally profitable, we conservatively do not include any credit for the value of the gas. See appendix for details.

Under the GHG Reporting Program, producers have reported venting 51,000 to 155,000 metric tons of methane per year from producing oil wells in the years 2011 to 2013;[107] because not all oil and gas producers report emissions to this program, these figures are certainly underestimates of national emissions from oil well venting.

There are numerous cost-effective (and usually profitable) ways to utilize natural gas from oil wells. Only in the most extreme cases should oil producers be allowed to flare gas, and it should be strictly a temporary measure.

Venting of this gas should be prohibited in all cases as an absolutely unnecessary source of harmful air pollution. EPA should also ensure that all gas produced from oil wells is beneficially used (in onsite equipment) or transported to markets. As described in Box 6 (p. 36), there are numerous low-cost (and usually profitable) ways to utilize natural gas from oil wells. Flaring should be a last resort: only in the most extreme cases should oil producers be allowed to flare gas, and it should be strictly a temporary measure. Rules prohibiting venting of natural gas can easily reduce emissions by 95 percent, and can do so cheaply. While gathering associated gas with pipeline systems or using the alternative technologies described above are generally profitable, we conservatively use a cost of $15 per metric ton of avoided methane emissions (an estimate of the cost of flaring)[108] as an estimate of the overall cost of eliminating methane emissions from associated gas venting.

RECOMMENDATION

EPA should require that hydraulically fractured and re-fractured oil wells utilize reduced emissions completions (green completions) to capture associated methane gas, rather than venting or flaring. EPA should also require oil wells to capture and utilize associated gas during well production. Venting of gas should be prohibited; flaring of associated gas should only be allowed as a last resort, with stringent limits on duration of flaring and technology requirements to ensure that flares burn associated gas as completely as possible, minimizing emissions of air pollutants such as VOC, nitrogen oxides, and particulate matter.

ABATEMENT POTENTIAL

Oil well venting emissions could be reduced by 95 percent with gas capture,[109] reducing methane

Sergeant Major oil well in Arnegard, North Dakota.

TABLE 6
Methane Emissions Reductions Opportunities and Costs for Liquids Unloading

Emission Source	Current Emissions (metric tons/yr)	Potential Reductions	Abatement cost per ton of methane reductions (without value of conserved gas)	Cost per Metric Ton of Avoided Methane Pollution including the Value of Saved Gas
Liquids Unloading – wells without a plunger lift	80,600	51,800	$120–$450	($110)–$220
Liquids Unloading – wells with a plunger lift	96,800	68,000	$170–$660	($78)–$410

Source: Current emissions and abatement potential are based on the GHG Reporting Program. Costs are based on EPA Natural Gas Star Lessons Learned documents. Abatement potential is based on abating wells emitting over 300 Mcf per year 80% (for those with plunger lifts currently installed) and 90% (for those without plunger lifts); see text. Price of gas=$4/Mcf. See appendix for details.

emissions by 139,000 to 383,000 tons each year, (depending on the magnitude of current emissions).

REDUCING VENTING FROM GAS WELLS DURING LIQUIDS UNLOADING

Wells are commonly vented to the air during ongoing production operations to remove water that has built up in the well. Under EPA's GHG Reporting Program, industry reported emissions of 177,000 tons of methane from such liquids unloading in 2013, but this is an underestimate of national emissions since some gas producers are not subject to this program. Emissions from this source may be significantly underestimated.[114]

When water from the underground formations that produce gas accumulates in a mature gas well, it can slow or stop gas production from that well. In order to maintain production, operators remove, or "unload", liquids through a variety of methods, some of which vent natural gas to varying degrees. These methods include

- Installing pumps to lift liquids.
- De-clogging the well by entraining more liquid into the gas flow. Soap can be injected into the well to foam the liquids, or smaller diameter tubing can be installed in a well, increasing the gas velocity up the well.
- Installing a plunger lift, a simple device that efficiently lifts a column of liquid out of a well.[115]

Unfortunately, some operators forego these proven, affordable approaches to liquids unloading and crudely "blow down" the well by opening it to the atmosphere. Since atmospheric pressure is lower than the pressure in gathering pipelines, this practice can increase the flow rate in the well, allowing some portion of the liquids to reach the surface entrained with the high rate gas flow. However, this approach is inefficient, as it vents large quantities of gas while only removing a small portion of the liquids in the well.[116] In other cases, plunger lifts are installed on the well, but operated inefficiently, so that venting emissions are higher than need be. Proper adjustment and use of up-to-date management practices, such as "smart" adaptive learning automation systems, can dramatically reduce venting from wells where plunger lifts are installed but (without these up-to-date practices) venting remains high.[117]

The need to unload liquids is not unusual; almost every gas well will need to unload at least once during its productive lifetime, and some require many unloading events every year.[118] Unfortunately, many operators do not adequately plan and invest in technologies for liquids unloading. Federal rules do not require them to do so, instead allowing well operators to vent gas during unloading without limit. Colorado and Wyoming require operators to use best management practices for liquids unloading, but do not otherwise limit emissions.[119]

The vast majority of emissions from liquids unloading venting come from a very small number of high emitting wells. Our analysis of the GHG Reporting Program data for 2013 shows that approximately 12,000 wells (less than 22 percent of wells that vent during liquids unloading, and 2.5 percent of all gas wells nationwide) are responsible for more than 80 percent of liquids unloading emissions nationwide.[120] The *lowest emitting* well in this cohort releases 300,000 cubic feet per year into the air—around 1 Mcf methane per day, or nearly a half-ton each month. About 7,500 of the wells in this cohort have plunger lifts installed; they emitted about 85,000 tons of methane in 2013.

BOX 6

FLARING OF NATURAL GAS AT OIL WELLS

In this report we focus on emissions of methane from leaks and deliberate venting of natural gas. A related—and rapidly growing—problem is flaring of natural gas, particularly at oil wells. This typically occurs when oil producers dispose of natural gas at wells that are drilled to produce oil, instead of building the proper infrastructure to capture the natural gas that the well produces.

The use of hydraulic fracturing and other unconventional techniques has led to a rapid expansion of oil production in the U.S., and with this expansion, flaring has become a growing problem. The growth of flaring has been particularly alarming in North Dakota, as seen in Figure 4 (below). Over the past year, North Dakota oil producers flared enough gas to supply all the homes in Wisconsin or Massachusetts, producing almost 13 million tons of carbon dioxide pollution (more CO_2 than three coal-fired power plants).[110] Flaring is also common in south Texas's Eagle Ford shale region and other areas where oil production is rapidly increasing. In addition to CO_2, flares also produce other pollutants—soot and other harmful forms of particulate matter, as well as nitrogen oxides and other precursors of ozone smog. Often flares are very crude and do not burn well, making emissions even worse.

State regulation of flaring varies in stringency. North Dakota recently took significant steps to tighten its flaring rules, an important development given the huge volumes of gas flared in the state. However, the new regulations leave significant room for improvement, as they will not require operators to reduce the portion of the gas they produce that is flared below 10 percent, and they do not address flaring during the first three months after well completion, when flaring rates are typically the highest.[111] Given the growth in gas production in North Dakota as more and more wells are drilled, it is not clear that the total amount of gas flared by oil producers will actually fall, even as the fraction flared drops.

EPA should address the wasteful and polluting practice of flaring. There are many ways to utilize natural gas from oil wells economically—and almost always, profitably. In many cases, pipelines can be built to economically transport gas, even when gas production is low.[112] Beyond gathering the gas with pipelines, gas can be used productively in a number of ways. It can be used in on-site generators to power equipment for local use (such as drilling nearby wells), or the power can be exported to the electrical grid. Gas can be compressed with field units for use as truck fuel, or to be trucked in compressed gas tankers to locations where it can be used or transferred into gas gathering systems. It can be chemically transformed on-site into useful liquids such as methanol, which are easier and cheaper to transport than natural gas. And finally, portable units can remove valuable natural gas liquids (NGLs) from associated gas. After the removal of NGLs (which are typically trucked out for sale), the residual gas can be more easily used in the applications listed above, since high NGL content can interfere with some

FIGURE 4
Carbon Dioxide Pollution from North Dakota Flaring

Source: North Dakota Industrial Commission/CATF Analysis.

Flaring in North Dakota—and pollution from flaring—have increased dramatically in the past few years.

The use of hydraulic fracturing and other unconventional techniques has led to a rapid expansion of oil production in the U.S., and with this expansion, flaring has become a growing problem. Often flares are very crude and do not burn well, making emissions even worse.


© Flickr/Tim Evanson

A flare near a wellhead in North Dakota. In 2014, flaring in North Dakota produced almost 13 million tons of carbon dioxide pollution.

of these processes. These alternative uses for associated gas are all in use today in oil fields in the U.S.[113] Oil companies are utilizing these alternatives not because they have been required to do so—before the new flaring rules were issued in North Dakota this year, the previous regulations were very permissive—but because using these alternatives is profitable.

Note: We have not included estimates of abatement of greenhouse gases or other pollutants from flaring, which were not covered in EPA's white papers, in the pollution abatement totals in this report.

The remaining wells (around 4,600) do not have plunger lifts and emitted about 58,000 tons of methane.

Emissions from high-emitting wells, with and without plunger lifts, can be reduced with low-cost measures. As noted above, plunger lifts and other technologies can all be used to get liquid out of wells efficiently. According to Natural Gas STAR documentation, capital and other startup costs for a relatively routine plunger lift installation can range from $2,600 to $10,400 per well.[121] These simple installations typically reduce venting of natural gas around 70 percent.[122]

Operators of high emitting wells with plunger lifts installed should be required to reduce emissions by at least 80 percent, and operators of high emitting wells without plunger lifts should be required to reduce emissions by at least 90 percent.

More sophisticated "smart" automation systems can reduce emissions even further—one large operator of wells with plunger lifts reduced emissions a further 80 percent using smart automation and proper management,[123] and EPA estimates that these systems reduce emissions over 90 percent compared to emissions without a plunger lift in place.[124] Smart automation systems cost $8,300 to $28,000 per well, for the entire system including the plunger lift, or $5,700–$18,000 per well for the smart automation system alone.[125] Because the gas that would otherwise be wasted is being recovered, the operator will see increased revenue from the sale of that recovered gas.

Indeed, operators derive numerous benefits from use of plunger lifts and other measures to control liquids unloading emissions. Well blow downs involve operational costs in the form of labor costs to perform manual blow downs and workover costs as a result of remediating poor conditions from liquids build-up. Installing plunger lifts will not only reduce these costs, but will also increase the productivity of the well more effectively (and in a more timely manner) than blow-downs.[126] Accordingly, the up-front costs of plunger lifts can be quickly recouped through reduced operational costs associated with blow downs, as well as increased revenue from increased gas production and minimization (or elimination) of wasteful venting.

As a result, plunger lift installations typically have payback periods of 9 months or less.[127] These benefits are all magnified for smart automation systems,[128] and installation of smart automation on a small set of wells with plunger lifts already installed is estimated to have a payback time of 12 months.[129]

As noted above, there are many technologies that can be used to remove liquids from wells that can eliminate or greatly reduce venting; plunger lifts are not the only useful liquids removal technology. It is important to note that, for high emitting wells, other approaches can be used to control emissions, such as blowdown tanks and vapor recovery units to capture gas that would be vented, or, as a last resort, the use of flares. For the small set of wells with emissions of over 300,000 cubic feet a year, these types of controls are appropriate.

Given the proven performance of plunger lifts with smart automation, the availability of other techniques to remove water from wells, and approaches to capture or flare emissions that would otherwise be vented, it is reasonable to require significant abatement of emissions from these high-emitting wells. The availability of smart automation justifies standards requiring reduction of methane emissions from high emitting wells with plunger lifts by 80 percent, and high emitting wells without plunger lifts by 90 percent.

We estimate that such a policy, targeted only at high emitting wells, could reduce nationwide emissions by 120,000 tons of methane per year.

RECOMMENDATION

EPA should require the small portion of gas wells that vent over 300,000 scf/year to reduce methane emissions using plunger lifts with smart automation or other technologies, including control technologies to capture gas that would be emitted or, as a last resort, flare it. Operators of high emitting wells with plunger lifts installed should be required to reduce emissions by at least 80 percent, and operators of high emitting wells without plunger lifts should be required to reduce emissions by at least 90 percent.

ABATEMENT POTENTIAL

An emission standard for wells venting more than 300,000 scf/year during liquids unloading could reduce annual methane emissions by 120,000 tons.

Drilling pipe in Houston, Texas.

© Blake Thornberry/Flickr

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CHAPTER 4

SYNTHESIS

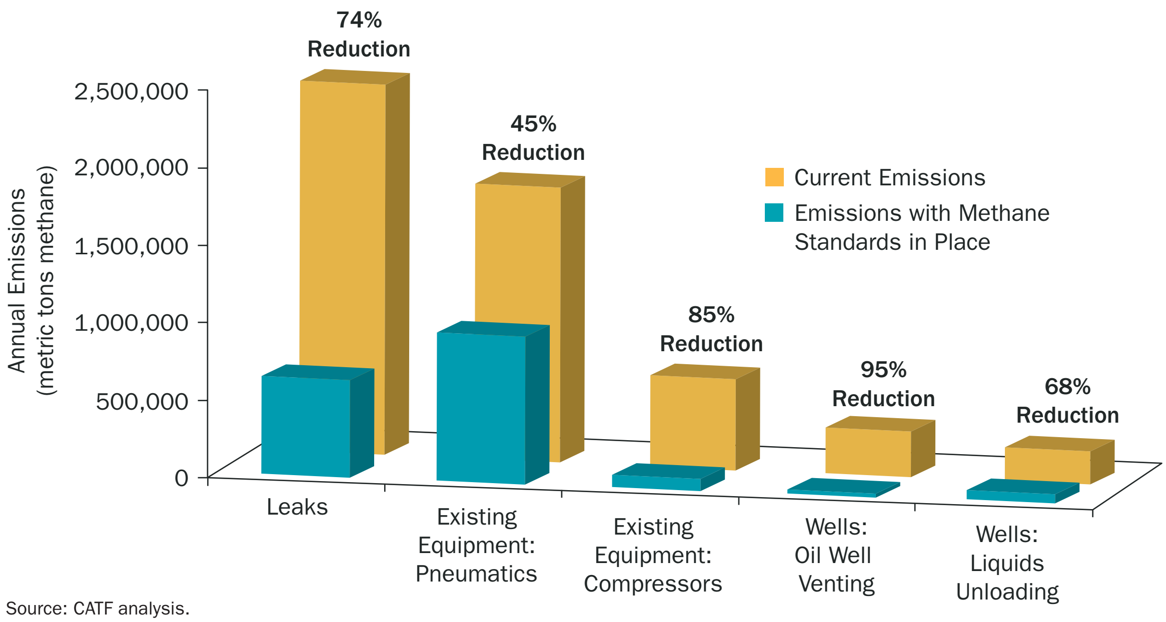
Natural gas drilling rig in Shreveport, Louisiana.

