Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries

March 2014

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Acknowledgement

ICF received and considered data and commentary from numerous stakeholder organizations, including oil and gas producers, pipelines, equipment vendors, service providers, and a trade organization. No information in this report should be attributed to any single organization, as all data is aggregated from multiple sources and often uses average values. Furthermore, acknowledgement of industry participation does not imply their agreement with the study conclusions, which reflect the professional judgment of ICF.

We thank all of the stakeholder organizations for providing input to this study, and specifically acknowledge the following entities: Anadarko Petroleum, BG Group, Pioneer Natural Resources, Southwestern Energy, and the American Gas Association.

Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AEO	Annual Energy Outlook
BAMM	Best Available Monitoring Methods
bbl	Barrel
Bcf	Billion Cubic Feet
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
CapEx	Capital Expenditures
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DI&M	Directed Inspection and Maintenance
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
HAP	Hazardous Air Pollutant
hp	Horsepower
IR	Infrared
LDAR	Leak Detection and Repair
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
MAC	Marginal Abatement Cost
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
$MMTCH_4$	Million Metric Tonnes Methane

Acronym / Abbreviation	Stands For
$MMTCO_2e$	Million Metric Tonnes CO_2 equivalent
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPV	Net Present Value
NSPS	New Source Performance Standards promulgated under the Federal Clean Air Act
OpEx	Operating Expenditures
PRO	Partner Reported Opportunity
psig	Pounds per Square Inch – Gauge
RECs	Reduced Emission Completions
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
TEG	Triethylene Glycol
TSD	Technical Support Document
USD	U.S. Dollars
VOC	Volatile Organic Compound
VRU	Vapor Recovery Unit

1. Executive Summary

Methane is an important climate change forcing greenhouse gas (GHG) with a short-term impact many times greater than carbon dioxide. Methane comprised 9% of U.S. greenhouse gas (GHG) emissions in 2011 according to the U.S. EPA Inventory of US Greenhouse Gas Emission and Sinks: 1990-2011[1], and would comprise a substantially higher portion based on a shorter timescale measurement. Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change[2]. Emissions from the oil and gas industry are among the largest anthropogenic sources of U.S. methane emissions. At the same time, there are many ways to reduce emissions of fugitive and vented methane from the oil and gas industry and, because of the value of the gas that is conserved, some of these measures actually save money or have limited net cost.

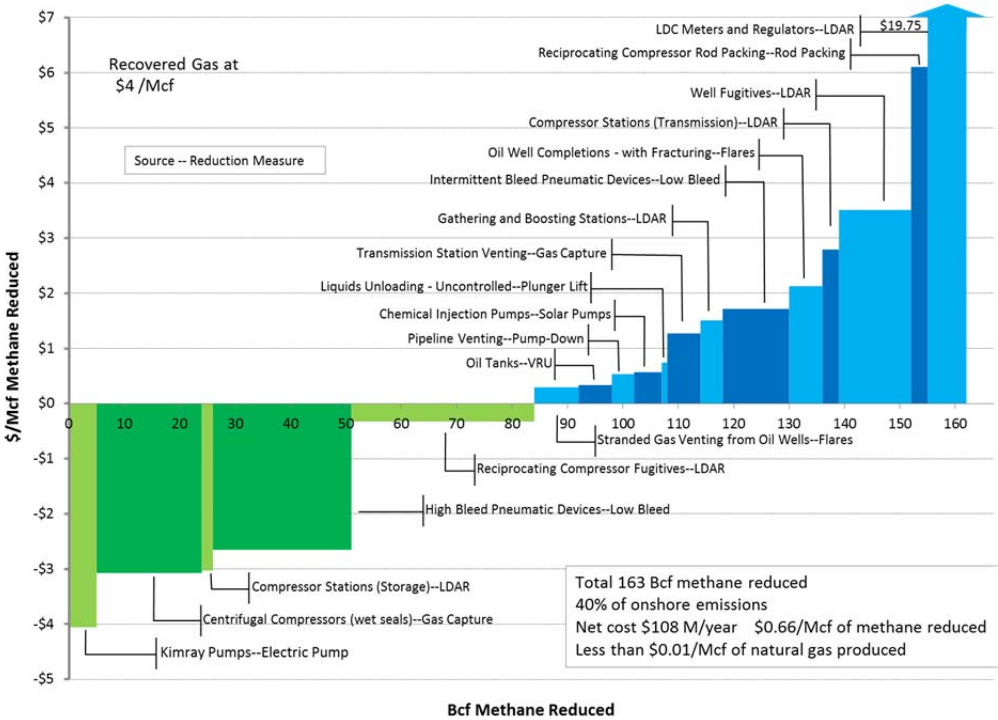
Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the oil and natural gas industries to identify the most cost-effective approaches to reduce these methane emissions. The study projects the estimated growth of methane emissions from these industries through 2018 as a future date at which new emission reduction technologies could be installed. It then identifies the largest emitting segments and estimates the magnitude and cost of potential reductions achievable through currently available technologies. The key conclusions of the study include:

- **Emission Growth** - Methane emissions from oil and gas activities are projected to grow 4.5% from 2011 to 2018 including reductions from EPA regulations adopted in 2012 (known as New Source Performance Standards (NSPS) Subpart OOOO). All of the projected net growth is from the oil sector, largely from flaring and venting of associated gas. Growth from new natural gas sources is offset by the NSPS and other continuing emission reduction activities. Nearly 90% of the emissions in 2018 come from existing sources (sources in existence in 2011).
- **80/20 Rule for Sources** - 22 of the over 100 emission source categories account for over 80% of the 2018 emissions, primarily at existing facilities.
- **Abatement Magnitude and Economics** - A 40% percent reduction in onshore methane emissions is projected to be achievable with existing technologies and techniques at a net total cost of $0.66/Mcf of methane reduced, or less than $0.01/Mcf of gas produced, taking into account savings that accrue directly to companies implementing methane reduction measures (Figure 1-1). If the full economic value of recovered natural gas is taken into account, including savings that do not directly accrue to companies implementing methane reduction measures, the 40% reduction is achievable

[1] Calculated at a 100 year GWP of 21 – see Section 2.3.
[2] Shoemaker, J. et. al., "What Role for Short-Lived Climate Pollutants in Mitigation Policy?". Science Vol 342 13 December 2013

while saving the U.S. economy and consumers over $100 million per year. The cost for some measures and segments of the industry is more or less than the net total. The initial capital cost of the measures is estimated to be approximately $2.2 billion with the majority of the costs in the oil and gas production segments.

Figure 1-1 - Marginal Abatement Cost Curve for Methane Reductions by Source



- **Abatement Opportunities** – By volume, the largest opportunities target leak detection and repair of fugitive emissions (“leaks”) at facilities and gas compressors, reduced venting of associated gas, and replacement of high-emitting pneumatic devices.
- **Co-Benefits** – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment. The methane reductions projected here would also result in a 44% reduction in volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) associated with methane emissions from the oil and gas industry.

There are several caveats to the results:

- The 2011 EPA inventory is the best starting point for analysis, but it is based on many assumptions and some older data sources. Although the inventory is improving with new data, it is designed to be a planning and reporting document and is imperfect, especially at the detailed level, for a granular analysis of this type.
- Emission mitigation cost and performance are highly site specific and variable. The values used here are estimated average values.

- The analysis presents a reasonable estimate of potential cost and magnitude of reductions within a range of uncertainty.

2. Introduction

Methane emissions have an enhanced effect on climate change because methane has a climate forcing effect 25 times greater on a 100 year basis than that of carbon dioxide, the primary greenhouse gas (GHG). Methane's impact is almost three times greater on a 20 year basis and there is research that may cause both factors to be increased. (See Section 2.3) Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change.

Emissions from the oil and gas industries are among the largest anthropogenic sources of U.S. methane emissions according to the U.S. EPA Inventory of U.S. Greenhouse Gas Emissions[3], and recent analyses indicate that the EPA inventory estimates may understate total methane emissions from this source category[4]. At the same time, there are many ways to reduce emissions of fugitive and vented methane from the oil and gas industries and, because of the value of the gas that is conserved, some of these measures actually save money or have limited net cost.

Companies in the oil and gas industries have made significant voluntary reductions in methane emissions. However, voluntary adoption of control techniques is uneven. The U.S. has established emission regulations for conventional pollutants (NSPS Subpart OOOO and oil and gas NESHAPS) that will have the effect of significantly reducing methane emissions from certain new sources in some segments of the gas industry. Some states also have proposed or established regulations that limit methane emissions from the oil and gas industry. However, these regulations generally do not apply to emissions from the existing infrastructure, so there is a large population of uncontrolled sources. Overall, methane emissions are significant and there is a sizeable potential for additional cost-effective reduction opportunities.

2.1. Goals and Approach of the Study

Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the oil and natural gas industry. This ICF analysis is solutions-oriented and complements EDF's ongoing work on methane emissions in the oil and natural gas sectors. The approach to the study was to:

- Define a baseline of methane emissions from the oil and gas sectors. The baseline was established for 2018 as a conservative estimate of a point when new mitigation technologies could have been installed.

[3] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2011". April 2013. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html Based on a 100 year GWP of 21 – see Section 2.3
[4] Brandt, A. et. al., "Methane Leaks from North American Natural Gas Systems". Science VOL 343 14 February 2014

- Review existing literature and conduct further analysis to identify the largest reduction opportunities and validate and refine cost-benefit estimates of mitigation technologies.
- Conduct interviews with industry, technology innovators, and equipment vendors with a specific focus to identify additional mitigation options.
- Use this information to develop marginal abatement cost (MAC) curves for methane reductions in these industries.
- Document and present the results.

The final outputs of the study include:

- The projected 2018 emissions baseline. (Chapter 3 and Appendix C)
- Inventory of methane mitigation technologies. (Chapters 3 and 6 and Appendix D)
- Emissions abatement cost curves across a range of scenarios (Chapter 4 and Appendix A)
- In-depth case studies of two specific methane mitigation options. (Chapter 5)
- Conclusions (Chapter 6)

2.2. Overview of Gas Sector Methane Emissions

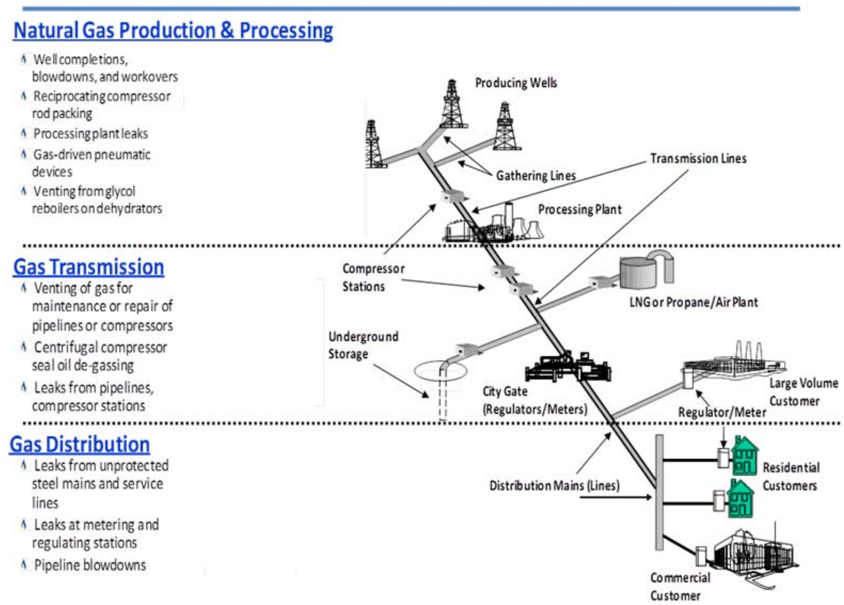
There are many sources of methane emissions across the entire oil and gas supply chain. These emissions are characterized as either:

- Fugitive emissions – methane that “leaks” unintentionally from equipment such as from flanges, valves, or other equipment.
- Vented emissions – methane that is released due to equipment design or operational procedures, such as from pneumatic device bleeds, blowdowns, incomplete combustion, or equipment venting.

Although ‘leaks’ is sometimes used to refer to all methane emissions from the oil and gas industry, we use the more narrow technical definitions in this report.

Figure 2-1 illustrates the major segments of the natural gas industry and examples of the primary sources of methane emissions as gas is produced, processed, and delivered to consumers. Natural gas is produced along with oil in most oil wells (as “associated gas”) and also in gas wells that do not produce oil (as “non-associated gas”). Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental and northeastern shale plays have been a growing source of oil and gas supply.

Figure 2-1 - Natural Gas Industry Processes and Example Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program

Raw gas (including methane) is vented at various points during the production process. Gas can be vented when the well is “completed” at the initial phase of production. Further, because gas wells are often in remote locations without electricity, the gas pressure is used to control and power a variety of control devices and on-site equipment, such as pumps. These pneumatic devices typically release or “bleed” small amounts of gas during their operation. In both oil and gas production, water and hydrocarbon liquids are separated from the product stream at the wellhead. The liquids release gas, which may be vented from tanks unless it is captured. Water is removed from gas stream by glycol dehydrators, which vent the removed moisture and some gas to the atmosphere. In some cases, the gas released by these processes and equipment may be flared rather than vented, to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a significant but less potent GHG than methane, but no flare is 100% efficient, and some methane is emitted during flaring. In addition to the various sources of vented emissions, the many components and complex network of small gathering lines have the potential for fugitive emissions.

Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. The gathering system has pneumatic devices and compressors that vent gas as well as potential fugitive emissions. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. Such plants are another source of fugitive and vented emissions.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the "city gate" hub and then to consumers. The vast majority of the compressors that pressurize the pipeline to move the gas are fueled by natural gas, although a small share is powered by electricity. Compressors emit CO_2 and methane emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission.

Some power plants and large industrial facilities receive gas directly from transmission pipelines, while others as well as residential and commercial consumers have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment. This is especially true for older systems that have cast iron distribution mains.

Many of the emission sources from domestic oil production are similar to those in gas production – completion emissions, pneumatic devices, processing equipment and engine/compressors. Crude oil contains natural gas and the gas is separated from the oil stream at the wellhead and can be captured for sale, vented, or flared. Venting or flaring is most common in regions that do not have gas gathering infrastructure. This is the case currently in North Dakota, where rapid growth in oil production has taken place in a region with little gas gathering infrastructure. While new gathering lines are being built, production is still ahead of the gathering capacity, resulting in continued flaring.

Oil is taken from the wellhead in electric-powered pipelines and more recently by rail, to refineries for processing. Petroleum products are then taken to consumers by pipeline, truck, rail, or barge. The downstream methane emissions in the petroleum sector are much smaller than in the gas sector as most of the methane has been removed from the oil by this point.

For the last 100 years, domestic oil production has been primarily in the Southwest (Texas, Arkansas, Oklahoma), the Gulf of Mexico, California, and Alaska. Domestic gas production has been mostly in the Southwest, Gulf of Mexico, and the Rockies. More recently, the focus of new natural gas and oil development has been in the extraction of gas from shale formations. Shale is a sedimentary rock composed of compacted mud, clay and organic matter. Over time, the organic material can produce natural gas and/or petroleum, which can slowly migrate into formations where it can be recovered from conventional oil and gas wells. The shale rock itself is not sufficiently permeable to allow the gas to be economically recovered through conventional wells; that is, gas will not flow sufficiently freely through the shale to a well for production.

Gas and oil from shale formations is recovered by hydraulically fracturing the shale rock to release the hydrocarbons. This involves pumping water and additives at high pressure into the well to "fracture" the shale, creating small cracks that allow the gas and/or oil to flow out. When the water "flows back" out of the well, methane is entrained and may be vented. Due to the high global warming potential of methane, this can be a large source of GHGs. For these reasons, the increased production of shale gas is a potential source of increased GHG emissions.

Federal regulations promulgated in 2012 require the majority of new hydraulically fractured gas wells to capture or flare the flow-back gas. These regulations and other federal and state regulations also require control of other methane-emitting processes, though many apply only to new sources and to those wells that primarily produce natural gas rather than wells that primarily produce oil, so there remains a large population of existing uncontrolled sources.

Significant amounts of both oil and gas are produced from offshore facilities. While these facilities report significant methane emissions, the reports do not have the detail and specificity of the rest of the methane inventory and therefore cannot be included in the same methodology applied to the rest of the inventory for this analysis. Therefore, this study focuses only on onshore oil and gas industry operations. Additional study of offshore emissions and reduction opportunities would be a useful follow-up to this analysis.

2.3. Climate Change-Forcing Effects of Methane

Different greenhouse gases persist in the atmosphere for different lengths of time and have different warming effects, and thus have different effects on climate change. In order to compare them, the scientific community uses a factor called the global warming potential (GWP), which relates each GHG's effect to that of CO_2, which is assigned a GWP of 1. The science and policy communities have historically looked to the Intergovernmental Panel on Climate Change (IPCC) assessment reports as the authoritative basis for GWP values. The currently accepted values are from the IPCC Fourth Assessment report[5] (AR-4).

CO_2 emissions determine the amount of climate change over the long term, due to their long lifetime in the atmosphere. Because stabilizing climate will require deep cuts in CO_2 emissions, GWP values are most commonly expressed on a 100-year time horizon. On a 100-year basis, methane is assigned a GWP of 25 by the AR-4. This means that one ton of methane has the same effect as 25 tons of CO_2 over 100 years. The 100 year GWP is the standard value used by the EPA and other federal, state, and international agencies to measure GHG emissions. (One exception is the EPA GHG inventory, which uses a 100 GWP of 21, as specified by the United Nations Framework Convention on Climate Change (UNFCC) inventory protocol.)

[5] IPCC. Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. (Cambridge University Press and New York, NY, Cambridge, United Kingdom, 2007).

Some GHGs, including methane, have a stronger climate-forcing effect than CO_2 but a shorter lifetime in the atmosphere (12 years for methane). In order to evaluate the short-term effects, the GWP is also calculated on a 20 year basis. On a 20 year basis, the AR-4 assigns methane a GWP of 72. The IPCC is currently preparing a Fifth Assessment Report (AR-5)[6]. The first phase of that work has adopted higher GWP values due to updated data on methane's role in the atmosphere. The AR-5 values are a 100 year GWP of 28 and a 20 year GWP of 84 for methane. In summary:

- The EPA GHG inventory uses a 100 year GWP of 21.
- Most other regulations and inventories (including the EPA Greenhouse Gas Reporting rule as of 2013) use the AR-4 100 year GWP of 25. The AR-4 20 year GWP is 72.
- The GWPs being put forth in the AR-5 are 28 for 100 years and 84 for 20 years.
- This report uses the AR-4 100 year GWP of 25 except where otherwise noted.

2.4. Cost-Effectiveness of Emission Reductions

It is common in discussing emission reductions to describe "cost-effective" emission reductions. However, there are three different concepts of cost effectiveness that must be understood and differentiated.