Magnitude of Methane Abatement from the Measures We Recommend

By addressing leaks, outdated equipment, and emissions from wells, the technologies and practices recommended in this report would reduce current emissions from the oil and gas industry by nearly 50 percent (see Figure 5, p. 40). Using bottom-up inventories (principally EPA's U.S. GHG Inventory), we estimate that the potential methane emission reductions from these sources are at least 3.2 to 3.7 million metric tons of methane per year. Reducing methane pollution by this amount will have as much climate benefit, over a 100-year timeframe, as reducing annual carbon dioxide (CO_2) emissions by 115 to 131 million metric tons. The climate benefits in the first 20 years after methane reductions occur would be even larger–equivalent to reducing annual CO_2 emissions by 280 to 320 million metric tons.[130] That's the amount of CO_2 emitted annually by over 62 million passen-ger cars.[131]

As we discuss in Chapter 1, the figures for methane emissions from the oil and gas sector in bottom-up inventories such as those used in our analysis are considerably lower than indicated by "top-down" assessments of emissions from the sector. Methane emissions certainly could be twice as high as EPA estimates, and may be even higher. The measures we recommend in this report are likely to address much of this "extra" methane that is not accounted for in the inventories* (see note, p. 40), as well as much of the methane accounted for in the inventories. Actual abatement could be twice as high as we calculate—over seven million tons of avoided emissions—and perhaps even higher.

FIGURE 5
Significant Methane Reductions are Possible at Sources Identified in this Report



Source: CATF analysis.

The technologies and practices that we identify in this report can reduce methane pollution from the sources we identified, abatement adds up to nearly a half of industry emissions.

Co-Benefits: Reductions of Other Pollutants

All control measures we describe in this report also reduce emissions of other pollutants, including smog-forming VOCs and toxic HAPs that are present to some extent in natural gas in all sectors of the industry, though the relative amount of these other pollutants changes due to gas processing. We used EPA data on the typical ratios of VOC and toxic pollutants to methane in various pollution streams (from wells, processing plants, transmission pipelines, etc.) to estimate the reduction in emissions of these other pollutants from our recommended measures. These reductions in harmful VOCs and HAPs are shown in Table 7, along with the methane abatement estimates.

The climate benefits in the first 20 years after methane reductions occur would be equivalent to reducing annual CO_2 emissions by 280 to 320 million metric tons—the amount of CO_2 emitted annually by more than 62 million passenger cars.

The emission reductions in Table 7 are based solely on the analysis of bottom-up inventories described in Chapter Three of this report, and do not take into account that emissions of VOCs and HAPs from the oil and gas industry are very likely higher than the inventories estimate.

A number of lines of evidence support this conclusion. Several top-down atmospheric measurements have shown higher emissions of VOC and HAP species than bottom-up inventories report. For example, the study by Petron *et al.* reporting higher emissions of methane from the Denver-Julesberg basin in Colorado also reports emissions of benzene *seven* times higher than predicted by the bottom-up inventory maintained by the state of Colorado.[132] Taking a different angle to evaluating the inventories by considering the (small) number of states reporting emissions, EPA's Inspector General recently concluded that EPA's National

* As we discussed in the section on Finding and Fixing Leaks (p. 20), there is compelling evidence that "super-emitters"—uncommon, but very large emitters such as leaks or improper conditions (valves stuck open, etc.)—are important contributors to methane emissions, and may explain a large part of the gap between bottom-up inventories and top-down studies. Leak detection and repair programs will greatly reduce emissions from super-emitters in addition to substantially reducing emissions from routine leaks, so these programs should reduce the "extra" emissions.

TABLE 7

Nationwide Reduction in Annual Methane, VOC, and HAP Emissions from the Measures Described in this Report

	Potential Emissions Reductions (metric tons)		
	Methane	VOC	HAP
Leaks	1,730,000–1,800,000	184,000–204,000	6,750–7,510
Compressors	480,000	41,100	1,480
Pneumatic Equipment	723,000–871,000	199,000–203,000	7,520–7,670
Oil Wells	139,000–382,000	131,000–360,000	4,950–13,600
Liquids Unloading	120,000	17,500	1,270
Total abatement, metric tons	3,190,000–3,650,000	573,000–825,000	21,900–31,500
Total abatement, percentage of current emissions	42–48%	16–23%	11–16%

Source: CATF analysis. VOC and HAP abatement is calculated using methane abatement figures and ratios of methane to VOC and methane to HAP for various pollution streams from supporting documentation for EPA's 2012 standards. See previous chapter for discussion of methane abatement potential and appendix for details and references for methane abatement and details on calculations of VOC and HAP abatement. See appendix for details.

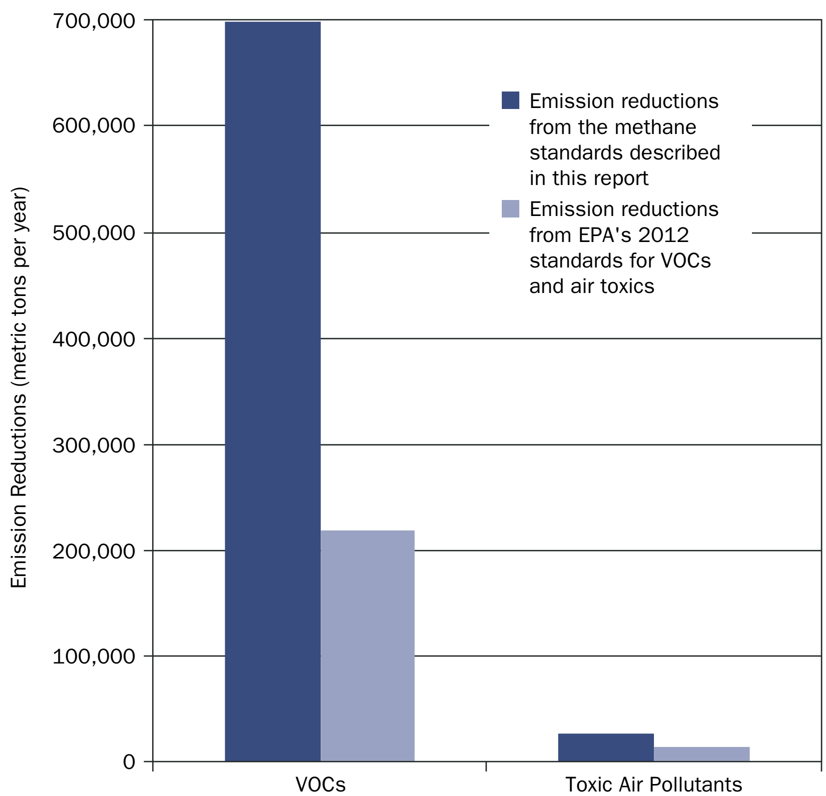
Emissions Inventory "likely underestimates" VOC and HAP emissions from the oil and gas sector.[133] Accordingly, like our estimates of methane abatement based on bottom-up inventories, the figures in Table 7 for VOC and HAP abatement from these measures are likely underestimates. Actual abatement of VOC and HAP could certainly be double these estimates, or even more.

Even using the conservative estimates of VOC and HAP emissions from the bottom-up inventories, the recommended measures would have important benefits for air quality in and downwind of oil and gas producing areas. They would achieve significantly greater reductions in VOCs and HAPs than EPA's 2012 Standards for VOC and air toxic emissions from oil and gas as shown in Figure 6, and would reduce the levels of smog-forming VOCs as much or more than programs directed at ozone reduction, such as gasoline reformulation.

While the measures we recommend in this report are a critical priority for reducing emissions of methane, they are not sufficient to address the health burdens from other air pollutants, and EPA will need to require additional measures to reduce emissions of VOCs and, particularly, HAPs. Along these lines, in 2012 several environmental groups petitioned EPA to strengthen the agency's 2012 standards for toxic emissions from oil and gas sources such as dehydrators and tanks.[134] In 2014, environmental groups also petitioned EPA to issue regulations to reduce HAP emissions from oil and

FIGURE 6

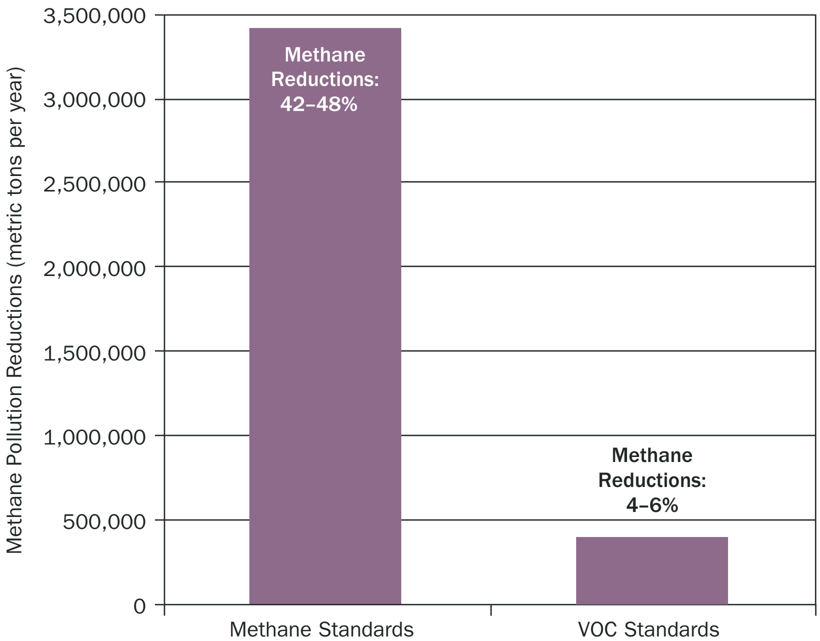
Benefits for VOC and Toxic Air Pollutants Compared to EPA's 2012 Standards



Source: EPA 2012 RIA Tables 3-4, 3-5, 3-9 and CATF analysis.

The direct methane standards we discuss in this report would reduce emissions of VOC and toxic air pollutants considerably more than EPA's 2012 standards for VOCs and air toxics.

FIGURE 7
Methane Reductions from Various Regulatory Approaches



Source: CATF analysis.

Direct methane standards can reduce close to half of oil and gas methane emissions. In contrast, other regulatory approaches would reduce methane emissions far less.

Sand traps at a natural gas well in Washington County, Pennsylvania.

© CATF

natural gas wells.[135] EPA needs to pursue the measures set forth in these petitions, including carrying out a comprehensive evaluation of health risks from all oil and gas sources using the best available current science.

Comparing Approaches to Reducing Methane

In this document we recommend a set of measures to reduce emissions of methane (and other pollutants) from new and existing wells, equipment and facilities in the oil production and natural gas industries. This level of abatement can be achieved if EPA issues new source performance standards for methane emissions from new sources under Section 111(b) of the Clean Air Act, and then, in partnership with the states, addresses existing sources of methane under Section 111(d) of the Act.

Under the Administration's "Strategy to Reduce Methane Emissions," EPA is considering whether to address methane pollution from the oil and gas sector by setting such methane standards. An alternative policy under consideration is adopting additional VOC standards; the Methane Strategy also notes that EPA will continue to work with industry to expand voluntary programs. Setting aside the legality of pursuing either of these paths in lieu of methane standards, the alternate approaches would reduce methane emissions far less, and in a less certain manner, than direct methane standards, as we discuss below.

VOC STANDARDS

EPA is considering expanding the coverage of the 2012 NSPS standards by setting standards for new and modified sources of VOC pollution in the oil and gas sector that are currently unregulated, including oil wells and liquids unloading. In addition, EPA can issue guidelines for state regulation of *existing* sources of VOC pollution in areas where ozone concentrations violate national health standards. Section 182 of the Clean Air Act provides the authority for EPA to issue such guidelines, called "control techniques guidelines" (CTGs). If EPA were to use CTGs to regulate VOC emissions from existing compressors, pneumatic controllers, wells and leaking equipment, some methane reductions would be expected (though not ensured)* from these sources.

* If EPA issues VOC standards instead of methane standards, facility owners would only be required to reduce VOC emissions. While we expect that owners would adopt technologies that reduce both methane and VOC, a future technology may selectively reduce VOC (allowing methane emissions without abatement), perhaps at lower cost than current technologies. For example, some systems use an absorbent to remove VOC from an emission stream; typically the absorbent does not remove methane from the emissions stream. In such cases, if only VOC emissions were regulated, it would not be possible to enforce or ensure methane reductions.

TABLE 8
Comparison of Pollutant Reductions Achieved by Methane and VOC Standards from the Sources Described in this Report

Approach	Emissions Reductions (metric tons/yr)		
	Methane	VOC	HAP
Methane Standards for new and existing sources, as described in this report	3,190,000–3,650,000	573,000–825,000	21,900–31,500
VOC Standards (new and modified production and processing sources, and existing production and processing sources in areas with excessive ozone)	329,000–484,000	136,000–279,000	5,760–11,100

Source: CATF analysis.

We estimate the potential reductions of methane pollution that EPA could achieve as a co-benefit by regulating VOC emissions from these sources in the following manner. We start with national emission estimates for oil well completions and liquids unloading from the analysis provided in Chapter 3 of this report, as the significant amount of VOC pollution from these two sources makes them clear candidates for VOC standards under Section 111. To this value we then add an estimate of the nationwide methane abatement that could be achieved by issuing CTGs for VOCs from oil and gas production and gas processing. We estimate that 9 percent, 7 percent, and 8 percent of gas production, oil production, and gas processing, respectively, occurs in areas exceeding national ozone standards, and hence where CTGs could apply.[136]

Using this approach we estimate that if EPA sets standards requiring VOC abatement from oil well completions and liquids unloading nationwide, and guidelines requiring VOC abatement from other production and processing sources in areas with excess ozone, nationwide annual methane emissions could be reduced by 327,000–484,000 metric tons, or only about 10 to 13 percent of the emissions reductions that EPA could achieve with direct methane standards (see Figure 7, p. 42).

Standards for methane would reduce VOC emissions more than additional standards for VOCs (beyond EPA's 2012 standards), as shown in Table 8, because methane standards would require cleanup of more pollution sources than new VOC standards.[137]

VOLUNTARY PROGRAMS

EPA also is considering pursuing methane reductions through voluntary programs instead of mandatory standards. For example, EPA's Natural Gas Star program has demonstrated the feasibility and cost of several technologies and strategies for methane. Voluntary programs have slowly reduced emissions somewhat over the last decades, although reductions reported to the Natural Gas Star program have decreased in recent years.[138] While some companies have taken steps to control their methane pollution, adoption of the technologies promoted by Gas Star has proven slow, despite low costs and demonstrated effectiveness at keeping gas in the system and thus reducing emissions. The technologies are still seen as among the "best" practices, not "standard" practice, by most operators.

Like setting standards for VOCs, voluntary programs are likely to achieve only modest reductions of methane that would fall well short of our country's climate goals. Voluntary programs by definition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Solar powered pumps at a natural gas production facility in Washington County, Pennsylvania.

A flare near a wellhead in North Dakota.

cannot deliver permanent, enforceable, verifiable emission reductions. Further, not all gas producers, processors, transmission pipeline companies, and distributors will choose to participate in voluntary programs, potentially leaving the worst methane offenders uncontrolled. Because of the super-emitter phenomenon, the emissions from such non-participants could be outsized and the environmental consequences severe. A voluntary approach will always allow some companies to pollute excessively and potentially create air pollution hotspots. Since the Gas Star program has been actively engaging industry for some years, the operators inclined to adopt best practices have probably already done so. Further substantial reductions are not likely. Industry-wide mandatory standards are needed to ensure rapid, consistent adoption of the sensible reduction measures discussed in this report, and reduce emissions enough to achieve our country's climate commitments.

For example, a single gas producer is currently venting several billion cubic feet of natural gas per year during liquids unloading from their wells in the San Juan basin in New Mexico and Colorado —accounting for over 95 percent of all liquids unloading emissions from the basin reported to EPA's Greenhouse Gas Reporting Program.[139] As detailed in Chapter 3, technologies have been available to greatly reduce liquids unloading venting for many years, but as this example shows, some operators will fail to adopt these technologies nonetheless, absent nationwide standards.

Without the type of monitoring and inspection programs required to demonstrate compliance with enforceable emission standards, it is not clear that the reductions claimed from voluntary programs can be adequately verified. In contrast, the approach we describe here—direct methane standards for new and existing equipment—would deliver permanent, verifiable, enforceable reductions in just a few years. As this analysis shows, the most effective way to reduce methane pollution from the oil and gas sector is for EPA to issue national emission standards for methane from new and modified sources, and state-implemented guidelines for methane from existing sources under Section 111 of the Clean Air Act.

Costs of These Measures

The costs of implementing the emission reduction technologies and practices we recommend throughout the oil and gas industries are very low. For many of the technologies and practices that we discuss, the net cost is negative, that is, the value of the saved gas exceeds the value of the new equipment or maintenance. These "net savings" technologies include compressors at gas processing plants and the replacement of high-bleed pneumatic controllers with low-bleed devices. Taken together, the average abatement cost of this entire set of measures is only $8 to $18 per metric ton of carbon dioxide equivalent.* These measures would cost the industry just 4 to 9 cents per Mcf of gas sold, which is less than 1 percent of the average price paid by residential consumers.** And the annual costs of implementing

* This is calculated using a 100-year GWP for methane of 36, as recommended by IPCC's AR5.

** ICF International's 2014 analysis of the cost of methane abatement measures from oil and gas sources reports that a similar, but not identical, set of abatement measures could reduce methane from oil and gas by 40% with a lower net abatement cost (equivalent to 1¢ per Mcf of gas sold). The analysis carried out for this report and the ICF report is quite consistent; the lower costs of the ICF report largely reflect the lower stringency of the measures that ICF focused on. In particular, ICF only considered quarterly LDAR inspections, while this report considers more frequent LDAR at a number of facilities (see Table 2, p. 23).

Oil well and flare in the Permian Basin in New Mexico.

these technologies and practices is less than 1 percent of the investments in increased capacity that the oil and gas industry made in the U.S. in 2013.[140] They are less than 1.6 percent of the revenue from natural gas sales in the U.S., and less than 0.6 percent of the combined revenue from the sale of crude oil and natural gas produced in the US.[141]

Moreover, the cost of these measures is far outweighed by the climate benefits and other benefits to public health and well-being. The "social cost" is an estimate of the costs society avoids from climate change-related damages by reducing greenhouse gas pollution. Such costs include, but are not limited to, climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change.[142] Using the methodology and parameters used by the United States Office of Management and Budget to calculate the central estimate of the social cost of carbon dioxide,[143] EPA economists have calculated that the estimated social cost of a ton of methane emitted in 2015 is $970.[144]

We conservatively estimate that the measures we recommend in this report would reduce methane emissions for $290 to $660 per ton of methane —well below the central estimate of the social cost of methane. Moreover, as the Chapter 1 notes, our approach overestimates the cost-per-ton of these measures, since real emissions are very likely higher than was assumed when preparing the cost estimates we used. It is also critical to consider that these measures would substantially reduce emissions of VOC and toxic air pollutants in addition to methane, further reducing communities' health burdens and the high costs associated with them. In short, these measures will cost far less than the damage from the pollution that they will prevent.

The technologies we highlight in this report are affordable, proven, and feasible. They can be very rapidly deployed. Regulating methane pollution from the oil and gas industry is a low-cost way to greatly reduce air pollution that is rapidly warming our climate and degrading local air quality. EPA should seize the opportunity to clean up these emissions and capture gas that would otherwise be wastefully leaked and released into our air.

ENDNOTES

1 These ratios are global warming potentials (GWPs) and are taken from IPCC's most recent Fifth Assessment Report. See IPCC, Climate Change 2013: The Physical Science Basis (Sept. 2013), Chapter 8, page 714, Table 8.7, available at *https://www.ipcc.ch/report/ar5/wg1*. IPCC notes that the GWP of methane from fossil fuel sources (like natural gas and coal) is slightly higher than from other sources, like agriculture. See notes to Table 8.7. EPA and other US Government reports of climate pollutant emissions generally use lower GWPs from older IPCC Reports.

2 Calculated with US EPA's Greenhouse Gas Equivalencies Calculator (*http://www.epa.gov/cleanenergy/energy-resources/calculator.html*) and data from the U.S. Energy Information Administration (EIA) on gasoline consumption (see *http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm*), and using a 20-year GWP of 87 for methane.

3 Brown, H.P, (2011), "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking," available at *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.*

4 See *http://www.epa.gov/oaqps001/community/details/oil-gas_addl_info.html#activity2.*

5 See *http://naturalgas.org/naturalgas/processing-ng.*

6 Beyond the emissions directly associated with natural gas emissions, engines and flares located at oil and gas sites emit other pollutants, including particulate matter, toxic compounds, and VOC and other species that create ozone. This report does not focus on these combustion pollutants.

7 Field, R. A. et al. (2014) "Air quality concerns of unconventional oil and natural gas production." Environmental Science: Processes & Impacts, Vol. 15, 954-969, doi: 10.1039/C4EM00081A. Available at: *http://pubs.rsc.org/en/content/articlelanding/2014/em/c4em00081a#!divAbstract.*

8 Edwards, P. M., et al., (2013) "Ozone photochemistry in an oil and natural gas extraction region during winter: simulations of a snow-free season in the Uintah Basin, Utah." Atmos. Chem. Phys., 13, 8955, doi:10.5194/acp-13-8955-2013. Available at *www.atmos-chem-phys.net/13/8955/2013.*

9 Adgate, J.L., B.D. Goldstein, and L.M. McKenzie (2014) "Potential Public Health Hazards, Exposures and Health Effects from Unconventional Natural Gas Development." Environ. Sci. Technol., 48, 8307. DOI: 10.1021/es404621d. Available at: *http://pubs.acs.org/doi/abs/10.1021/es404621d.*

10 Calculated using emission data from EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012 (April 2014). Available at *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.* Referred to as "EPA GHG Inventory" in references below. We assume that gas from production and processing is 79% methane by volume, and methane from transmission and distribution is 93% methane by volume. The number of homes that could be heated with this amount of gas is based on figures for residential consumption of gas, and the number of residential gas consumers, from EIA. See *http://www.eia.gov/naturalgas/data.cfm#consumption.*

11 Using the 20-year GWP for methane of 87 (see endnote 1 above) and EPA's Greenhouse Gas Equivalencies Calculator.

12 See *http://epa.gov/otaq/climate/regulations.htm* for a description of regulations to reduce GHG emissions from vehicles and *http://www2.epa.gov/carbon-pollution-standards* for a description of the proposed rule for CO_2 from power plants.

13 Y. Xiao et al. (2008) "Global budget of ethane and regional constraints on U.S. sources." J. Geophys. Res. 113, D21306, available online at: *http://onlinelibrary.wiley.com/doi/10.1029/2007JD009415/abstract*. Their result was based on a 2008 edition of the US GHG Inventory; the latest edition estimates that 2004 emissions were 17% higher than the 2008 edition estimated, a small difference compared to the 50–100% difference reported by this paper.

14 S. Miller et al. (2013), "Anthropogenic emissions of methane in the United States," Proc. Natl. Acad. Sci. (USA) 110, 20018. Available at *http://www.pnas.org/content/110/50/20018*.

15 Karion, A., et al. (2013) "Methane emissions estimate from airborne measurements over a western United States natural gas field." Geophysical Research Letters, Vol. 40, 4393-4397, doi:10.1002/grl.50811. Available at: *http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/full.*

16 According to the Inventory estimates, oil and gas production and gas processing (the main segments of the natural gas supply chain present in these basins) emit a little less than 1% of the methane that was withdrawn from underground formations in 2012.

17 Top-down studies conducted at the regional scale in the southwest US, or at the nationwide scale, report leak rates that are below 6%. These studies are summarized in Brandt, A.R., et al. (2014) "Methane Leaks from North American Natural Gas Systems," Science, 343, 733. Available online at: *https://www.sciencemag.org/content/343/6172/733.*

18 See, for example, the variation between basins in reported volumes of gas that is wasted (vented or flared) in United States Government Accountability Office (2010), Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases. Report GAO-11-34, Appendix III. Available at: *http://www.gao.gov/assets/320/311826.pdf.*

19 Brandt, A.R., et al. (2014).

20 See reference 7 above.

21 These include incomplete burning of methane in engines powered by natural gas and upsets (release of gas into the air due to malfunctions, etc.).

22 EPA's authority to regulate greenhouse gases was further solidified by the Supreme Court this summer in UARG v. EPA. In reviewing EPA's interpretation of the Prevention of Significant Deterioration program under the Clean Air Act, the Court recognized that EPA's decision to require large sources to apply the best available control technology (BACT) to control pollutants "subject to regulation" under the Act, including greenhouse gases, was permissible.

23 US Environmental Protection Agency (EPA). (2012) Regulatory Impact Statement, Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. April 2012. Tables 3.4 and 3.5. Available at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.* Referred to as "US EPA Regulatory Impact Statement" below.

24 See Section 111(d) of the CAA (42 U.S.C. 7411(d)(1); 40 C.F.R. § 60.21(a)); see also 42 U.S.C. 7411(a)(2) (defining the term "new source" to include modified sources).

25 ICF International. (2014) "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," p. 1-1. Available at: *http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.*

26 See Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490, 49,516 (Aug. 16, 2012).

27 See 77 Fed. Reg. 49,513.

28 US EPA. White Papers on Methane and VOC Emissions. April 2014. Available at: *http://www.epa.gov/airquality/oilandgas/whitepapers.html.* Sierra Club, Natural Resources Defense Council, Clean Air Task Force, and Earthworks comments on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector, June 16, 2014. Available at: *http://www.regulations. gov/#!documentDetail;D=EPA-HQ-OAR-2014-0557-0041.*

29 Includes fugitive emissions reported in US GHG Inventory and a portion of emissions that can be attributed to static components of the compressor (based on memos cited by EPA in US GHG Inventory). For the distribution segment, it includes leaks from large aboveground distribution facilities. See appendix for more details.

30 Emissions from the seals for moving parts on compressors are discussed in the Compressor Seal section—these are not categorized as "leaks" for the purpose of methane emissions from oil and gas.

31 The estimate used here (2.4 million metric tons of methane per year) does not include leaks from gathering, transmission, or distribution pipelines per se.

32 Brandt, A. R., et al. (2014), at 734; R.A. Alvarez et al. (2012), "Greater focus needed on methane leakage from natural gas infrastructure," Proc. Natl. Acad. Sci. (USA) 109, 6435, at 6437. Available at *www.pnas.org/content/109/17/6435.*

33 Calculated from data in Tables 1 and 7 of: National Gas Machinery Laboratory, Clearstone Engineering, Innovative Environmental Solutions, (2006) Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites (EPA, 2006). Available at: *http://www.epa.gov/gasstar/tools/related.html#four.*

34 See 5 C.C.R. § 1001-9 XVII.F (2014). Available at: *https://www.colorado.gov/pacific/sites/default/files/063_R7-REG-Excerpt-request-11-21-13-19-pgs-063_1.pdf.*

35 Pennsylvania exempts operators from acquiring air emission permits for new unconventional wellpads, provided they perform annual instrument-based LDAR surveys. See: Department Of Environmental Protection, Air Quality Permit Exemptions, Category No. 38. Available at *http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.* Pennsylvania's general permit for natural gas gathering compressor stations and processing plants requires quarterly instrument-based LDAR surveys for new and existing facilities. See: Department Of Environmental Protection, General Operating Permit 5, Section H, available at *http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/GP-5_2-25-2013.pdf.*

36 Quarterly instrument-based LDAR is required in the Upper Green River Basin for new and modified facilities. See Wyoming Department of Environmental Quality (WDEQ) (2013), Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance at 22 and 27. Available at: *http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Guidance%20Documents/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.*

37 Ohio General Permit 12 for oil and gas production sites requires quarterly instrument-based LDAR, although it contains provisions for less frequent LDAR for facilities with manageable leak frequencies (if less than 2% of components are leaking, the next survey can be skipped). See Ohio General Permit 12.1(C)(5)(c)(2). Available at: *http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx*. We do not support these "step-down" provisions in LDAR rules as they incentivize operators to not find leaks, increase the complexity of the rule and compliance efforts, and the record shows that facilities can have leak frequencies below 2% and still waste copious amounts of natural gas. See Sierra Club, et al., Rebuttal Prehearing Statement for Colorado Oil and Gas 2014 Rulemaking at 8–11. Available at: *ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB.pdf.*

38 Colorado Department of Public Health and Environment, Cost-Benefit Analysis, Submitted Per § 24-4-103(2.5), C.R.S. p. 27. Available at: *ftp://ft.dphe.state.co.us/apc/AQCC/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf.* Referred to as "CDPHE Cost-Benefit Analysis" below.