The first concept is cost-effectiveness for the company implementing the measure. In this case, "cost-effective" means that the value of gas that is recovered through a methane reduction measure exceeds the incremental capital and operating cost of the measure sufficiently to create a payback or rate-of-return that meets the company's investment criteria. Measures that meet these criteria might be described as having a positive net present value (NPV), a short payback period, or an internal rate of return that meets a certain threshold.

In order for a measure to meet this cost-effectiveness criterion, the measure must recover the methane emissions and be able to recover their monetary value. Flaring of methane emissions does not meet this criterion, for example. In addition, the company must be able to monetize the value of the recovered methane. For example, if a producer reduces methane losses, it will have more gas to sell and will receive an economic benefit.

The second concept is cost-effectiveness at the economy-wide scale. In segments in which the company owns the gas, such as oil and gas production, the company can clearly monetize the value of reduced gas losses. This is also true in some other sectors. Most midstream companies (gathering, processing,

[6] IPCC. "Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change". (Cambridge University Press and New York, NY, Cambridge, United Kingdom, 2013).

storage) are paid a fixed fee for gas lost and consumed during their operations. If they can reduce their losses then they will benefit directly from the reduced losses.

Although transmission and local distribution companies typically have a similar cost structure, they are usually required by regulators to return the value of reduced losses to their customers, so they cannot recover the benefit of reduced methane losses. Methane reductions in these segments of the industry will not have a positive return to the company or be "cost-effective" in this sense. That said, the value of reduced losses will accrue to other parts of the economy. If a pipeline or LDC reduces its losses, the benefit will eventually flow through to the customers and to the economy overall. Reduced losses will eventually flow through as lower prices for gas delivery and delivered cost of gas to consumers. Thus, even when the entity implementing a reduction cannot directly benefit from reduced losses, there is a broader benefit and that full economic benefit can be calculated and allocated against the cost of the methane reduction, the second kind of cost-effectiveness.

The last concept of cost-effectiveness is in the context of pollution control programs. In conventional pollution control programs the control technology rarely results in a cost reduction to the company that is required to implement it. That is, the cost-of-control is almost always positive and the net present value is negative and there is no payback for the investment. Nevertheless, these programs incorporate the concept of cost-effectiveness, meaning that the cost is acceptable to society as a means of meeting public health and environmental goals. The cost-effectiveness varies for different pollutants and different regulatory programs. For example, $10,000/ton of VOC reduced may be considered cost-effective in some ozone non-attainment areas while $100/ton of SO_2 may be considered cost-effective for an acid rain reduction program. In this context, methane reductions can be considered cost-effective even if they have a net cost to the company or society overall. Where methane reductions do create a net value to the implementing company, the cost-of-control will be negative, i.e., the company is reducing emissions and saving money rather than spending money.

In this study, the value of recovered gas is included in calculating the cost-effectiveness of mitigation measures where the gas can be recovered and where it can be monetized by the company. Therefore, the same measure may have different costs for different segments, e.g., reducing compressor emissions will have a lower net cost in the production segment than in the transmission segment. This reflects the net cost to the company to implement the measure. However, where gas can be recovered through a mitigation measure, it will have value to the broader economy, even if it is not recognized by the company that must make the investment. Therefore we also show, in certain cases, an economy-wide cost-effectiveness measure, which recognizes the value of all recovered gas, even if it cannot be recognized directly by the affected company. These cases are clearly labeled as such. The cost-of-control, whether positive or negative, can be also evaluated in the regulatory sense and compared to other available emission reduction options. Finally, there are additional social and environmental benefits of methane reductions that are not captured in these calculations, including the broader economic value of reduced climate risk and co-benefit reductions of conventional pollutants such as ground-level ozone and hazardous air pollutants.

3. Approach and Methodology

3.1. Overview of Methodology

This section provides an overview of the methodology applied for this study. The major steps were:

- **Establish the 2011 Baseline for analysis** – the analysis started with the most recent U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions published in 2013 with data for 2011[7]. This inventory was reviewed and revised to account for additional, more recent information such as information from the EPA GHG Reporting Program[8] and the University of Texas/EDF gas production measurement study[9]. These changes were applied to develop an ICF 2011 Baseline, which was used as the basis for projecting onshore methane emissions to 2018.
- **Project emissions to 2018** – the analysis of potential reductions was based on the projected 2018 emission level. The year 2018 was chosen as a conservative date by which new control technologies could have been installed. The inventory was also disaggregated from the national level in the EPA inventory to the seven regions used in the U.S. EIA's oil and gas data to provide regional reporting.
- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the projected 2018 inventory and the mitigation options that would be most effective and cost-effective for these sources.
- **Characterization of emission reduction technologies** – a key part of the study was to review and update information on the cost and performance of the selected mitigation technologies. Information was gathered from equipment manufacturers, oil and gas companies, and other knowledgeable parties.
- **Development of the marginal abatement cost curves** – the technology information was applied to the emissions inventory to calculate the potential emission reduction and cost. The results were displayed in a series of marginal abatement cost curves.

The key steps are discussed further in the following sections.

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[7] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2011", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html
[8] http://www.epa.gov/ghgreporting/
[9] Allen, David, et. al., "Measurements of Methane Emissions at Natural Gas Production Sites in the United States". 10.1073/pnas.1304880110

3.2. Development of the 2011 Emissions Baseline

The development of the 2011 Baseline takes as its starting point the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011* published in 2013 with data for 2011[10], specifically the portion on methane from Natural Gas and Petroleum Systems. While the EPA Inventory is the most comprehensive source for this type of information, it is designed to be a planning and reporting tool rather than the basis for this type of granular analysis. Therefore ICF developed a new 2011 Baseline, adapting the EPA structure to the needs of the analysis and incorporating more recent information. This was not a complete update of the inventory, which was beyond the scope of this project, but an update of any sections for which new or better data could be readily identified. The EPA Inventory[11] estimates 436 billion cubic feet (Bcf) or 8.4 million metric tonnes of methane emissions for the petroleum and natural gas sectors including offshore production in 2011. The petroleum and natural gas sectors are then further divided into the various segments for the natural gas sector (Gas Production, Gathering and Boosting, Gas Processing, Gas Transmission, Gas Storage, LNG Import/Export, and Distribution) and the petroleum sector (Oil Production, Transportation, and Refining).

The EPA Inventory breaks out methane emissions for approximately 200 sources, and calculates uncontrolled emissions using activity factors (e.g., equipment counts) multiplied by emission factors (average emissions from each source) to estimate the total emissions. The total uncontrolled emissions are reduced by emission reductions reported primarily from the EPA's voluntary Natural Gas STAR Program, plus additional reductions from other sources, such as state regulations.

The development of the 2011 Baseline relied on the 2011 EPA Inventory and data from several publically available references. The most common source of updated information was the U.S. EPA's mandatory Greenhouse Gas Reporting Rule (GHGRP) subparts C (combustion from stationary sources) and W (methane emissions from petroleum and natural gas systems). ICF also used information and data from the U.S. Energy Information Administration (EIA), EPA's 1996 GRI study of methane emissions[12], the EPA Manual of Emission Factors AP-42[13], various state energy and environmental departments, and the EDF/University of Texas methane measurement study. Much of this information was not available at the time that the 2011 EPA inventory was originally developed.

While some source categories increased and some decreased due to these adjustments, the overall effect was an increase of 2.4% in the net estimated methane emissions from the oil and gas sectors to

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[10] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2011", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

[11] While the 2013 edition of the Inventory was the current version at the time the study was initiated, EPA has since released the draft of the 2014 edition. However this study does not address that newer version of the Inventory.

[12] http://epa.gov/gasstar/tools/related.html under "Methane Emissions from the Natural Gas Industry"

[13] http://www.epa.gov/ttn/chief/ap42/index.html

446 Bcf (8.6 million metric tonnes) of methane. The estimated emissions from the natural gas sector were 2% (10 Bcf) lower while the emissions from the oil sector increased by 26% (20 Bcf) compared to the EPA inventory. Table 3-1 summarizes the emissions in the 2011 Baseline compared to the 2011 EPA Inventory.

The changes by industry segment are shown in Table 3-1.

Table 3-1 - Summary of 2011 Methane Emissions Baseline

Segment	2011 EPA Inventory		ICF 2011 Baseline		Change (%)
	(Million tonnes CH_4)	(Bcf CH_4)	(Million tonnes CH_4)	(Bcf CH_4)	
Natural Gas					
Gas Production	2.2	113	2.0	103	-9%
Gathering and Boosting	0.5	24	0.8	43	80%
Gas Processing	0.9	48	0.8	44	-9%
Gas Transmission	1.7	87	1.4	75	-14%
Gas Storage	0.3	17	0.3	15	-11%
LNG	0.1	5	0.1	6	22%
Gas Distribution	1.3	69	1.3	69	0%
Petroleum					
Oil Production	1.4	72	1.8	92	27%
Oil Transportation	< 0.1	< 1	< 0.1	< 1	1%
Oil Refining	< 0.1	1	< 0.1	1	0%
Total Net Gas Emissions	7.0	362	6.8	353	-2%
Total Net Oil Emissions	1.4	73	1.8	93	26%
Total Emissions	**8.4**	**436**	**8.6**	**446**	**2.4%**

The largest change to the structure of the Natural Gas segment in the 2011 Baseline was breaking out the Gathering and Boosting segment. This is the segment between onshore Production and either Gas Processing or Gas Transmission. This segment is included in the onshore Production segment of the EPA

Inventory based on the 1996 GRI measurement study rather than being fully broken out as a separate segment. In this study, some sources were moved from Production to the Gathering and Boosting segment in order to allow them to be analyzed separately for this segment, and new emissions estimates, for some sources underrepresented in the 2011 EPA inventory, were added. The major source additions were new estimates of compressor and pneumatic device emissions. In addition, emissions from condensate tanks were moved from the Production segment to the Gathering and Boosting segment.

The overall net change to the Natural Gas segment of the U.S. Inventory is a decrease of 2% compared to the EPA Inventory value. This is the net effect of increased estimates for well head fugitives and Gathering and Boosting (for compressors and pneumatic devices) and decreases in the estimates for well completion and workover emissions (based on data and factors from Subpart W) and compressor exhaust emissions. These changes are discussed in Appendix B.

The net change to the Petroleum segment of the 2011 Baseline is 26% higher than the EPA Inventory value. The biggest categories contributing to this increase were the inclusion of stranded gas venting from oil wells and updated estimates of associated gas flaring estimates. All of these changes are discussed in more detail in Appendix B.

3.3. Projection to 2018

The 2018 forecast of natural gas and petroleum systems methane emissions starts with the 2011 Baseline described in Section 3.2. One primary driver for the projecting the 2011 emissions to 2018 was the U.S. EIA's Annual Energy Outlook 2013 and 2014 Early Release. ICF also relied upon a 2011 study for the INGAA Foundation[14] that forecast requirements for selected infrastructure and equipment for the natural gas and petroleum industry. In addition, expected emission reductions as a result of NSPS Subpart OOOO were incorporated into the forecast. Without the NSPS, emissions grow from 446 Bcf in 2011 to 491 Bcf in 2018. With the NSPS adjustments, total emissions are projected to grow by 4.5% to 466 Bcf through 2018. Almost all of this growth is from the oil sector whereas the net emissions for the gas sector are almost unchanged (Figure 3-1). Growth from new sources in the gas sector is offset by NSPS reductions, and reductions from existing sources such as continuing replacement of cast iron mains and turnover of high-emitting pneumatic devices. Despite the overall growth, nearly 90% of the emissions in 2018 come from existing sources (sources in place as of 2011) as shown in Figure 3-2.

[14] *North American Midstream Infrastructure Through 2035 – A Secure Energy Future, Prepared for the INGAA Foundation*, ICF International, 2011.

Figure 3-1 – Emission Projection to 2018 – (Including Offshore)

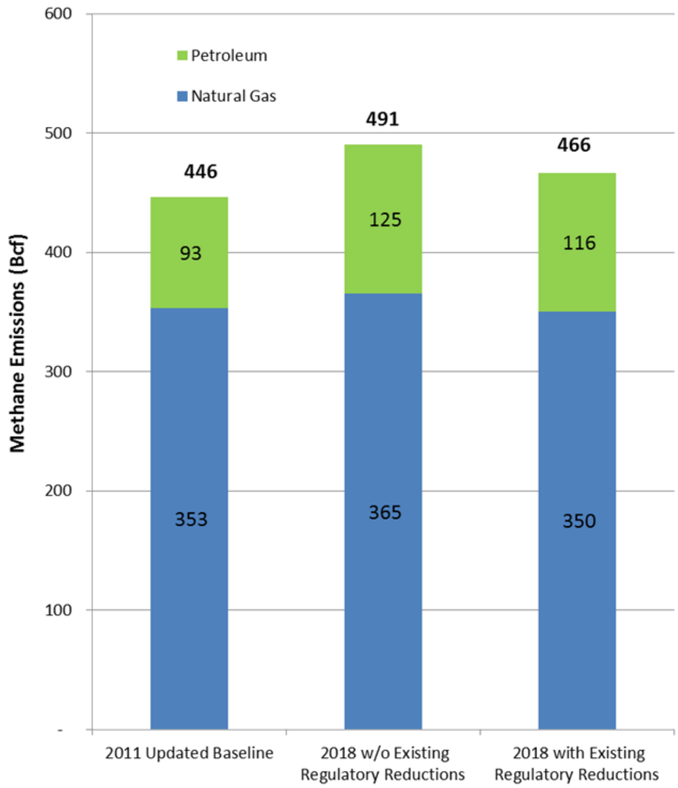
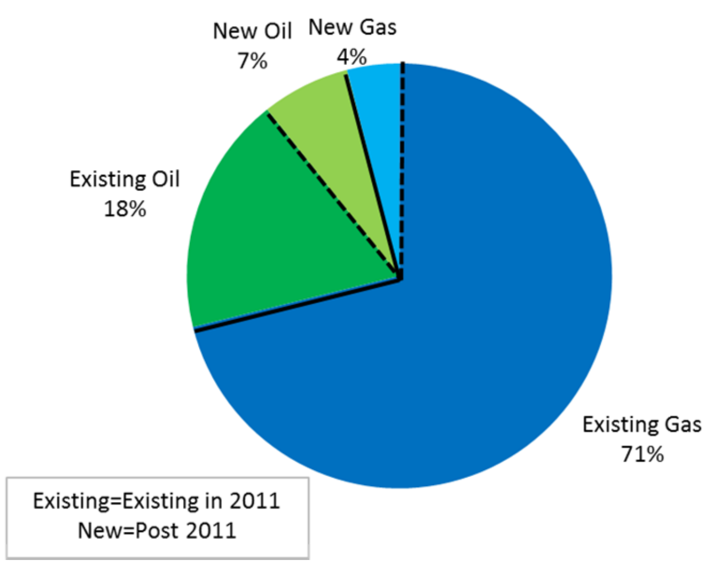


Figure 3-2 - Distribution of Emissions in 2018



The projection also disaggregated the national level emissions estimate of the 2011 inventory to regions used by the EIA to report oil and gas data (Figure 3-3). The details of the analysis are discussed in Appendix C.

Figure 3-3 - EIA Oil and Gas Regions

3.4. Identification of Targeted Emission Sources

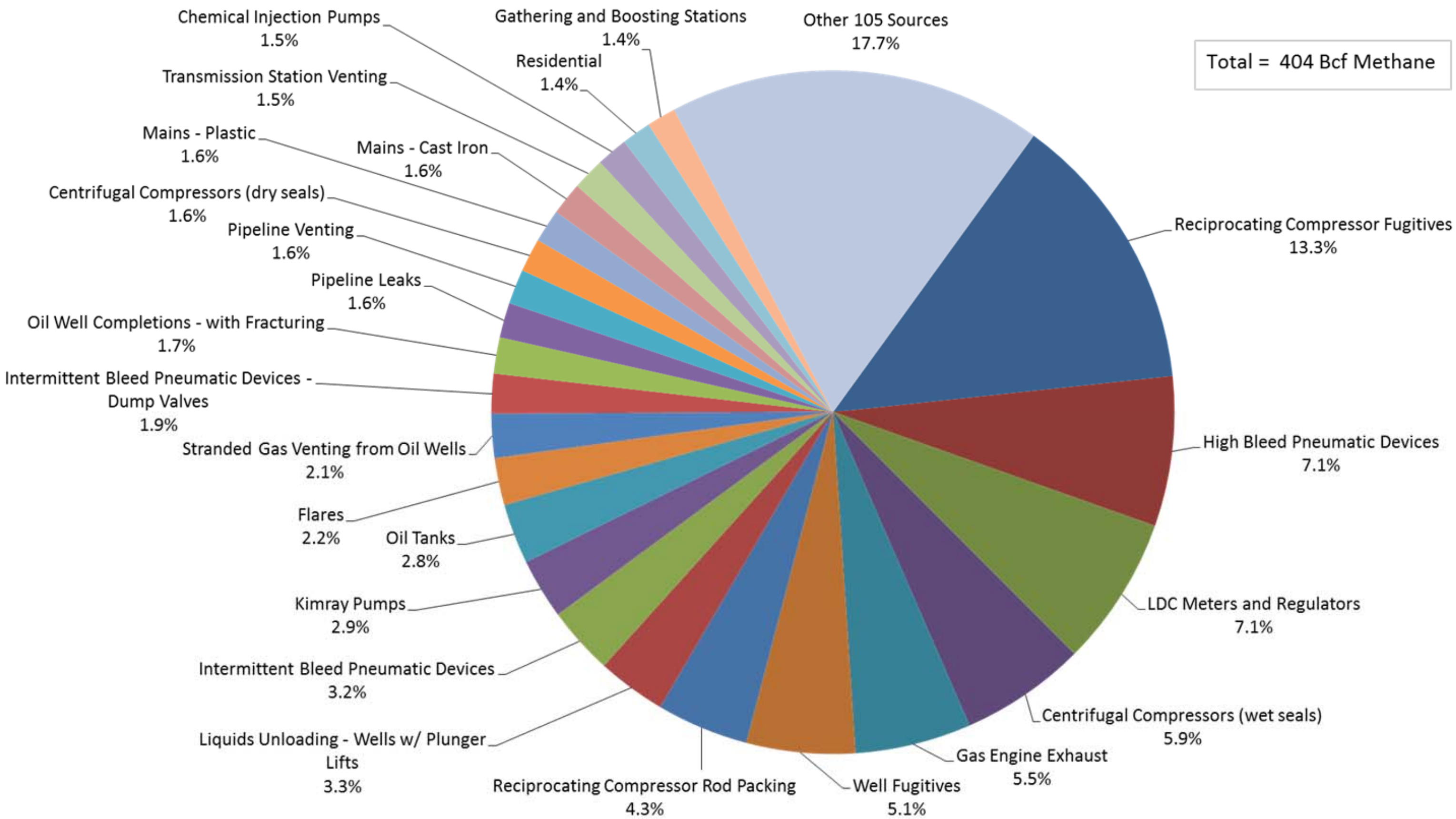
Table 3-2 summarizes the largest emitting source categories in the projected 2018 emissions for the oil and gas sectors by major source category. Due to the lack of specific data on the emission sources for offshore oil and gas production, the study focused on onshore production and offshore emissions are excluded from this list. The top 22 source categories account for 80% of the total 2018 onshore methane emissions of 404 Bcf and the remaining 100+ categories account for 1% or less of the total emissions each. Although these source categories were not included in this analysis due to their small size, there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of them.