39 Carbon Limits is an independent consultancy experienced in climate change policies and emission reduction project identification and development, particularly in the oil and gas sector.

40 Carbon Limits, Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (2014), Table 6. Available at: *http://www.catf.us/resources/publications/view/198*.

41 Calculated from data in Table 27 of CDPHE Cost-Benefit Analysis.

42 Noble Energy. Colorado Air Quality Control Commission Hearing Proposed Revisions to Regulation 7 Testimony. 2/21/2014. Available at: *ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/Noble.pdf*, and Anadarko Petroleum Corporation. "Regulations 3, 6 & 7. Colorado Air Quality Control Commission Hearing Testimony." 2/21/2014. Available at: *ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/Anadarko.pdf.*

43 Jordan, Doug. "SWN Gas Capture Case Study and Methane Emission Initiatives." Natural Gas STAR Annual Implementation Workshop, San Antonio, 13 May 2014, slide 29. Available at: *http://www.epa.gov/gasstar/documents/workshops/2014_AIW/Gas_Capture.pdf.*

44 Carbon Limits (2014) at 16. Carbon Limits found that the net present value (NPV) of repairs was positive for the vast majority of leaks and leak volume. Using a value of $4/Mcf for recovered gas, they found that 97 percent of leaking gas comes from leaks that have a positive repair NPV.

45 Calculated from data in Table 30 of CDPHE Cost-Benefit Analysis.

46 Allen, Cindy, "CDPHE 2014 Rulemaking—Encana Rebuttal," 22 February 2014, available at: *ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Encana%20Oil%20&%20Gas%20USA%20%28Encana%29/Encana%20REB%20Presentation.pdf.*

47 CDPHE Cost-Benefit Analysis, Table 35.

48 The CDPHE Cost-Benefit Analysis reports net abatement costs of $474 and $805 per ton of methane *and* ethane assuming a $3.5/Mcf value of saved gas, see Tables 33 and 35. We recalculated using a $4/Mcf value of saved gas and then converted this to cost per ton of methane abatement assuming that natural gas at production facilities has a ratio of methane to ethane of 6.2 by weight, in keeping with EPA documentation for the 2012 standards. See Brown, H.P, (2011), "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking." Available at: *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.*

49 Calculated from data in Table 3-4 of ICF International (2014).

50 40 C.F.R. §§ 60.632(f) (Subpart KKK), 60.5400(f) (Subpart OOOO).

51 For example, operators must inspect pollution control equipment on some new tanks and centrifugal compressors—those subject to EPA's 2012 standards for Oil and Gas for leaks and repair them. See 40 CFR §60.5416. Also, some equipment that handles high concentrations of toxic air pollutants at gas processing plants is subject to LDAR rules, even if the equipment was in place before 1984. See 40 CFR § 63.769.

52 US GHG Inventory, Annex 3, Table A-130.

53 For example, recent explosions due to outdated natural gas distribution pipes have occurred in Birmingham, AL, and Allentown, PA. Both explosions were deadly. See Reed, J. "Investigators suspect leak in natural gas distribution line in deadly Gate City apartment explosion." AL.com, Dec. 28, 2013, available at: *http://blog.al.com/spotnews/2013/12/investigators_suspect_leak_in.html* and McEvoy, C. "Allentown gas explosion caused by pipe recommended for replacement 30 years earlier." Lehigh Valley Live, June 12, 2012. Available at: *http://www.lehighvalleylive.com/allentown/index.ssf/2012/06/pipe_that_caused_allentown_gas.html.*

54 Based on extrapolation from data in USGHGI Annex 3. Because the rates of replacement of outdated mains and services vary widely between states, simple extrapolation of current national rates of pipeline replacement is not likely to be accurate. Some states have recently accelerated the rate of pipeline replacement, while other states would take many decades to replace all outdated pipelines (particularly unprotected steel mains). Despite these caveats, the nationwide rate of replacement of outdated pipeline is well below 5% per year, so it is expected to take decades to replace outdate pipelines currently in place, absent policy changes.

55 US EPA. Lessons Learned from Natural Gas STAR Partners, Options For Reducing Methane Emissions

56 From Pneumatic Devices In The Natural Gas Industry," hereafter "Lessons Learned – Pneumatic Devices,"p. 2. Available at: *http://epa.gov/gasstar/documents/ll_pneumatics.pdf.* See Technical Appendix for a description of estimation methodology.

57 Lessons Learned—Pneumatic Devices, p. 2.

57 Lessons Learned—Pneumatic Devices.

58 High-(continuous) bleed controllers may only be newly installed at production facilities "based on functional needs, including but not limited to response time, safety and positive actuation." (40 C.F.R. § 60.5390(a)). At processing plants, controllers that continuously bleed any amount can only be used based on the exception above. See 40 C.F.R. § 60.5365(d)(3) and § 60.5390(b)(1). (There are relatively few existing pneumatic controllers that bleed natural gas in processing.)

59 40 C.F.R. §60.5390(c)(1).

60 Colorado's rulemaking analysis assumed a 15 year lifetime for pneumatic controllers. See CDPHE Cost-Benefit Analysis, Table 39. No data was submitted in the rulemaking process suggesting shorter lifetimes. Rebuild kits are available and many operators will keep high-bleed controllers operating for many years, perhaps far longer than 15 years.

61 See 5 C.C.R. § 1001-9 XVIII (2009). Available at: *https://www.sos.state.co.us/CCR/GenerateRuleps.pdf.do?ruleVersionId=2772&fileName=5%20CCR%201001-9.*

62 5 C.C.R. § 1001-9 XVIII.C.2.b (2014).

63 5 C.C.R. § 1001-9 XVIII.C.3 (2009).

64 Email from Daniel Bon, CDPHE, to David McCabe, Clean Air Task Force, 1 November 2013.

65 Colorado estimated that the 2009 standard would reduce daily VOC emissions by 23.3 short tons (or 7,700 metric tons per year), see Colorado Department of Public Health and Environment (2008), *Denver Metropolitan Area and North Front Range 8-Hour Ozone State Implementation Plan: Technical Support Document For Proposed Pneumatic Controller Regulation* at 5. Available at: *http://www.colorado.gov/airquality/documents/deno308/Pneumatic_Controller_TSD_DRAFT.pdf.* This corresponds to a methane reduction of about 7,600 metric tons, based on the ratio of VOC reductions to methane/ethane reductions reported by CDPHE for the 2014 rules for pneumatic controllers (see CDPHE Cost-Benefit Analysis at 32) and typical ratios of methane to ethane (see endnote 41 above). These levels of abatement are confirmed by data from the Greenhouse Gas Reporting Program that shows that oil and gas producers in Rocky Mountain oil and gas basins with similar numbers of wells, where replacement of high-bleed controllers has not been required, emitted amounts ranging from 5,000 tons of methane (in the Piceance basin) to over 37,000 tons (in the San Juan basin). In contrast, only a little over 1,000 tons was emitted from the Denver basin (which extends beyond the region in Colorado where the 2009 rules applied).

66 In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. See API, "Technical Review of Pneumatic Controllers," at 7 (Oct. 10, 2011).

67 WDEQ (2013), at 11. This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers (email from Mark Smith, WDEQ, to David McCabe, 22 September 2014).

68 WDEQ at 10.

69 ICF International (2014), p. B-6.

70 CDPHE Cost-Benefit Analysis, p. 32.

71 ICF International (2014), p. 3-16.

72 USEPA, "Lessons Learned from Natural Gas STAR Partners, Installing Vapor Recovery Units on Storage Tanks." Pg. 1. Available at: *http://epa.gov/gasstar/documents/ll_final_vap.pdf.*

73 Calculated with the assumption that emissions from oil tanks and condensate tanks without control devices can be reduced by 95%.

74 40 C.F.R. § 60.5395(e)(1).

75 We are not aware of a single estimate for the number of storage tanks used by the industry nationwide that are not subject to emissions controls, but it is certainly in the hundreds of thousands. For example, EPA estimated in 2012 that there are around 520,000 oil storage tanks, nationwide. See US Environmental Protection Agency (EPA). Technical Support Document, Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. April 2012, Table 7-3. Available at: *http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.* (Referred to as "EPA Technical Support Document (2012)" below). The same table notes estimates that there are about 59,000 condensate tanks nationwide, but this number is probably considerably too low. Colorado estimates that there are 8,080 condensate tanks which would have uncontrolled VOC emissions over six tons per year in Colorado (see CDPHE Cost-Benefit Analysis, Table 2), and Colorado only produces about 3% of US Condensate, according to EIA (see *http://www.eia.gov/dnav/ng/ng_prod_lc_s1_a.htm*). Only a portion of these tanks will be subject to EPA's 2012 rules or other Federal, state, or local air pollution regulations.

76 Calculations based on the US GHG Inventory and ratios of VOC to methane and toxic air pollutants to methane from various emission streams from US EPA Regulatory Impact Statement.

77 Calculated from data in US EPA Regulatory Impact Statement (2012), Table 3-4.

78 Calculated from ICF International. (2014), Tables 3-7 and 4.1.

79 Includes a portion of compressor emissions reported in US GHG Inventory Annex 3, to reflect compressor seal emissions, based on memos cited by EPA in the US GHG Inventory. See appendix for more details.

80 40 C.F.R. § 60.5385(a).

81 79 Fed. Reg. 41,752, 41,766 (July 17, 2014) (Proposed 40 C.F.R. § 60.5385(a)(3)).

82 40 C.F.R. § 60.5365(c) (NSPS applies only to compressors between the wellhead and the point of custody transfer to the transmission and storage segment that were installed after August 23, 2011).

83 EPA GHG Inventory, Annex 3, Table A-128. Available at: *http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf.* Calculated from 51,370 standard cubic feet per day.

84 For a description of the dry seals technology, see USEPA, Lessons Learned from Natural Gas STAR Partners: Replacing Wet Seals With Dry Seals In Centrifugal Compressors (2006). Available at: *http://epa.gov/gasstar/documents/ll_wetseals.pdf.*

85 40 C.F.R. § 60.5365(b).

86 5 C.C.R. 1001-9 § XVII.B.3 (2014).

87 Calculated from data from EPA, Technical Support Document for Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry (July 2011) at Table 6.2, 6.6, and 6.7. Available at: *http://epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.* See Technical Appendix for more details.

88 See cost calculations in Technical Appendix.

89 See 77 Fed. Reg. 49,524.

90 Calculations based on the US GHG Inventory and the ratio of toxic air pollutants to methane from various emission streams from US EPA Regulatory Impact Statement.

91 5 C.C.R. 1001-9 § XVII.D (2014).

92 Id. § XVII.D.4.

93 Id. § XVII.D.3.

94 CDPHE Cost-Benefit Analysis at 34–35.

95 See USEPA, "Lessons Learned from Natural Gas STAR Partners, Optimize Glycol Circulation And Install Flash Tank Separators In Glycol Dehydrators." Available at: *http://epa.gov/gasstar/documents/ll_flashtanks3.pdf.*

96 When a well (gas or oil) is hydraulically fractured, large volumes of water and other substances are pumped down the well to break up (fracture) the rock holding the gas/oil. After fracturing is completed, the water is allowed to flow back to the surface during the "flowback" phase of well completion. Methane from the fractured rock mixes in with this water, and if not controlled, will be vented into the air.

97 40 C.F.R. § 60.5375(a)(1)-(4). EPA recently proposed to clarify that it is practicable to capture natural gas after the "initial flowback phase" when there is insufficient gas in the flowback to operate a separator. *See* 79 Fed. Reg. 41,752, 41,766, 41,768 (July 17, 2014). However, this proposal has not been finalized as of the date of this publication.. Gas wells exempt from this requirement, such as exploration, delineation, and low-pressure wells, similarly must flare the gas instead of venting it. Id. § 60.5375(f).

98 Id.

99 Id. § 60.5365(a) (each gas well is subject to this subpart); § 60.5430 (defining "gas well" as "an onshore well drilled principally for production of natural gas").

100 Environmental Defense Fund (2014), "Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses," *http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf,* p. 9.

101 Id., Table 3. As noted, this data is from the GHG Reporting Program. Producers are not required or expected to report emissions from oil well completions. Despite the gap in the reporting rules, based on a number of indications (such as the formations and pools being produced), we conclude that some operators are reporting emissions for oil well completions (these are reported as gas well completion emissions).

102 Id. at 9.

103 EPA Technical Support Document (2012), Section 5.1.

104 Allen, D., et al (2013). As noted by Environmental Defense Fund (2014), several of the well completions studied by Allen et al. were “co-producing wells” where oil makes up 45–88% of the value of the hydrocarbons the well produced and would those be considered oil wells. REC reduced methane emissions from these wells by over 98%.

105 ICF International calculated that flaring gas during oil well completion after hydraulic fracturing would cost $1.86 per Mcf of avoided venting (see ICF International (2014), p. 3–22.), or $110 per metric ton of avoided methane emissions. Hydraulically fractured oil wells produce large amounts of natural gas, and oil producers generally plan to connect oil wells up to gas gathering pipelines. Capturing gas from REC and directing it to pipelines requires that pipelines be completed before wells are completed, but does not impose any significant costs beyond the costs (principally the costs of separating gas from water with separators) of flaring gas. However, capturing gas creates additional revenue, which more than offsets the cost of the REC equipment, leading to negative abatement costs.