Figure 3-4 shows the distribution of sources graphically. Fugitive emissions are the largest emission source category overall. Vented emissions from pneumatic controllers and pumps are also significant as is vented associated gas from oil well completions and production. Venting from wet seal centrifugal compressors is also a large source.

Table 3-2 - Highest Emitting Onshore Methane Source Categories in 2018

Source	2018 Emissions (Bcf)	Percent of Total	Cumulative Bcf	Cumulative %
Reciprocating Compressor Fugitives	53.8	13%	53.8	13%
High Bleed Pneumatic Devices	28.7	7%	82.5	20%
LDC Meters and Regulators	28.7	7%	111.2	28%
Centrifugal Compressors (wet seals)	24.0	6%	135.3	33%
Gas Engine Exhaust	22.2	5%	157.5	39%
Well Fugitives	20.8	5%	178.3	44%
Reciprocating Compressor Rod Packing	17.6	4%	195.9	48%
Liquids Unloading - Wells w/ Plunger Lifts	13.2	3%	209.1	52%
Intermittent Bleed Pneumatic Devices	13.0	3%	222.1	55%
Kimray Pumps	11.5	3%	233.6	58%
Oil Tanks	11.5	3%	245.1	61%
Flares	9.0	2%	254.1	63%
Stranded Gas Venting from Oil Wells	8.4	2%	262.5	65%
Intermittent Bleed Pneumatic Devices - Dump Valves	7.7	2%	270.2	67%
Oil Well Completions - with Fracturing	6.9	2%	277.1	69%
Pipeline Leaks (All)	6.7	2%	283.8	70%
Pipeline Venting (Transmission)	6.6	2%	290.4	72%
Centrifugal Compressors (dry seals)	6.4	2%	296.8	73%
Mains – Plastic	6.3	2%	303.2	75%
Mains - Cast Iron	6.3	2%	309.4	77%
Transmission Station Venting	6.2	2%	315.7	78%
Chemical Injection Pumps	5.9	1%	321.6	80%
Residential	5.6	1%	327.2	81%
Gathering and Boosting Stations	5.6	1%	332.8	82%

Figure 3-4 - 2018 Projected Onshore Emissions



3.5. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories. Some of the most significant measures are discussed in greater detail in Appendix D. Much of the cost and performance data for the technologies is based on information from the EPA Natural Gas STAR program[15] but has been updated and augmented with information provided by industry and equipment vendor sources consulted during this study. The discussion is organized according to the emission source and mitigation option.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data. The costs and performance of an actual individual project may not be directly comparable to the averages employed in this analysis because implementation costs and technology effectiveness are highly site specific. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

Fugitive Emissions – Fugitive emissions are the unplanned loss of methane from pipes, valves, flanges, and other types of equipment. Fugitive emissions from reciprocating compressors, compressor stations (transmission, storage, and gathering), wells, and LDC metering and regulator equipment are the largest combined emission category, accounting for over 120 Bcf, or 30% of the highlighted sources.

Leak Detection and Repair (LDAR) is the generic term for the process of locating and repairing these fugitive leaks. There are a variety of techniques and types of equipment that can be used to locate and quantify these fugitive emissions. Extensive work has been done by EPA and others to document and describe these techniques, both in the Gas STAR reference materials and in several regulatory analyses.

The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site. LDAR programs have been analyzed for several recent regulatory initiatives, including for the EPA's NSPS Subpart OOOO[16] and the current proposed revisions to the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)[17]. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD) [18] for NSPS Subpart OOOO as the basis for cost and reduction effectiveness calculations.

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[15] http://www.epa.gov/gasstar/
[16] http://www.epa.gov/airquality/oilandgas/
[17] http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820
[18] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards". http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

The key factors in the analysis are how much time it takes an inspector to survey each facility, how many inspections are required each year, how much reduction can be achieved, and how much time is required for repairs. Research cited by both Colorado and EPA indicates that more frequent inspections result in greater reductions, summarized as approximately:

- Annual inspection = 40% reduction
- Quarterly inspection = 60% reduction
- Monthly inspection = 80% reduction

ICF adapted the Colorado analysis, which calculates the capital and labor cost to field a full-time inspector, including allowances for travel and record-keeping (Table 3-3). ICF added additional time for training. The capital cost includes an infrared camera (which is used to locate fugitive emissions) a truck and the cost of a record-keeping system. The combined hourly cost was the basis for the cost estimates.

Table 3-3 - LDAR Hourly Cost Calculation

Labor			Capital and Initial Costs	
Inspection Staff	$75,000		Infrared Camera	$122,200
Supervision (@ 20%)	$15,000		Photo Ionization Dector	$5,000
Overhead (@10%)	$7,500		Truck	$22,000
Travel (@15%)	$11,250		Record keeping system	$14,500
Recordkeeping (@10%)	$7,500		Total	$163,700
Reporting (@10%)	$7,500			
Fringe (@30%)	$22,500		Training Hours	80
Subtotal Costs	**$146,250**		Training Dollars	$6,223
Hours/yr	1880		Amortized Capital +Training	$44,825
Hourly Labor Rate	**$77.79**		Annual Labor	$146,250
			Annual Total Cost	**$191,075**
			Total Cost as Hourly Rate	**$101.64**

Many analyses have used facility component counts and historical data on the time required to inspect each component to estimate facility survey times. However, the use of the infrared camera technology allows much shorter survey times[19] and the EPA and Colorado time estimates have been criticized as too long. The estimates here are based on experience with the infrared camera and are shorter than the Colorado and EPA estimates that based on component counts.

ICF then adopted the baseline emission values for wells, gathering and transmission stations, and processing stations from the EPA analysis. EPA includes three well pad sizes with different baseline emissions. The EPA analysis did not provide estimates of the distribution of the three sizes for existing facilities so the middle estimate was used for this analysis. Using the smaller and larger well pad emission estimates would result in higher and lower emission reduction costs respectively.

For LDCs, the analysis only includes large meter and regulator facilities. Smaller facilities had a much higher cost due to the small baseline emissions. The LDC costing was done using the same operator and capital costs as for the upstream and midstream facilities. The baseline emission factors for LDCs were adapted from an EPA Gas STAR document[20] which found that on average two 100 Mcf/year leaks were found at 50% of the facilities and the leaks were reduced by 50% through the program.

Table 3-4 summarizes the assumptions for the overall LDAR calculation. This analysis assumes quarterly emission surveys for all facilities. The reduction is assumed to be 60%, which is consistent with data presented in the NSPS TSD and Colorado analysis. In addition to the surveys, the estimate includes one initial visit to each site to inventory the equipment (equivalent hours to two inspection visits for each site with cost averaged over five years) and additional visits for repairs. Gas processing plants are already subject to some LDAR requirements for conventional pollutants, which result in co-benefit methane reductions. The miscellaneous fugitive emissions for gas processing were below the size threshold for this analysis but the costs developed here for gas processing are applied to compressors in that segment.

Some repairs can be made at the time of the survey, such as tightening valve packing or flanges but others will require additional repair time. This analysis assumes repair time equivalent to three survey visits for each facility for repairs each year. The capital cost of larger repairs is not included on the assumption that these repairs would need to be made anyway and the LDAR program is simply alerting the operator to the need. The time for repairs is consistent with the low end of the Colorado analysis that was derived based on component counts and leak rates. This lower repair estimate takes into account that:

- These are average values across facilities – not every facility will require repairs.

[19] Robinson, D, et. al., "Refinery Evaluation of Optical Imaging to Locate Fugitive Emissions". Journal of the Air & Waste Management Association. Volume 57 June 2007.

[20] EPA Gas STAR "Directed Inspection and Maintenance at Gate Stations and Surface Facilities". http://epa.gov/gasstar/documents/ll_dimgatestat.pdf

- These are average values over time – not every facility will need repairs every year while being monitored on a continuing basis.
- Some or all of cost of major repairs is assumed to be part of regular facility maintenance.

Table 3-4 – Cost Calculation – Quarterly LDAR

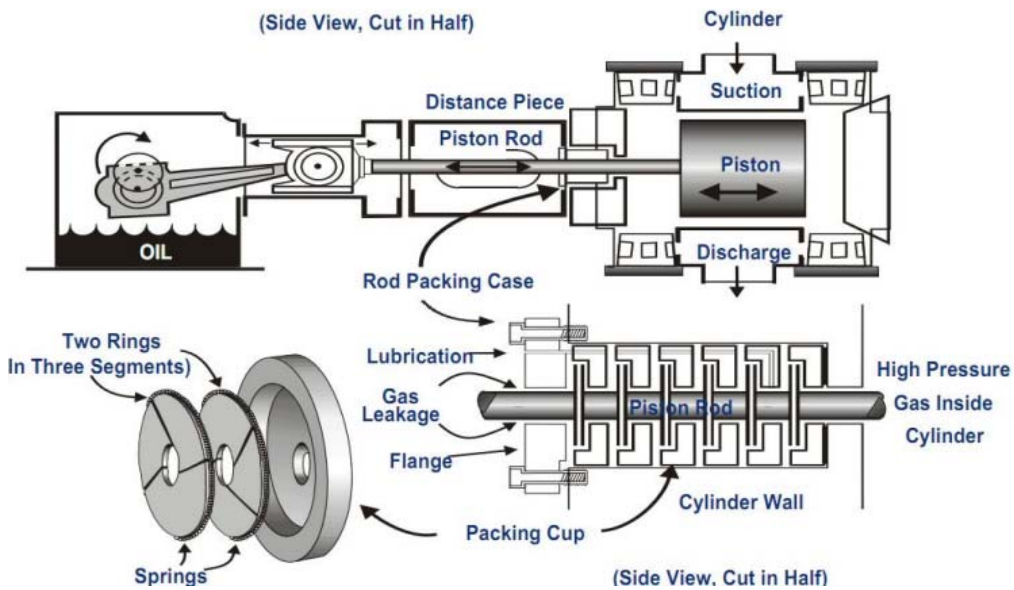
	Well Pads	Gathering	Processing	Transmission	LDC
Methane Mcf/yr	440	1,676	2,448	4,671	150
% Reduction	60%	60%	60%	60%	60%
Reduction Mcf	264	1,006	1,469	2,803	90
Hours each Inspection	2.7	8	8	8	2
Frequency (per year)	4	4	4	4	4
Annual Inspection Cost	$1,084	$3,252	$3,252	$3,252	$813
Initial Set-Up	$108	$325	$325	$325	$81
Repair Labor Cost	$813	$2,439	$2,439	$2,439	$407
Total Cost/yr	$2,006	$6,017	$6,017	$6,017	$1301
Recovered Gas Value*	$1,340	$5,105	$7,455	$12,416	$399
Net Cost	$666	$912	-$1,438	-$6,399	$902
Cost of Reduction ($/Mcf methane reduced)					
Without Gas Credit	**$7.60**	**$5.98**	**$4.10**	**$2.15**	**$14.45**
With Gas Credit	**$2.52**	**$0.91**	**-$0.98**	**-$2.28**	**$10.03**

*Gas at $4/Mcf

The value of reduced gas losses is credited to the program for the upstream segments. These final reduction cost values were used for the analysis.

Reciprocating Compressor Rod Packing – Reciprocating compressors are used in most segments of the natural gas and oil industry, though much less commonly in local gas distribution than in other segments. Rod packing systems are used to maintain a seal around the piston rod, minimizing the leakage of high pressure gas from the compressor cylinder, while still allowing the rod to move freely (Figure 3-5). However, some gas still escapes through the rod packing, and this volume increases as the packing wears out over time, potentially to many times the initial leak rate. There is no standard optimum interval to replace the rod packing, but the NSPS Subpart OOOO requires rod packing in new reciprocating compressors in the production and processing sectors to be replaced every 26,000 hours of operation (approximately every three years).

Figure 3-5 - Reciprocating Compressor Rod Packing



Industry reports that the rod packing for compressors at gas processing plants and some transmission stations is routinely replaced at least that frequently as part of routine maintenance. However, it is believed that rod packing in the production and gathering and boosting sectors is replaced less frequently. This is due, in part, to several factors, including the remote location of these compressors, the lack of a back-up compressor for use during compressor downtime, and because many of the compressors in these sectors are leased rather than owned. This analysis assumes a requirement to replace rod packing for all reciprocating compressors every 26,000 hours of operation.

Gas STAR data[21] indicate that rings (the compressor packing) cost between $300 and $600 per cylinder and $1,000 to $2,500 per compressor to install. Industry sources for this study put the cost at $5,000 per cylinder, which was adopted for this analysis. The Technical Support Document (TSD) for NSPS Subpart OOOO provides a detailed analysis of rod packing replacement. The emissions from new rod packing are estimated in the TSD at 11.5 standard cubic feet per hour (scfh). Baseline emissions for rod packing are estimated at approximately 57 scfh, however the age of the packing at that time is not stated. There is little data on the emissions from rod packing over time but reductions for this mitigation option come from replacing the rod packing at a shorter interval than currently being practiced at given facility.

[21] "Reducing Methane Emissions From Compressor Rod Packing Systems" http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

For this analysis it was assumed that the facility currently replaces the rod packing every five years and that the interval is reduced to three years (26,000 hours). It was assumed that the new rod packing emits 11.5 scfh and the emissions increase linearly to 57 scfh after three years and increase linearly thereafter. Comparing the emissions under this scenario for 15 years, the three year replacement schedule would emit 35% less than the five year replacement schedule. In addition, the cost of rod packing replacement would be 66% greater for the three year replacement schedule than the five year schedule. As noted above, it was assumed that rod packing is already changed on this schedule in many processing plants and some transmission stations, so the applicability was reduced to 25% for processing and 70% for transmission, storage and LNG. The assumptions are summarized in Table 3-5.

Table 3-5 - Assumptions for Rod Packing Replacement

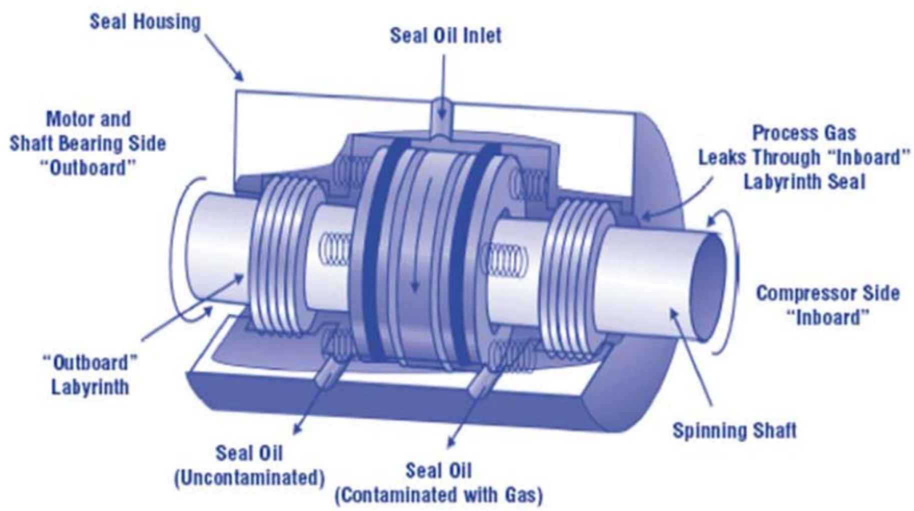
Capital Cost per Compressor	Percent Reduction	Mcf Reduced/year	Lifetime (years)	Cost w/o Gas Credit
$6,000	35%	350	3	$6.89/Mcf

Centrifugal Compressors (wet seals) – The seals in a centrifugal compressor perform a similar function to the rod packing in a reciprocating compressor – allowing the rotating shaft to move freely without allowing excessive high pressure gas to escape (Figure 3-6). Centrifugal compressors with wet seals use circulating oil as a seal against the escape of high pressure gas, and the oil entrains some of the gas as it circulates through the compressor seal. This gas must be separated from the oil to maintain proper operation (called "degassing the seal oil"), and the gas removed from the seal oil is typically vented to the atmosphere.[22] These emissions can total 30,000 Mcf/year or more. While wet seals can be replaced by dry seals that do not use oil and do not vent significant amounts of gas, this is an extremely expensive process. A lower cost option is to capture and use the entrained seal oil gas rather than venting it. This technology currently exists at several compressor stations that had such systems installed as original equipment, but it has not been applied commercially as a retrofit. However, the equipment needed for a retrofit is commercially available. The measure modeled here is to apply this technology as a retrofit. This is described as one of the case studies in section 5.1 where the capital cost is estimated at $33,700 for a 99% reduction. Because this technology has not been commercially demonstrated as a retrofit, the analysis assumed a conservative cost of $50,000 and 95% reduction, yielding a cost-effectiveness of -$4.87/Mcf with credit for recovered gas or $0.21/Mcf without recovery. Although the gas can be re-captured, it may be difficult to use it productively, as this depends on both the pressure of the captured

[22] Replacing Wet Seals with Dry Seals in Centrifugal Compressors http://www.epa.gov/gasstar/documents/ll_wetseals.pdf

gas and whether a need for the gas exists. The applicability is therefore discounted by 10% to 25% depending on the industry segment.

Figure 3-6 - Wet Seal Compressor Schematic



Pneumatic Devices – Pneumatic devices use the pressure of the natural gas stream to operate various control functions, such as adjusting valves to maintain proper pressure, actuating liquid level and temperature controllers, etc. Some devices require a continuous small discharge of gas as part of the controller function. These types of devices are designated as either low bleed devices (emitting < 6 scf/hr) or high bleed devices (emitting ≥6 scf/hr, but typically much more – often more than 30 scf/hr). In addition to these two categories, there are intermittent bleed devices that are designed to discharge gas only when they are actuating. These types of pneumatic devices can have emissions anywhere between high and low bleed controllers. One common device is an intermittent level control device ("dump valve") that emits gas only when actuated and typically has emissions similar to low bleed controllers.

The EPA GHG Reporting Program Subpart W provides information on pneumatic controllers that can be used to estimate the distribution of these devices in each segment. This analysis is discussed in Appendix B and, for example, yields a distribution of 10% high bleed, 50% intermittent bleed, and 40% low bleed devices for the Production segment. Further analysis was performed to estimate the distribution of higher-emitting intermittent devices vs lower-emitting dump valves, also discussed in Appendix B. For the Production segment, it was estimated that 75% of the intermittent bleed devices are lower-emitting dump valves.

The two mitigation options considered in the study are:

- Replace high bleed controllers with low bleed controllers.

- Replace high-emitting intermittent controllers (not dump valves) with low bleed controllers.