106 Based on data from the US Energy Information Administration, *http://www.eia.gov/naturalgas/data.cfm*.

107 Data from GHG Reporting Program (downloaded from the Envirofacts website). Although the reported emissions for 2013 (the most recent year available) are at the low end of this range (51,000 tons), it is not clear that emissions are this low or that there is any trend in the amount being vented. Reported emissions for this category have been revised substantially (for example, the 2012 emissions were revised upward by ~100 perecent in recent weeks). Therefore the range of emissions currently reported for 2011–2013 are the best estimate of current emissions.

108 ICF International calculated that flaring gas during oil production would cost $0.26 per Mcf of avoided venting (see ICF International (2014), p. 3–22), or $15 per metric ton of avoided methane emissions.

109 EPA Technical Support Document (2012), p. 5-3.

110 Calculated with flaring data from North Dakota Industrial Commission (*https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp*) for August 2013–July 2014. We compared the volume of gas burned over that one year period to EIA data for residential gas consumption by state (see *http://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcf_a.htm*). CO_2 emissions are based on the conservative assumption that gas is 80% methane and calculating carbon content from a standard composition. (Carbon composition is probably actually higher). CO_2 emissions were compared to coal-fired power plant emissions using US EPA’s Greenhouse Gas Equivalencies Calculator.

111 See North Dakota Industrial Commission Order No. 24665 (July 1, 2014). Available at: *https://www.dmr.nd.gov/oilgas/or24665.pdf*. 90% is the highest concrete utilization standard (see Finding 15). Only gas produced after three months of production is factored into the calculation of a firm’s utilization percentage, see paragraph 4 of the Order (page 5).

112 For example, see L. Richards and C. Finch, “Salem Unit Casinghead Gas Project,” Natural Gas STAR Annual Implementation Workshop, Denver, 11 April 2012. Available at: *http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/finch.pdf*.

113 The use of these technologies is documented in a number of news articles. For a discussion of power generation and the use of natural gas compressed on site for truck fuel, see Lee, M., (15 Sept. 2014), “Companies see gold rush in N.D.’s wasted gas,” *Energywire*, *http://www.eenews.net/energywire/2014/09/15/stories/1060005750*. For a discussion of methanol generation, see CBS Detroit, (2 Sept. 2013), “GasTechno Says Methane-To-Methanol Plant Launch A Success,” *http://detroit.cbslocal.com/2013/09/02/gastechno-says-methane-to-methanol-plant-launch-a-success*. NGL recovery (and CNG trucking) are discussed in Krauss, C. (17. Dec. 2013), “Applying Creativity to a Byproduct of Oil Drilling,” *New York Times, http://www.nytimes.com/2013/12/18/business/energy-environment/applying-creativity-to-a-byproduct-of-oil-drilling-in-north-dakota.html?ref=cliffordkrauss&_r=0*. These technologies, and their applicability to the shale oil wells where flaring has become common in recent years, will be discussed in a report that Carbon Limits will issue in Fall 2014.

114 Data from GHG Reporting Program. Only larger operators (those emitting more than 25,000 tons of carbon dioxide equivalent per year) report emissions to this program, so the underestimate is clear. However, it may be particularly severe for liquids unloading. Liquids unloading practices, and emissions, vary tremendously among operators.

115 See USEPA, Lessons Learned from Natural Gas STAR Partners, Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.” Referred to as “Lessons Learned—Options” below. Available at: *http://www.epa.gov/gasstar/documents/ll_options.pdf*.

116 See USEPA, Lessons Learned from Natural Gas STAR Partners, Installing Plunger Lift Systems in Gas Wells,” p. 1. Referred to as “Lessons Learned—Plunger Lifts” below. Available at: *http://epa.gov/gasstar/documents/ll_plungerlift.pdf*.

117 Lessons Learned—Options, p. 5.

118 U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards., (2014) “Oil and Natural Gas Sector Liquids Unloading Processes.” Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel. Available at: *http://www.epa.gov/airquality/oilandgas/2014papers/20140415liquids.pdf*.

119 See 5 C.C.R. § 1001-9 XVII.H, and WDEQ (2013), at 11.

120 Data from GHG Reporting Program.

121 Lessons Learned—Plunger Lifts, pp. 3–4.

122 Calculated from Lessons Learned—Plunger Lifts, Ex. 14.

123 Desaulniers, GP, “Plunger Well Vent Reduction Project.” 13th Annual Natural Gas STAR Implementation Workshop, 24 October 2006, Houston, TX. *http://www.epa.gov/gasstar/documents/desaulniers.pdf*.

124 Lessons Learned—Options, p. 5.

125 Lessons Learned—Options, Exhibit 9.

126 Lessons Learned—Plunger Lifts, p. 9.

127 Lessons Learned—Plunger Lifts, p. 1.

128 Lessons Learnet—Options, Exhibit 9.

129 Lessons Learnet—Options, Exhibit 11.

130 CO_2 equivalent figures calculated using global warming potentials for fossil methane from IPCC’s Fifth Assement Report (100-year GWP of 36; 20-year GWP of 87).

131 Calculated with US EPA's Greenhouse Gas Equivalencies Calculator.

132 Petron et al. (2014).

133 EPA Office of Inspector General, (2013) EPA Needs to Improve Air Emissions Data for the Oil and Natural Gas Production Sector. Report No. 13-P-0161, at 17. Available at: *http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf.*

134 Earthjustice et al., Petition for Reconsideration of Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants, Dkt. No. EPA-HQ-OAR-2010-0505-4591.

135 Earthjustice et al. (2014), Petition to the United States Environmental Protection Agency: EPA must list oil and gas wells and associated equipment as an area source category and set national air toxics standards to protect public health. Available at: *http://earthjustice.org/sites/default/files/files/OilGasToxicWellsPetition51314.pdf.*

136 CTGs are applied to areas in moderate or worse non-attainment of ozone standards. The percentages of nationwide oil and gas production in these areas were calculated using a commercial database of oil and gas well production. The percentage of nationwide gas processing in these areas was calculated using a nationwide list of 905 gas processing plants compiled by ICF International using public data from Oil and Gas Journal, the GHG Reporting Program, and the US Energy Information Administration.

137 This counter-intuitive outcome is the result of the methane standards' potential ability to reach more sources due to the structure of the Clean Air Act, as described in Box 2. It is important to note, however, that adopting methane standards should not be viewed as sufficient to fulfill EPA's statutory obligations regarding VOCs and HAPs, or as an endorsement of "surrogate" approaches more generally.

138 See R. Fernandez, "Proposed Gas STAR Gold Program," Natural Gas STAR Annual Implementation Workshop, San Antonio, 12 May 2014. Available at: *http://www.epa.gov/gasstar/documents/workshops/2014_AIW/Overview_Gold_Certification.pdf.*

139 Data for ConocoPhillips' 2013 emissions in the San Juan basin from the GHG Reporting Program.

140 Xu, Conglin. "Capital spending in US, Canada to rise led by pipeline investment boom." Oil and Gas Journal. March 4, 2013. Available at: *http://www.ogj.com/articles/print/volume-111/issue-3/ s-p-capital-spending-outlook/capital-spending-in-us-canada-to-rise.html.* Calculation includes investments in Exploration-production and Natural gas pipelines.

141 Calculated using 2013 data from EIA on sales of natural gas (volume and price) to commercial, residential, industrial, and electrical utility customers, and for volume and price of domestic crude oil production.

142 See United States Government Interagency Working Group on Social Cost of Carbon, (2013) "Technical Support Document—Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" (November 2013 revision) at 2. Available at: *http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.*

143 In OMB's methodology, the central value for the social cost of carbon dioxide is the value calculated with a 3% discount rate. Id. at 12.

144 Marten, A.L., and S.C. Newbold, (2012) "Estimating the social cost of non-CO_2 GHG emissions: Methane and nitrous oxide." *Energy Policy*, 51, 957.

TECHNICAL APPENDIX

General Assumptions

All emissions and abatement quantities have been converted from short tons to metric tons, where appropriate.

We used the following conversion factors to convert between metric tons and standard cubic feet (scf):

	Methane Content of Gas by Volume	Standard Cubic Feet per Metric Ton
Production	83%	62,055
Processing	87%	59,202
Transmission, Storage, and Distribution	94%	54,793

We use a 7 percent interest rate when calculating annual costs.

Costs for the measures we examine in this report can be calculated in two ways, depending on whether revenue from selling gas kept in the system by the control measure is subtracted from the cost of implementing the measure or not. For each measure in the Production, Processing, and Distribution segments, we present both cost estimates. For the net cost estimate (with the revenue from increased sales subtracted from the cost), we assumed a value of $4 per thousand cubic feet (Mcf) of saved gas. In the Distribution segment, the actual ability of companies to directly realize revenue from this saved gas may vary from state to state due to regulatory differences. In the Transmission and Storage segment, companies are generally not able to capture the value of saved gas because in most cases they do not own the gas that they are transporting or storing, so we only calculated the abatement cost without the value of saved gas.

The overall costs we present in the report are calculated using the net costs (with the revenue from increased sales subtracted from the cost) for measures in the production, processing, and distribution segments. For transmission and storage, we use the abatement cost without the value of the saved gas.

A NOTE ON U.S. GHG INVENTORY DATA, CALCULATING NET EMISSIONS

We rely on Annex 3 of the U.S. GHG Inventory for much of our detailed data on current emissions. In section 3.5 of Annex 3, Tables A-125 through A-130, the Inventory reports emissions from Natural Gas Systems, and in Table A-147 it reports emissions from Petroleum Systems. For all data in the Petroleum Systems section and for a few technologies in the Natural Gas section, the EPA directly reports Net Emissions: gas well completions and workovers with hydraulic fracturing, liquids unloading, condensate storage tanks, and centrifugal compressors. For all other sources, the data reported in Tables A-125 through A-130 are Potential Emissions, and we must subtract reported Reductions in order to calculate Net Emissions. These Reductions, from the Natural Gas Star program and regulations, are reported in Tables A-135 and A-136. Some of these reductions are itemized and the reduction is attributed to a specific technology source, like Chemical Injection Pumps. Here, we subtract Reductions from the Potential Emissions to calculate Net Emissions. In other cases, the reduction is not itemized and the reduction is attributed to the entire sector, like Production. In the latter case, we have distributed these non-itemized reductions proportionally among all the technology sources in the sector.

1. Leaks

CURRENT EMISSIONS: 2,380,000 METRIC TONS

We calculated current emissions from leaks starting with leak emissions reported in the U.S. GHG Inventory. Leak emissions are divided up among a number of activity categories in the inventory. We then added in non-seal emissions that had been subtracted from the Compressor section (see section 3 of the appendix). Finally, we added in an estimate of leaks from offshore oil and gas production based on data from BOEM.

Sector	U.S. GHG Inventory Annex 3[1]	Activity	Other Leaks (Metric tons)	Leaks from Compressors (Metric tons)	Total Leaks (Metric tons)
Gas Production	Table A-125	Non-associated gas wells, unconventional gas wells, heaters, separators, dehydrators, meters/piping	191,848	45,419	237,267
Oil Production	Table A-147	Fugitive Emissions (all), Sales areas, Battery pumps	47,913	1,587	49,500
Offshore Oil and Gas Production	BOEM[2]		90,900		90,900
Processing	Table A-128	Plants	25,938	383,000	408,938
Transmission and Storage	Table A-129	Compressor Stations (Transmission) Stations, M&R (Trans. Co. Interconnect), M&R (Farm Taps + Direct Sales), Compressor Stations (Storage) Stations, Wells (Storage), LNG Storage Stations, LNG Import Terminals Stations	201,991	924,055	1,126,046
Large Aboveground Distribution	Table A-130	Meters/Regulator (City Gates) M&R>300, M&R 100-300, Reg>300, Reg 100-300	471,023		471,023
TOTAL			1,029,614	1,354,060	2,383,674

ABATEMENT POTENTIAL: 1,730,000—1,800,000 METRIC TONS

The Colorado Rule assumes 60 percent abatement from quarterly inspections and 80 percent abatement from monthly inspections, compared to a baseline of no LDAR surveys.[3] Thus, abatement depends on the survey frequency that we assume.

Sector	Survey Frequency	Abatement
Production	Tiered (like Colorado)	60–80%
Processing	Monthly	80%
Transmission and Storage	Monthly	80%
Distribution	Quarterly	60%

We discount onshore production abatement by 5.8 percent (the percent of US gas production that comes from Colorado) to reflect the fact that Colorado has recently enacted rules to require LDAR at production facilities in the state, so as not to double count emissions reductions that will occur without EPA action.

COSTS

Costs are based on the Colorado rulemaking analysis, the Carbon Limits report,[4] and an analysis of EPA data for the costs of LDAR at aboveground distribution facilities. As we note in the main text, the Carbon Limits figures overestimate the abatement costs of LDAR at all facility types because the report only quantifies emissions reductions from observed leaks, and the vast majority of the facilities had been surveyed previously, due to established Canadian LDAR rules. Because LDAR surveys are not being carried out at most U.S. facilities, the volume of leaks from a typical U.S. facility will be higher than the average volume of leaks from the facilities surveyed in the Carbon Limits study. As a result LDAR will reduce leak emissions more than the Carbon Limits data shows, since their data only shows the leak reductions observed, not the leak reductions from higher leak levels if previous surveys had not been performed. Since the net cost of repairs is quite low (or negative) and the cost of surveys is unaffected by the volume of leaks found, the overall result is that the Carbon Limits overestimates the cost per ton of methane abatement from LDAR surveys.