Some components require high bleed controllers for operational reasons, primarily for fast-acting valves associated with compressors, so the measure was applied to only 60% of the inventory of high bleed controllers in transmission, storage, and LNG, 80% in processing and 90% of the high bleed controllers in other segments. Although there are lower cost estimates from Gas STAR and vendors, this measure assumed a cost of $3,000 per replacement based on industry comments. Both options yield a greater than 90% reduction. This yields a reduction cost of -$3.08/Mcf of methane for replacement of high bleed pneumatics and $0.58/Mcf of methane for replacement of intermittent bleed pneumatics, including a credit for recovered gas, where applicable.

Chemical Injection Pumps – These are small pumps used to inject various chemicals, most commonly methanol, into gas wells to prevent well freeze-up during cold weather. They are typically driven by gas pressure and vent gas when they operate. The suggested mitigation measure is to replace the gas-driven pumps with electric pumps driven by solar energy. (Well pads and many gathering/boosting stations typically do not have electricity.) This technology has been demonstrated by Gas STAR Partners and industry respondents indicated that it is gaining broader acceptance. Replacement results in elimination of the methane emissions, and the gas-driven pump could be left in place as a back-up. The cost of the measure was estimated at $5,000 per pump, yielding an annual reduction of 180 Mcf/year and a cost-effectiveness of -$0.22/Mcf of methane reduced with the recovered gas credit. Local conditions or operational considerations may limit the applicability so the measure is applied to 80% of the inventory.

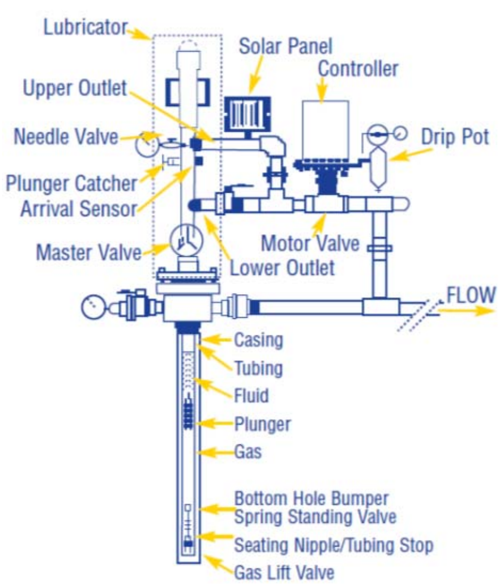
Oil and Condensate Tanks without Control Devices – Crude oil and liquid condensate production at wells and gathering facilities is stored in fixed roof field tanks and dissolved gas in the liquids is released and collects in the tank space above the liquid. Ultimately, this gas is often vented to the atmosphere. Vapor recovery units (VRUs) collect and compress this gas, which can then be re-directed to a sales line, used on-site for fuel, or flared. Based on Gas STAR and industry data, the capital cost of this measure is assumed to be $100,000 with an operating cost (electricity) of $7,500 per year and a reduction of 13,410 Mcf per year. This yields a reduction cost of -$0.51/Mcf if the gas is recovered for sale or $4.57/Mcf if it is flared. Some facilities already have VRUs and they may not be effective where the liquid volume is small or the methane content is low. Also VRUs require electricity, which is not available at all sites. For these reasons, the measure is applied to 50% of the remaining oil and 25% of the remaining condensate tank emission inventory.

Kimray Pumps – Kimray pumps are gas-powered pumps used to circulate glycol in gas dehydrators. They are larger than the chemical injection pumps and vent larger amounts of gas. In the facilities that have electricity, these could be replaced by electric motor-driven pumps. The replacement cost is estimated at $10,000 per pump based on vendor and Gas STAR data. Unlike the solar pumps, these pumps will require grid electricity, estimated to cost $2,000 per year. Based on a 5,000 Mcf emission reduction, the cost-effectiveness is -$4.17/Mcf of methane with credit for gas recovered and it is applied to 50% of the inventory.

Liquids Unloading – Liquids unloading is the process of removing liquids from the bottom of gas wells when the accumulation is impeding the gas production. The liquids must be removed in order to allow effective production from the well. Historically this has been practiced on older, vertical wells whose pressure has declined.

While there are a variety of methods of removing this liquid, one method is by venting or "blowing" the well to the atmosphere, using the pressurized gas in the reservoir to lift and blow the liquids out of the well. The frequency and duration of liquids unloading depends on the well and reservoir conditions, however, venting is not a very effective method of removing the liquids. Further, since the well is vented to the atmosphere, it results in large methane emissions and losses of gas. There are multiple methods of removing liquids without venting, but in standard practice, the primary goal of liquids unloading is to improve well performance, not reduce emissions. The choice of method is normally a function of the cost versus the value of improved well performance. This topic is further discussed in section 5.4.

Figure 3-7 - Plunger Lift Schematic



Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of venting (Figure 3-7). If there is sufficient reservoir pressure, the gas can be directed to the sales line with no venting. If there is insufficient pressure to direct the gas to the sales line and the gas must be vented, the emissions can still be reduced by 90% compared to uncontrolled venting. Plunger lifts are a relatively low cost option and can be implemented in a relatively simple manual control method or more complex automated installations. That said, the technology does have limitations. The well must have sufficient pressure to operate the plunger and older wells may require clean-outs or work-overs to allow the plunger to operate. Further, not all well types can use a plunger lift for liquids removal.

Gas STAR estimates for plunger lift installation range from $2,500 to $10,000[23] but industry commenters on this study cited costs in the range of $15,000 and pointed out that well treatments and clean-outs may be required before plunger lifts can be installed. This analysis assumes a cost of $20,000, including the allowance that some wells may need clean-outs or other work. Gas STAR Partners report reductions of venting emissions of 90% for plunger lifts that do not go to the sales line. In addition, they report that liquids unloading can increase production by anywhere from 3 to 300 thousand cubic feet per day

[23] Installing Plunger Lift Systems In Gas Wells http://epa.gov/gasstar/documents/ll_plungerlift.pdf

(Mcf/day). The increased productivity of the well is the primary goal of liquids unloading and the higher gas production can pay for the cost of plunger lifts many times over. However, the subsequent increase in well productivity is difficult to predict and is not included in this analysis. Without credit for the productivity increase, the cost-effectiveness breakeven point is at about 1,200 Mcf/year of venting, estimated here as a reduction cost of -$0.05/Mcf reduced.

If the well does not have sufficient pressure or cannot support a plunger lift, there are a variety of mechanical pumping technologies that can be employed to remove liquids. However, these are much more expensive and while they may have a positive payback for increasing well production, they most often do not purely for the methane emission reduction. Moreover, the methane reduction value only applies if the well would otherwise be vented. As the well pressure declines, venting becomes a diminishingly effective option. In addition, it is not clear how effective venting will be at removing liquids from long horizontal wells that are now being drilled. It may be that venting for liquids removal will continue to be primarily focused on older, vertical wells.

The GHG Reporting Program Subpart W provides data on wells that are venting for liquids unloading with and without plunger lifts. The data for 2012 show over 53,000 wells venting an average of 167 Mcf per year without plunger lifts and over 74,000 wells with plunger lifts venting an average of 277 Mcf per year. Wells that use plunger lifts and send the gas to the sales line do not have any venting emissions and do not report to this part of Subpart W. While it seems counterintuitive that wells with plunger lifts that vent would be emitting more than those without plunger lifts, ICF interprets this information to indicate that most of the wells with the largest venting emissions have already installed plunger lifts while most of the remaining wells are venting infrequently or venting small volumes that do not justify the cost of installing plunger lifts. That said, there are a small number of wells without plunger lifts that report larger venting emissions and account for a disproportionate fraction of the venting emissions for wells without plunger lifts, approximately 36% of total venting emissions. Installing plunger lifts on these wells could be cost-effective and create significant emission reductions. Because plunger lifts are not applicable to all wells, the measure was applied to 30% of this emission segment for the analysis.

As noted above, wells with plunger lifts also report significant emissions from venting. Operation of a plunger lift is complex and its effectiveness as an emission reduction technique depends on many factors to operate the plunger at the optimum time to maximize production and minimize emissions. Approaches to plunger lift operation range from ad hoc manual operation, to fixed mechanical timers, to programmable “fuzzy logic” automated controllers. Specific data on the potential reductions from optimized plunger lift operation is not available but it is clear from industry experience that an integrated program of training, technology, and automation can improve the performance of plunger lifts for both productivity and emission reductions. Consequently, there may be an opportunity for significant emission reduction through optimization of plunger lifts, which is not included here and would be additional to the reduction estimates this analysis provides for installation of new plunger lifts.

Stranded Gas Venting from Oil Wells and Venting of Oil Completion Gas – Oil contains some amount of natural gas, which is separated at the wellhead. Where there is a gas sales line available, the gas is sent to sales. When no nearby sales line exists, the gas is either vented or flared. This can occur during the short period after the well is completed or it can continue throughout the life of the well, depending on the access to gathering infrastructure. While flaring creates CO_2 emissions from combustion and some unburned methane, the total greenhouse gas emissions are much lower than venting the methane, with its higher global warming potential.

The measure modeled here is flaring of the gas on the assumption that the gas would be sent to sales if the infrastructure were available. While Gas STAR and vendor information cite relatively low-cost flares, industry cited more expensive flaring equipment that is being required to meet regulatory requirements. ICF adopted this higher estimate, assuming a capital cost of $50,000 and a fuel cost of $6,000 for ignition. The flare is assumed to be 98% effective. The cost-effectiveness depends on the amount of gas flared, which is lower for completion emissions than flaring of associated gas on a continuous basis. The cost-effectiveness is estimated at $1.86/Mcf of methane for completion gas and $0.26/Mcf of methane for flaring of stranded associated gas.