For production, we looked at the Colorado analysis of methane abatement cost effectiveness at well production facilities and at compressor stations. The Colorado cost analysis is based on a tiered LDAR system: LDAR frequency is determined by potential to emit. We present an abatement range based on the fact that some facilities will be surveyed monthly and some will be surveyed quarterly, and a single cost estimate represents the entire tiered system. For simplicity, we use this overall cost for the entire system (as modified below), implying a tiering similar to Colorado's. Colorado presents net costs of $805/ton methane-ethane at well production facilities and $427/ton methane-ethane at compressor stations. The Colorado analysis calculated these net figures assuming a $3.5/Mcf price of natural gas. We adjust these values based on the $4/Mcf that we assume in the rest of the report. We get $448/ton methane-ethane for compressor stations and $799/ton methane-ethane for well production facilities. Taking a weighted average of these based on emission reduction potential, we found an aggregate cost of $765/ton methane-ethane. The abatement costs reported by Colorado were in units "dollars per ton methane-ethane." So, we then need to convert $/ton methane-ethane to $/ton methane to make their numbers consistent with all the other cost numbers in our report. Based on a 2011 memo from ECR Inc. to the EPA on "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking,"[5] we assume that in the production sector, gas is 65.7 percent methane and 10.6 percent ethane by weight. Thus, methane is 86.1 percent of this methane-ethane mix. We use this ratio to adjust the cost figures derived from the Colorado rulemaking. We also used data presented in the Cost-Benefit Analysis for the Colorado rule to calculate gross abatement costs by removing the reported value of saved gas.[6]

For processing, we use the monthly survey figure for gas processing plants from the Carbon Limits report.

For Transmission and Storage, we present an abatement cost range. On the high end of the range, we use the monthly survey figure for compressor stations from the Carbon Limits report.[7] This category combines data for compressor stations in both the gathering and boosting segments and the transmission and storage segments. Compressor stations in the transmission and storage segments are typically much larger than those in gathering and boosting, and thus have a higher leak potential. Therefore, the cost estimate that we use is likely an overestimate.[8] Because this is likely an overestimate, we present a low estimate based on the ICF Methane Cost Curve Report. The ICF report presents costs of $2.15 per Mcf for quarterly LDAR in the transmission sector (without gas credit), which is $118 per ton methane.[9] We can multiply this abatement cost by 3 to get a rough sense of monthly LDAR costs.

For large aboveground distribution facilities, we used cost estimates from the EPA's Marginal Abatement Cost study. Table C-1 in the appendix provides data on incremental reductions and annual cost/savings. We used a weighted average of 4 categories: M&R>300, M&R 100-300, Reg>300, and Reg 100-300.[10]

METHANE EMISSIONS REDUCTIONS OPPORTUNITIES AND COSTS FOR LEAKS

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Abatement Cost per Ton of Methane Reductions (assuming $4/ Mcf gas)
Production (tiered)	378,000	217,000–289,000	$1,100	$890
Processing (monthly)	409,000	327,000	$1,100	$840
Trans. & Storage (monthly)	1,130,000	901,000	$350–$1,570	$350–$1,570
Distribution (quarterly)	471,000	283,000	$620	$410

LEAKS NOTES

1 US Environmental Protection Agency (EPA). US Greenhouse Gas Inventory, 2014. Annex 3. Available at: *http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf.*

2 Bureau of Ocean Energy Management (BOEM). Year 2008 Gulfwide Emission Inventory Study, Table 8-10. Available at: *http://www.data.boem.gov/PI/PDFImages/ESPIS/4/5056.pdf*

3 Colorado Department of Public Health and Environment, Cost-Benefit Analysis, Submitted Per § 24-4-103(2.5), C.R.S. p. 27. Available at: *ftp://ft.dphe.state.co.us/apc/AQCC/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf.*

4 Carbon Limits, Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (2014). Pg. 8 Available at: *http://www.catf.us/resources/publications/view/198.* Converted from CO_2e to CH4 at 25 GWP

5 Brown, H.P, (2011), "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking," Table 5. Available at *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.*

6 Carbon Limits (2014). Tables 26, 30, 32, and 34.

7 Ibid.

8 Carbon Limits (2014). Pg. 30. Gathering compressor stations versus transmission compressor stations.

9 ICF Cost Curve (2014). Table 3–4: Cost Calculation–Quarterly LDAR.

10 US Environmental Protection Agency (EPA). (September 2013). "Global Mitigation of Non-CO_2 Greenhouse Gases: 2010–2030." Appendix Pg. C-5,C-6. Available at: *http://www.epa.gov/climatechange/Downloads/EPAactivities/MAC_Report_2013-Appendixes.pdf.*

2. Pneumatics

Controllers

CURRENT EMISSION: 1,300,000–1,530,000 METRIC TONS

For current emissions for pneumatic controllers, we used data from several sources. For oil and gas production, we use data from the 2013 GHG Reporting Program, corrected with the more up-to-date emissions factors for pneumatic controllers from Allen et al. (2013). For gas processing, we use data from the U.S. GHG Inventory directly (no data is available for pneumatic controllers in gas processing from the GHG Reporting Program). For transmission and storage, we consider data from both the GHG Reporting Program and the U.S. GHG Inventory, and report data from on both (as a range).

Production: The GHG Reporting Program is based on data reported directly from companies. Reporters count the number of controllers at their facilities and multiply that number by emissions factors published by EPA, accounting for the fraction of methane in the vented gas. However, only a subset of facilities (those emitting above 25,000 metric tons of CO_2 equivalent per year) report data, so the Reporting Program only accounts for emissions from a subset of oil and gas production facilities. Nevertheless, emissions reported in the U.S. GHG Inventory are lower than emissions reported in the GHG Reporting Program (756,737 metric tons compared to 974,200 metric tons). The Reporting Program and the Inventory both use the same data for emissions per individual controller, so the difference between the emissions from controllers in the Inventory and the Reporting Program is in the underlying data/assumptions for the number of controllers in use. Since the Reporting Program is clearly an underestimate of the actual number of controllers in use—since smaller facilities do not report to the program—but implies a larger number than the Inventory data implies, it is clear that the Reporting Program data is more accurate.

We then adjusted emissions reported in the GHG Reporting Program based on emissions factors for low-bleed and intermittent-bleed controllers from Allen et al. (2013). These measurements are both much more recent and based on larger numbers of controllers than the data EPA used to calculate the emissions factors which reporters use when they calculate emissions from their controllers.[11] We adjusted the GHGRP emissions in the production segment using these new emissions factors.

Transmission and Storage*:* Emissions reported in the GHG Reporting Program for this segment are very low, most likely because many facilities in those segments fall below the 25,000 metric ton threshold for reporting. Thus, in this segment, we use the GHG Reporting Program data as a low estimate and the GHG Inventory data as a high estimate. (Allen et al. (2013) did not measure pneumatic controllers in the transmission and storage segments, so we cannot similarly adjust the reported values for those sectors).

In summary, the lower end of the range of current emissions for pneumatic controllers (which totals approximately 1,300,000 metric tons) includes the adjusted GHGRP value for production, the GHG Inventory value for processing, and the reported GHGRP value for transmission and storage. The higher end of the range (which amounts to approximately 1,530,000 metric tons) includes the adjusted GHGRP value for production, the GHG Inventory value for processing, and the GHG Inventory value for transmission and storage emissions.

	U.S. GHG Inventory (metric tons)	Source Annex 3	GHGRP—as Reported (metric tons)	Source	GHGRP—Adjusted with Allen, et al. (metric tons)	Low Estimate	High Estimate
Gas Production	334,419	Table A-125	974,200	EPA Envirofacts[12] Table W_PNEUMATIC_ DEVICE_TYPE	1,290,730	1,290,730	1,290,730
Oil Production	422,318	Table A-147					
Processing	1,481	Table A-128	not reported			1,481	1,481
Transmission	207,157	Table A-129	7,600			7,600	207,157
Storage	31,028	Table A-129	4,462			4,462	31,028
TOTAL	996,403		873,299			1,304,274	1,530,396

EMISSIONS FACTORS

	Low Bleed	Intermittent Bleed	High Bleed	Low Bleed	Intermittent Bleed	High Bleed
	scf/hour-component			Metric tons/year-component		
Production						
GHGRP[13]	1.39	13.5	37.5	0.20	1.91	5.29
Allen et al.[14]	5.1	17.4	—	0.72	2.46	—
Transmission and Storage						
GHGRP[15]	1.4	2.4	18.2	0.22	0.38	2.91

COUNTS OF CONTROLLERS (BASED ON GHGRP EMISSIONS DATA AND ACTIVITY FACTORS)

	Low Bleed	Intermittent Bleed	High Bleed
Oil and Natural Gas Production	174,220	409,207	30,258
Transmission and Storage	1,587	11,956	2,482

ABATEMENT POTENTIAL: 518,000 TO 665,000 METRIC TONS

We calculated the abatement potential for converting to low-bleed and zero-bleed devices based on the above emissions factors. For the Production segment, we use the Allen et al. emissions factors for low- and intermittent-bleed devices, and the original GHGRP emissions factors for high-bleed devices (because Allen et al. did not report emissions for high-bleed controllers). For the Transmission and Storage Segments, we use the GHGRP emissions factors.

We first assumed that 20 percent of pneumatic controllers in production and transmission and storage are located at facilities that are either located where grid power is available, or are at larger facilities where onsite electrical generation is already occurring or would be feasible and cost-effective. For these facilities, we assume conversion of all controllers to zero-bleed (and calculate costs accordingly). We then account for cases where high-emitting devices (continuous-bleed or intermittent bleed) cannot be replaced with low-bleed or zero-bleed, because of safety or process purposes. For replacement of high-bleed controllers, based on the experience of regulations in the Denver-Julesberg basin in Colorado, where no exemptions were requested to the rule requiring replacement of *all* high-bleed controllers, we assume that 95 percent of high-bleed devices can be replaced with low- or zero-bleed devices (75 percent low-bleed and 20 percent zero-bleed). Consistent with the assumptions made in the ICF Methane Cost Curve report,[16] we assume that only 25 percent of intermittent-bleed devices will be replaced with low-bleed to account for the fact that some intermittent-bleed devices already emit a low amount of methane; we also assume that another 20 percent of intermittent controllers can be replaced with zero-bleed (as above). Consistent with the NSPS OOOO rule for pneumatic devices in the processing segment, we assume that all existing devices in the processing segment are replaced with zero-bleed devices.[17]

The range in abatement for the transmission and storage sector reflects the range in our estimate for current emissions. For the low estimate, we apply the new emissions factor directly to the GHGRP data. For the high estimate, we use the estimate from the GHG Inventory and assume that the ratio of high-, intermittent-, and low-bleed devices is the same as that observed in the GHGRP (the GHG Inventory does not include a breakdown of these different device types). For the low estimate, we use the data directly reported to the GHG Reporting Program.

Segment	Conversion	Starting Emissions Factor	Final Emissions Factor	Percent of Devices Switched	Abatement (metric tons)
Production	High–>Low	37.5	5.1	75%	64,547[18]
	High–>Zero	37.5	0.0	20%	32,035
	Intermittent–>Low	17.4	5.1	25%	177,630
	Intermittent–>Zero	17.4	0	20%	201,025
	Low–>Zero	5.1	0	20%	32,935[18]
Processing	All–>Zero		0	100%	1,481
Transmission	High–>Low	18.2	1.4	75%	2,425 to 86,034
	High–>Zero	18.2	0	20%	699 to 24,810
	Intermittent–>Low	2.35	1.4	25%	406 to 8,042
	Intermittent–>Zero	2.35	0	20%	779 to 15,428
	Low–>Zero	1.4	0	20%	41 to 1,194

COSTS

Costs for converting pneumatic devices in the processing sector to zero-bleed devices are taken directly from the NSPS 2011 Technical Support Document, Table 5-12.[19]

For the Production and Transmission & Storage segments, first we calculated costs for conversion to low-bleed pneumatics, then we calculated costs for conversion to zero-bleed pneumatic systems, and finally we calculate a weighted average to determine average costs for each segment.

The average cost of installing a new low-bleed pneumatic device ranges from $169[20] to $427.[21] We calculated abatement costs using these cost per component figures and the difference in the emissions factor between high- or intermittent- and low-bleed pneumatic controllers.

Sector	Conversion	Annual Cost per Device		Methane Reduced		Abatement Cost without Value of Saved Gas		Annual Value of Saved Gas per device	Abatement Cost with Value of Saved Gas	
		$/device/year		scf/hour/ component	ton/ year	$/metric ton		(assuming $4/Mcf)	$/metric ton	
		Low	High			Low	High		Low	High
Production	High –>Low	$169	$427	32.4	4.90	$37	$93	$1,135	($211)	($155)
Production	Intermittent –>Low	$169	$427	12.3	1.86	$97	$246	$431	($151)	($2)
Transmission and Storage	High –>Low	$169	$427	16.8	3.03	$63	$159	$0	$63	$159
Transmission and Storage	Intermittent –>Low	$169	$427	1.0	0.18	$1,079	$2,725	$0	$1,079	$2,725

We estimated costs for installing zero-bleed pneumatic systems based on data and equations from a Lessons Learned document from EPA's Natural Gas Star program: "Convert Gas Pneumatic Controls To Instrument Air," and we used conservative assumptions for converting small production facilities to zero-bleed. We assumed that conversion to zero-bleed would affect all pneumatic controllers at a facility and that each well production facility had 3 controllers (1 high-bleed, 1 intermittent-bleed, and 1 low-bleed). We calculated annual equipment costs (small air compressor and small air dryer), electricity costs (10 horsepower engine and 6.82 cents/kWh for an industrial customer), and gas savings (based on savings from 1 high-bleed, 1 intermittent-bleed, and 1 low-bleed pneumatic device). We calculate a $980/ton abatement cost and $750/ton net abatement cost with the value of saved gas. We applied these same costs for the High→Zero switch, the Intermittent→Zero switch, and the Low→Zero switch, because costs are based on facility conversion, not individual controller conversion.

Finally, we calculated average abatement costs for the Production and Transmission & Storage segments, weighted based on relative emissions abated by each conversion type in each industry segment.

METHANE EMISSIONS REDUCTIONS OPPORTUNITIES AND COSTS FOR PNEUMATIC CONTROLLERS

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Net Abatement Cost per Ton of Methane Reductions Assuming $4/Mcf Gas
Pneumatic Valve Controllers				
Production	1,140,000	508,000	$550–$610	$310–$370
Processing	1,480	1,480	$740	$510
Trans. & Storage	12,100–238,000	7,890–156,000	$400–$690	$400–$690

Pumps

CURRENT EMISSIONS: 342,000 METRIC TONS

Emissions for pneumatic pumps were taken directly from the 2014 U.S. GHG Inventory.

Segment	Chemical Injection Pumps	Kimray Pumps	Source Annex 3
Production (Gas)	64,541	223,977	Table A-125
Production (Oil)	49,973	0	Table A-147
Processing	0	3,859	Table A-128

ABATEMENT POTENTIAL: 206,000 METRIC TONS

We use abatement assumptions drawn from the ICF Methane Cost Curve Report. Approximately 80 percent of chemical injection pumps can be replaced with electric pumps driven by solar energy, and 50 percent of Kimray pumps can be replaced with electric motor-driven pumps.[22] In both cases, the new pump completely eliminates emissions when it is implemented.

Segment	Chemical Injection Pumps	Kimray Pumps	Total
Production (Gas)	51,633	111,989	163,622
Production (Oil)	39,978	0	39,978
Processing	0	1,929	1,929

COSTS

Costs for Kimray pumps and Chemical Injection Pumps are taken from the ICF Methane Cost Curve Report.[23]

METHANE EMISSIONS REDUCTIONS OPPORTUNITIES AND COSTS FOR PNEUMATIC PUMPS

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Net Abatement Cost per Ton of Methane Reductions Assuming $4/Mcf Gas
Pneumatic Pumps				
Production	338,000	204,000	$140	($180)
Processing	3,860	1,930	$56	($260)

PNEUMATICS NOTES

11 Allen, David, T., et al. 2013. Measurements of methane emissions at natural gas production sites in the United States. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs. Available at: *http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html.*

12 US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_PNEUMATIC_DEVICE_TYPE. Available at: *http://www.epa.gov/enviro/facts/ghg/customized.html.*

13 40 CFR 98, subpt W, Table W-1A. Available at: *http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=0c3d3ddf4b6741d9088476b986a5e429&ty=HTML&h=L&n=40y21.0.1.1.3&r=PART#ap40.21.98_1238.1*

14 Allen, et al,. Supporting Information at S-31. Available at: *http://www.pnas.org/content/suppl/2013/09/11/1304880110.DCSupplemental/sapp.pdf.*

15 40 CFR 98, subpt W, Table W-3. Available at: *http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=0c3d3ddf4b6741d9088476b986a5e429&ty=HTML&h=L&n=40y21.0.1.1.3&r=PART#ap40.21.98_1238.6.*

16 ICF International. (2014) "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," p. B-5, B-6. Available at: *http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.*

17 High-(continuous) bleed controllers may only be newly installed at production facilities "based on functional needs, including but not limited to response time, safety and positive actuation." (40 C.F.R. § 60.5390(a)). There are relatively few existing pneumatic controllers that bleed natural gas in processing.

18 We discount abatement from high-bleed pneumatic controllers in the production segment based on the fact that Colorado has already required that these controllers be replaced with low-bleed controllers (from 104,000 to 64,600 metric tons). To account for the fact that this will lead to the presence of more low-bleed pneumatic devices, and to remain consistent with our assumption that 20 percent of low-bleed pneumatic controllers will be replaced with zero-bleed controllers, we increase our estimate of abatement from low-bleed controllers (from 25,100 to 32,900 metric tons).

19 EPA TSD (2011).

20 CDPHE Cost-Benefit Analysis. Pg. 32-33. Uses a 5 percent interest rate over 15 years.

21 ICF International. (2014) "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," p. 3-16. Available at: *http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.* $300 but recalculated with 7 percent interest rate over 10 year.

22 Ibid.

23 Id. At 3-22.

3. Compressor Seals

Reciprocating

CURRENT EMISSIONS: 317,000 METRIC TONS

We calculated current emissions for reciprocating compressor seals in a two-step process: 1) we started with compressor emissions reported in the U.S. GHG Inventory, 2) we subtracted non-seal emissions based on source cited in the inventory.

Sector	U.S. GHG Inventory Reported Compressor Emissions (metric tons)	Source: U.S. GHG Inventory 2014, Annex 3[24]	Percent of Emissions from Seal	Source EPA/GRI, Volume 8[25]	Calculated Emissions for Existing Reciprocating Compressor Seals (metric tons)
Gas Production	50,348	Table A-125	10%	Table 4-8	4,929
Oil Production	1,759	Table A-147	10%	Same as Gas Production	172
Gas Processing	340,882	Table A-128	28%	Table 4-14	95,072
Gas Transmission	772,736	Table A-129	24%	Table 4-17	182,211
Gas Storage	150,116	Table A-129	18%	Table 4-24	26,285
LNG	45,665	Table A-129	18%	Same as Storage	7,996
TOTAL	1,361,506				316,666

ABATEMENT POTENTIAL: 251,000 METRIC TONS

We use data presented in the OOOO 2011 TSD Tables 6-5 and 6-6 to calculate the abatement percent from replacing rod packing at reciprocating compressors every three years or 26,000 operating hours. This data presents baseline emissions and emissions reductions for new compressors that are covered in OOOO. We assume that replacing rod packing at existing compressors will achieve the same abatement as replacing rod packing at new compressors, so we apply these same abatement percentages to existing compressors. Since older compressors may not have had rod packing replaced for some time, this assumption is probably conservative. We multiply these percent reductions by current emissions to calculate potential abatement.

	Baseline Emissions for New Compressors (metric tons)	Source:	Emissions Reductions for New Compressors (metric tons)	Source:	Percent Abatement	Abatement Potential for Existing Compressors (metric tons)
Production (well pads)	1,186	Table 6-5	947	Table 6-6	79.8%	NA[26]
Gathering and boosting	2,587	Table 6-5	1,437	Table 6-6	55.5%	2,669[27]
Processing	4,871	Table 6-5	3,892	Table 6-6	79.9%	75,964
Transmission	529	Table 6-5	423	Table 6-6	80.0%	145,700
Storage	113	Table 6-5	87	Table 6-6	77.3%	20,307
LNG	113	Assume same as storage	87	Assume same as storage	77.3%	6,177
TOTAL						250,818

COSTS

We base our cost estimates for reciprocating compressor seals on cost figures presented in the OOOO 2011 Technical Support Document.[28] We use OOOO costs for Gathering and Boosting to represent costs for reciprocating compressors in the Production segment (instead of using Well Pad costs), because we think that these more accurately represent costs in this segment.

For each segment, we calculate annual costs and abatement costs without including the value of saved gas. As part of this calculation, we include an operating factor, which is the percent of hours in a year that the compressor is used. This factor varies among segments of the industry. The factor is relevant because the higher the percent, the more quickly the compressor will reach 26,000 hours of operating time and therefore there the shorter the time to annualize over. Then we calculate the value of saved gas to find the net abatement costs.

	Individual Compressor Emission Reductions							
	Short tons/ compressor-year	**Metric tons/ compressor-year**	**Number of Cylinders**	**Cost per Cylinder**	**Capital Cost**	**Operating Factor (% of hour/ year compressor pressurized)**	**Annual Cost ($/component)**	**Abatement Cost ($/metric ton)**
Gathering and Boosting	6.84	6.21	3.3	$1,620	$5,346	79.1%	$1,669	$269
Processing	18.60	16.87	2.5	$1,620	$4,050	89.7%	$1,413	$84
Transmission	21.70	19.69	3.3	$1,620	$5,346	79.1%	$1,669	$85
Storage	21.80	19.78	4.5	$1,620	$7,290	67.5%	$1,983	$100
Source:	0000 2011 TSD Table 6-6		0000 2011 TSD Table 6-2	0000 2011 TSD Pg 6–16	0000 2011 TSD Table 6-7	0000 2011 TSD Table 6-2		

	Annual Gas Savings (metric tons/ component/year)	**Annual Revenue from Natural Gas (assuming $4/Mcf)**	**Net Annual Cost/Savings ($/component)**	**Net Abatement Cost/Savings—Including Value of Saved Gas ($/metric ton)**
Gathering and Boosting	6.21	$1,540	$129	$21
Processing	16.87	$3,996	($2,582)	($153)
Transmission	19.69	$0	$1,669	$85
Storage	19.78	$0	$1,983	$100

Centrifugal

CURRENT EMISSIONS: 249,000 METRIC TONS

We calculated current emissions for centrifugal compressor seals in a two-step process: 1) we started with compressor emissions reported in the U.S. GHG Inventory, 2) we subtracted non-seal emissions based on source cited in the inventory.

Sector	**Centrifugal Compressors Wet Seal (metric tons)**	**Centrifugal Compressors Dry Seal (metric tons)**	**Source: U.S. GHG Inventory 2014, Annex 3**[29]	**Percent of Emissions from Wet Seal**	**Percent of Emissions from Dry Seal**	**Source ICF Memo**[30]	**Calculated Wet Seal Centrifugal Compressor Emissions (metric tons)**	**Calculated Dry Seal Centrifugal Compressor Emissions (metric tons)**
Gas Processing	237,724	43,937	Table A-128	58%	15%	Exhibit 3	137,880	6,590
Gas Transmission	232,826	14,972	Table A-129	41%	8%	Exhibit 3	95,459	1,198
Gas Storage	22,347	6,532	Table A-129	34%	6%	Exhibit 3	7,598	392
LNG	[31]	[31]					[31]	[31]
TOTAL	492,897	65,440					240,936	8,180

ABATEMENT POTENTIAL: 229,000 METRIC TONS

For wet seal centrifugal compressors, we assume 95 percent abatement through capturing gas from the degassing unit, based on data from the OOOO 2011 TSD.[32] There is no additional abatement for dry seal compressors.

Sector	Abatement from Wet Seal Centrifugal Compressors	Abatement from Dry Seal Centrifugal Compressors
Gas Processing	130,986	0
Gas Transmission	90,686	0
Gas Storage	7,218	0
TOTAL	228,890	0

COSTS

We base our cost estimates for centrifugal compressor seals in the processing segment on cost figures presented in the OOOO 2012 and 2011 Technical Support Documents.[33] First we calculate annual costs and abatement costs without including the value of saved gas. Then we calculate the value of saved gas to find the net abatement costs. We assume that the annual cost per unit is the same in the Processing and Transmission/Storage segments, but the EPA indicates that emissions reduction is lower in the Transmission/Storage segments than in the Processing segment. This leads to a higher abatement cost in the Transmission/Storage segments.

	Annual Cost ($/component)	Individual Compressor Emission Reduction–95% control		Abatement Cost ($/metric ton)	Revenue from Natural Gas (Assuming $4/Mcf)	Net Cost/ Savings $	Net Abatement Cost/Savings—Including Value of Saved Gas $/Metric Ton
		Short Ton	Metric Ton				
Processing	$3,132	216	196	$16	$41,276	($46,436)	($221)
Transmission and Storage	$3,132	120	109	$29	$0	$3,132	$29
Source:	OOOO 2012 TSD Section 6.3	OOOO 2011 TSD Table 6-10					

ALL COMPRESSORS

We calculated the aggregate abatement costs for compressors by taking the average of costs for reciprocating and centrifugal, weighted based on amount of abatement.

Methane Emissions Reductions Opportunities and Costs For Compressors

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Abatement Cost per Ton of Methane Reductions (assuming $4/Mcf gas)
Production	5,100	2,670	$270	$21
Processing	240,000	207,000	$41	($200)
Transmission and Storage	321,000[34]	270,000	$66	$66

COMPRESSOR NOTES

24 US Environmental Protection Agency (EPA). Greenhouse Gas Inventory, Annex 3 Available at: *http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf.*

25 GRI-EPA. (June 1996). "Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks." Available at: *http://www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf.*

26 OOOO separates Well Pads from Gathering and Boosting. But, the GHG Inventory combines these two categories in the Production segment. To be conservative, we apply the lower of the two abatement percent figures (55.5 percent instead of 79.8 percent) to all production emissions).

27 We discount onshore production abatement by 5.8 percent to reflect the fact that Colorado has recently enacted rules to require OOOO for existing compressors at production facilities in the state, so as not to double count emissions reductions that will occur without EPA action.

28 US Environmental Protection Agency (EPA). (July 2011). Technical Support Document (TSD) for Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Available at: *http://epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.*

29 *EPA, GHG Inventory.*

30 ICF International.

31 For LNG terminals, the Inventory does not distinguish between wet and dry seal centrifugal compressors, so we are unable to apportion the percent of emissions that come from compressor seals vs. static leaks. Therefore, we do not include these emissions in our current emissions.

32 EPA TSD (2011). Pg. 6–23.

33 EPA TSD (2011) and US Environmental Protection Agency (EPA). Technical Support Document, Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. April 2012. Available at: *http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.*

34 As above, emissions from centrifugal compressors in the LNG segment are excluded.

4. Oil Wells

CURRENT EMISSIONS: 145,000 TO 402,000 METRIC TONS

Based on emissions reported in GHG Reporting Program from 2011–2013.

	Current Emissions Low Estimate	Current Emissions High Estimate	Source:
Oil Well Completions	96,000	247,000	EDF, Co-producing Wells report[35]
Oil Well Production Venting	50,775	155,418	Range of emissions reported to GHG Reporting Program from 2011–2013

ABATEMENT POTENTIAL: 138,000 TO 382,000 METRIC TONS

We assume a 95 percent abatement for both completion and production emissions based on REC efficiency and other gas capture techniques. In 2012 EPA concluded that RECs can reduce completion emissions by 95 percent,[36] and recent research suggests that when properly carried out the emissions reduction can be even greater.[37]

	Abatement Low Estimate	Abatement High Estimate
Oil Well Completions	91,200	234,650
Oil Well Production Venting	48,236	147,647

COSTS

Costs for Oil Well Venting and Oil Well Associated Gas emissions reductions are taken from the ICF Methane Cost Curve Report.[38]

In order to reduce completion emissions, oil producers must get pipelines to wells before they are completed, and use REC equipment to capture gas so it can be directed into the pipeline. Net abatement costs assume the gas is captured rather than flared. While gathering associated gas with pipeline systems or using the alternative technologies are generally profitable, we use a cost of $16 per metric ton of avoided methane emissions (an estimate of the cost of flaring)[39] as an estimate of the overall cost of eliminating methane emissions from associated gas venting. To be conservative, we do not factor in the value of gas sold when calculating abatement cost for production venting from oil wells.

Methane Emissions Reductions Opportunities and Costs For Oil Wells

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Abatement Cost per Ton of Methane Reductions (assuming $4/Mcf gas)
Oil Wells—Completions	96,000–247,000	91,200–235,000	$120	($133)
Oil Wells—Production Venting	50,800–155,000	48,200–148,000	$16	$16

OIL WELLS NOTES

35 Environmental Defense Fund (2014), “Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses,” Table 1. *http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf.*

36 EPA TSD (2012). Section 5.1.

37 Allen, D., et al (2013).

38 ICF Cost Curve (2014). Pg. 3–22.

39 Ibid. ICF International calculated that flaring gas during oil production would cost $0.26 per Mcf of avoided venting or $15 per metric ton of avoided methane emissions.

5. Liquids Unloading

CURRENT EMISSIONS: 177,000 METRIC TONS

Emissions for liquids unloading were taken directly from the 2013 GHG Reporting Program.

	Liquids Unloading	Source
Wells with Plunger Lifts	96,787	EPA Envirofacts[40] Table W_LIQUIDS_UNLOADING
Wells without Plunger Lifts	80,623	
TOTAL	177,409	

ABATEMENT POTENTIAL: 120,000 METRIC TONS

We reviewed the detailed emissions reporting on liquids unloading venting in the GHG Reporting Program for 2013. Liquids unloading venting emissions from around 55,500 wells were reported to the Reporting Program. (Since not all gas well operators report emissions to the Reporting Program, this represents a subset of the total number of wells that vent during liquids unloading). However, 80 percent of reported emissions (143,000 metric tons) are from just 22 percent of those wells—12,058 wells, each of which emits at least 300,000 scf/year. (This subset of wells/emissions accounts for 88 percent of emissions from wells with plunger lifts, and 71 percent of emissions from wells without plunger lifts). Standards for liquids unloading could be targeted at high emitting wells, using this or a similar threshold. These 12,100 wells are just only 2.5 percent of all gas wells nationwide. Of these wells, 7,500 have plunger lifts and 4,600 do not have plunger lifts.

For the subset of high-emitting wells, standards could require that wells with plunger lifts reduce emissions by 80 percent (through the addition of smart automation or using gas capture technology), and wells without plunger lifts reduce emissions by 90 percent (either with plunger lifts and smart automation or gas capture technology).

	Current Emissions (metric tons)	Percent of emissions from wells emitting over threshold	Number of wells emitting over threshold	Emissions from wells that emit over threshold	Percent abatement for wells that emit over threshold	Abatement (metric tons)
Wells with Plunger Lifts	96,787	88%	7,457	85,039	80%	68,031
Wells without Plunger Lifts	80,623	71%	4,601	57,572	90%	51,815
TOTAL	177,409	80%	12,058	142,611		119,846

COSTS

We present information on costs for installing plunger lift systems with smart automation and the incremental cost of adding smart automation at wells that already have plunger lifts. These cost figures are for generic installations, and because the standards we discuss would be targeted at higher-emitting wells, the abatement costs (in dollars per ton of emissions reductions) are probably overestimates, since these measures will reduce venting more when installed on these targeted wells than when installed on a generic well (and the fixed costs for these technologies are not expected to be sensitive to the volume of venting reduction).

First, we calculate annual costs of installing plunger lifts and plunger lifts with smart automation. According to documents from EPA's Natural Gas Star, capital and other startup costs for a plunger lift system range from $2,600 to $10,400 depending on the well and type of installation.[41] Operating costs are between $700 and $1,300.[42] Annualized over 5 years at a 7 percent interest rate and converted from 2006 to 2014 dollars, this results in annual costs of $1,574 to $4,527. EPA Natural Gas Star documents also state that the capital cost required to add smart automation to plunger lift system is between $5,700 and $18,000.[43] We assume that operating costs remain the same as for plunger lifts without smart automation, although smart automation is very likely to reduce operating costs.

Natural Gas STAR Partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdown and an average of 30 Mcf per year by eliminating workovers.[44] Incremental gas savings for the smart automation system are between 600 and 900 Mcf per well.[45]

We divide total annual cost by metric tons abated to find the abatement cost per ton. We determine the value of saved gas by multiplying the Mcf of methane emissions abated by a $4 per Mcf price of gas. Finally, we subtract the value of saved gas from the total annual cost and recalculate the abatement cost including the value of saved gas.

	Capital Cost	Operating Costs	Total Annual Cost (2006$)	Total Annual Cost (2014$) Multiplier = 1.18	Emissions Abatement		Abatement Cost	Value of Saved Gas (assuming $4/Mcf)	Net Abatement Cost
					Mcf/Well	Metric Tons/Well			
Installation of Basic Plunger Lift	$2,600–$10,400	$700–$1,300	$1,334–$3,836	$1,574–$4,527	630	10.2	$155–$446	$2,520	($93)–$198
Incremental Cost of Smart Automation	$5,700–$18,000	$700–$1,300	$2,090–$5,690	$2,466–$6,714	630–900	10.2–14.5	$170–$661	$2,520–$3,600	($78)–$413
Total Cost of Plunger Lift and Smart Automation	$8,300–$28,400	$700–$1,300	$2,724–$8.226	$3,215–$9,707	1,260–1,530	21.7–26.4	$122–$446	$5,040–$6,120	($110)–$215

Industry Segment	Current Emissions (metric tons/yr)	Potential Reductions	Abatement Cost per Ton of Methane Reductions (without value of conserved gas)	Abatement Cost per Ton of Methane Reductions (assuming $4/Mcf gas)
Liquids Unloading—wells without a plunger lift	80,600	51,800	$120–$450	($110)–$220
Liquids Unloading—wells with a plunger lift	96,800	68,000	$170–$660	($78)–$410

LIQUID UNLOADING NOTES

40 US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_LIQUIDS_UNLOADING. Available at: *http://www.epa.gov/enviro/facts/ghg/customized.html.*

41 “Lessons Learned from Natural Gas STAR Partners, Installing Plunger Lift Systems in Gas Wells,” Pg. 1. Available at: *http://epa.gov/gasstar/documents/ll_plungerlift.pdf* .

42 Id. at 4.

43 Lessons Learned from Natural Gas STAR Partners, Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.” Pg. 1. Available at: *http://www.epa.gov/gasstar/documents/ll_options.pdf.*

44 “Lessons Learned from Natural Gas STAR Partners, Installing Plunger Lift Systems in Gas Wells,” Pg. 3.

45 Ibid.

6. Oil and Condensate Storage Tanks

CURRENT EMISSIONS: 292,000–424,000 METRIC TONS

We use emissions reported in the 2013 U.S. GHG Inventory for our high-end emissions estimate for oil and condensate storage tanks:

Sector	U.S. GHG Inventory Annex 3[46]	Activity	Methane Emissions (metric tons)	VOC Emissions (metric tons)[47]	HAP Emission (metric tons)[48]
Gas Production	Table A-125	Condensate Tanks without Control Devices, Condensate Tanks with Control Devices	32,988–164,940	151,000–754,000	4,450–22,300
Oil Production	Table A-147	Oil Tanks, Floating Roof Tanks	259,426	1,180,000	35,000

The ICF Methane Cost Curve report adjusted condensate tank emissions to reflect revised emissions factors. The adjustments they made resulted in an 80 percent decrease in condensate tank emissions.[49] Thus, we reduced U.S. GHG Inventory emissions by 80 percent to estimate a low end of emissions for condensate tanks.

ABATEMENT POTENTIAL: 273,000–377,000 METRIC TONS

We applied a 95 percent abatement to emissions from condensate tanks with out control devices, oil tanks, and floating roof tanks. This is based on emissions reductions from the installation of vapor recovery units (VRUs) required for new tanks in the 2012 NSPS.[50] We did not include any additional emissions from condensate tanks with control devices.

Note: Abatement from oil and condensate tanks is only discussed in Box 4, which is separate from our core Methane Standards Approach.

OIL AND CONDENSATE STORAGE NOTES

46 EPA GHG Inventory, Annex 3.

47 See ratios in section 8.

48 See ratios in section 8.

49 ICF Cost Curve (2014). Pg. B-7.

50 40 C.F.R. § 60.5395(e)(1).

7. Dehydrator Venting

CURRENT EMISSIONS: 36,200 METRIC TONS

Emissions from dehydrator venting are taken from the 2013 U.S. GHG Inventory.

Sector	U.S. GHG Inventory Annex 3[51]	Activity	Methane Emissions (metric tons)	VOC Emissions (metric tons)[52]	HAP Emission (metric tons)[53]
Gas Production	Table A-125	Dehydrator Vents	30,938	89,600	49,400
Gas Processing	Table A-126	Dehydrator Vents	5,270	15,300	8,420

ABATEMENT POTENTIAL: 34,400 METRIC TONS

We assume 95 percent reduction from dehydrator vents based on emission reduction requirements in the Colorado rule.[54]

Note: Abatement from dehydrator vents is only discussed in Box 5, which is separate from our core Methane Standards Approach.

DEHYDRATOR VENTING NOTES

51 EPA GHG Inventory, Annex 3.

52 See ratios in section 8.

53 See ratios in section 8.

54 5 C.C.R. 1001-9 § XVII.D.4. (2014). Available at: *https://www.colorado.gov/pacific/sites/default/files/063_R7-REG-Excerpt-request-11-21-13-19-pgs-063_1.pdf.*

8. Calculating VOC and HAP Emissions Reductions

We calculated VOC and HAP emissions reductions using the following ratios derived from the 2012 NSPS OOOO 2011 Regulatory Impact Assessment, Table 3-3 and Table 3-9.[55] We use these ratios to calculate values in Tables 7 and 8. The data from Table 3-3 and the calculated ratios are presented below:

		Nationwide Emissions Reductions (tons/year)			Calculated Ratios	
		VOC	Methane	HAP	VOC/Methane Ratio	HAP/Methane Ratio
Leaks	Well Pads	10,646	38,287	401	0.278	0.0105
	Gathering and Boosting	2,340	8,415	88	0.278	0.0105
	Processing Plants	392	1,411	15	0.278	0.0106
	Transmission Compressor Stations	261	9,427	8	0.028	0.0008
Reciprocating Compressors	Well Pads	263	947	10	0.278	0.0106
	Gathering and Boosting	400	1,437	15	0.278	0.0104
	Processing Plants	1,082	3,892	41	0.278	0.0105
	Transmission Compressor Stations	12	423	0.45[56]	0.028	0.0011[56]
	Underground Storage Facilities	2	87	0.08[56]	0.023	0.0009[56]
Centrifugal Compressors	Processing Plants	288	3,183	10	0.090	0.0031
	Transmission Compressor Stations	43	1,546	1	0.028	0.0006
Pneumatic Controllers	Oil and Gas Production	25,210	90,685	952	0.278	0.0105
	Natural Gas Trans. and Storage	6	212	0.23[56]	0.028	0.0011[56]
Oil Wells		83	88	3[56]	0.943	0.036[56]
Gas Wells (Liquids Unloading)		857	5,875	62	0.146	0.0106
Storage Vessels	High Throughput	29,654	6,490	876	4.569	0.135
	Low Throughput	6,838	1,497	202	4.568	0.135
Small Glycol Dehydrators	Production	915	316	505	2.896	1.598
	Transmission	298	103	164	2.893	1.592

CALCULATING VOC AND HAP EMISSIONS REDUCTIONS NOTES

55 US Environmental Protection Agency (EPA). (July 2011). Regulator Impact Analysis (RIA) for Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Available at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/oilnaturalgasfinalria.pdf.*

56 The 2012 NSPS OOOO reported a HAP/Methane ratio of zero, which is incorrect. Instead, we derive the HAP/Methane ratio for these sources based on the observation that the VOC/HAP ratio is not more than 26.5 across all of the other sources. We calculate relative HAP reductions, and then calculated HAP/Methane reductions using this value.

9. Potential Reductions from VOC Approach

Potential Methane Reductions from VOC Approach

A VOC rule approach would include both a CTG rule under section 182 covering VOC emissions from oil and gas production and processing facilities located in ozone nonattainment areas, and an expansion of subpart OOOO to cover all new and modified sources of VOC emissions. Under both scenarios, we assumed the maximum possible methane reductions that could be associated with standards for VOC.

Our calculations from extending subpart OOOO assumed that liquids unloading events and oil well *completions* should be considered well modifications, and therefore should be fully covered consistent with our recommendations elsewhere in this report. We determined that rule could potentially achieve a methane abatement co-benefit of 209,000 to 354,000 tons methane.

For the remaining emissions sources (aside from liquids unloading and oil well completions), we include abatement under a CTG rule, which only includes abatement from facilities located in nonattainment areas (NAAs). We used data collected from HPDI with the assistance of the Environmental Defense Fund to estimate oil and gas activity in these areas and estimate potential abatement using these factors. For all wells with production in 2013, 9 percent of wells, 7 percent of oil production, and 9 percent of gas production occurred at wells in these NAAs (mostly in California). Approximately 8 percent of gas processing plants are located in these areas. We start with the abatement potential for each source that are detailed in this report, and then we multiply by these factors. There is a potential methane abatement co-benefit of 118,000 to 129,000 tons methane from a CTG rule.

Together, we estimated that VOC rules could potentially reduce methane emissions as a co-benefit by between 327,000 and 484,000 metric tons.

Emissions Source	Industry Segment	Scaling Method	Scaling Factor
Leaks	Oil and Gas Production	Scaled to well count	9%
	Processing	Scaled to processing plants	8%
Compressors	Gas Production	Scale to gas production	9%
	Oil Production	Scale to oil production	7%
	Processing	Scaled to processing plants	8%
Pneumatics	Oil and Gas Production	Scaled to oil and gas production	8%
	Processing	Scaled to processing plants	8%
Oil Wells	Completions	Include all abatement	
	Associated Gas	Scale to oil production	7%
Liquids Unloading		Include all abatement	

Waste Not

Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry

By setting direct standards for methane pollution from the oil and gas industry, EPA can dramatically reduce harmful, wasteful methane pollution, protect public health, improve air quality, and combat global warming. Proven, low-cost technologies and practices are available today that can cut methane pollution from this industry by half, saving the amount of gas used to heat at least three million homes.

Clean Air Task Force
18 Tremont Street, Suite 530
Boston, MA 02108
www.catf.us

Natural Resources Defense Council
40 West 20th Street
New York, NY 10011
www.nrdc.org

Sierra Club
85 Second Street, 2nd Floor
San Francisco, CA 94105
www.sierraclub.org

Earthjustice, Earthworks and the Environmental Defense Fund have reviewed this report and support the findings and recommendations.

This report is available online at *http://catf.us/resources/publications/view/205*.