Pipeline Venting (Routine Maintenance/Upsets) – These emissions occur when companies take sections of pipeline out of service for maintenance and vent the gas that is in the pipeline. These emissions can be reduced for planned shutdowns (not emergency shutdowns) either by using the pipeline compressors to pump down the gas in the affected section or by using leased mobile compressor units when the pipeline compressors are not appropriately located. The analysis assumed a combination of both measures applied to 10 mile sections of pipeline, based on a Gas STAR analysis[24]. Using the pipeline compressor requires no capital cost but only the fuel cost to pump down the line. The second option was to lease a portable compressor and pay for the delivery and fuel consumption. The reductions are generally greater using a portable compressor, as these compressors can generally bring the pipeline down to a lower pressure than the inline compressors alone. Assuming that a leased compressor is used for one out of five occurrences, the cost was $0.41/Mcf of methane reduced, with no fuel recovery credit.

Transmission Station Venting – The major reason for transmission station venting is the government-required annual testing of relief valves to assure emergency shutdown (ESD) functions properly. During the standard practice in testing these systems, gas is vented from all of the relief valves at the station for a few minutes. These emissions can be avoided by putting quick opening closures over the relief valve to contain the gas when the relief valve is cycled open and closed, but allow a fast response if there is an emergency during the test. While Gas STAR has estimated the cost of this measure at $8,000, industry

[24] "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance". http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

respondents suggested a cost of $30,000 for a full station redesign. The cost adopted for the analysis was $15,000 assuming a change in procedure but no station redesign, yielding a cost-effectiveness of $0.98/Mcf with no gas recovery credit.

Summary

Table 3-6 summarizes the mitigation measures applied in the analysis for each major emission source. Table 3-7 summarizes the characteristics of the measures modeled. The cost-effectiveness ($/Mcf of methane removed) was calculated with and without credit for any recovered gas. The annual cost was calculated as the annual amortized capital cost over the equipment life plus annual operating costs. This was divided by annual methane reductions to calculate the cost-effectiveness without credit for recovered gas. Where gas can be recovered and monetized by the operating company, the value of that gas was subtracted from the annual cost to calculate the cost-effectiveness with credit for recovered gas. The costs shown here are the baseline costs, which are adjusted for regional cost variation in the analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

Table 3-6 - Summary of Mitigation Measures Applied

Source	Mitigation Measure
Oil/Condensate Tanks w/o Control Devices	Vapor Recovery Units
Liquids Unloading - Wells w/o Plunger Lifts	Plunger lifts
High Bleed Pneumatic Devices	Replace with low bleed devices
Intermittent Bleed Pneumatic Devices	Replace with low bleed devices
Chemical Injection Pumps	Solar electric pumps
Kimray Pumps	Electric pumps
Pipeline Venting (Routine Maintenance/Upsets)	Pipeline pump-down
Centrifugal Compressors (wet seals)	Wet seal gas capture
Transmission Station Venting	Gas capture
Oil Well Completions - with Fracturing	Flaring
Stranded Gas Venting from Oil Wells	Flaring
Reciprocating Compressor Rod Packing	Rod packing replacement
Reciprocating Compressor Fugitives	Leak detection and repair (LDAR)
Compressor Station Fugitives	Leak detection and repair (LDAR)
Well Fugitives	Leak detection and repair (LDAR)
Gathering Station Fugitives	Leak detection and repair (LDAR)
Large LDC Facility Fugitives	Leak detection and repair (LDAR)

Table 3-7 - Summary of Mitigation Measure Characteristics

Name	Capital Cost	Operating Cost	Percent Reduction	$/Mcf w/ Credit	$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	$3,000	$0	97%	-$3.08	$1.99
Early replacement of intermittent-bleed devices with low-bleed devices	$3,000	$0	91%	$0.58	$5.65
Replacement of Reciprocating Compressor Rod Packing Systems	$6,000	$0	35%	$1.82	$6.89
Install Flares-Completion	$50,000	$6,000	98%	N/A	$1.86
Install Flares-Venting	$50,000	$6,000	98%	N/A	$0.26
Liquid Unloading - Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%	-$0.05	$5.03
Install Vapor Recovery Units on Tanks	$100,000	$7,500	95%	-$0.51	$4.57
Transmission Station Venting -Redesign Blowdown Systems /ESD Practices	$15,000	$0	95%	-$4.10	$0.98
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%	-$0.22	$4.86
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%	-$4.17	$0.91
Pipeline Venting - Pump-Down Before Maintenance	$0	$12,000	80%	-$4.67	$0.41
Wet Seal Degassing Recovery System for Centrifugal Compressors	$50,000	$0	95%	-$4.87	$0.21
LDAR Wells	$169,923	$146,250	60%	$2.52	$7.60
LDAR Gathering	$169,923	$146,250	60%	$0.91	$5.98
LDAR Large LDC Facilities	$169,923	$146,250	60%	$10.03	$14.45
LDAR Processing	$169,923	$146,250	60%	-$0.98	$4.10
LDAR Transmission	$169,923	$146,250	60%	-$2.28	$2.15

3.6. Source Categories Not Addressed

Several source categories with relatively large emissions were not addressed in the analysis. The sources and the reasons for their treatment are summarized below.

- **Off-shore oil and gas production** – As noted earlier, the EPA inventory provides very limited data on offshore emissions, which were not adequate to apply the methodology used for other sources. This is an area in which further analysis would probably yield additional opportunities for reduction.
- **Cast-iron gas mains** – Cast-iron mains have been identified is a significant emission source, however they are primarily located in congested urban areas where replacement or repair is very expensive, reported as $1 million to $3 million per mile. This makes for a very expensive control option based purely on emission reduction. Moreover, these expenditures must be approved by state utility commissions, whose purview typically does not extend to environmental remediation of this type. That said, approximately 3% of cast iron mains are being replaced each year for safety reasons, so the emissions are gradually declining. New technologies could reduce the cost of reduction in the future.
- **Engine exhaust** – The exhaust from gas-burning engines and turbines contains a small amount of unburned methane from incomplete combustion of the fuel. While it is a small percentage, it is significant in aggregate. Oxidation catalyst devices are used to reduce unburned emissions of other hydrocarbons in the exhaust but they are not effective at reducing emissions of methane due to its lower reactivity. However, new catalysts are being developed, in part for natural gas vehicles, which may be applicable to these sources. This is a topic for further research and technology deployment.
- **Other sources** – There are additional cost-effective measures for methane reduction that have been identified by the EPA Gas STAR program and others. They are not included here because this report focuses only on the largest emitting sources. However, their omission should not be taken to indicate that the measures listed here are the only cost-effective methane reduction measures.

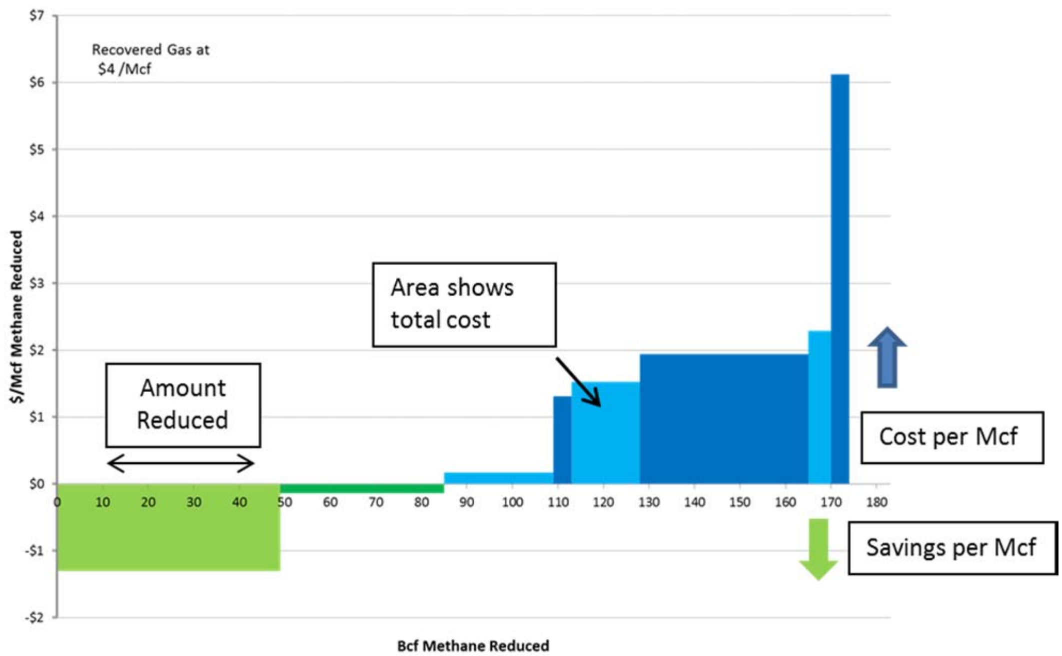
4. Analytical Results

4.1. Development of Emission Control Cost Curves

With the 2018 Projected Baseline established and mitigation technologies identified and characterized for the major emitting sectors, emission cost reduction curves were calculated for a variety of scenarios. The model developed for this task includes the individual source categories for each segment of the oil and gas industry by region. Mitigation technologies can be matched to each source by region and/or individual source applied. The model can also specify what portion of each source population the measure applies to and whether it applies to new (post-2011), existing (as of 2011), or all facilities. The model calculates the reduction achieved for each source and calculates the cost of control based on the capital and operating costs, the equipment life, and where appropriate, the value of recovered gas. Key global input assumptions include: whether a particular segment is able to monetize the value of recovered gas, the value of gas, and the discount rate/cost of capital. A construction cost index is used to account for regional cost differences, which are 13% to 24% higher for continental U.S. locations other than the baseline Gulf Coast costs.

The results are presented primarily as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 4-1. This representation shows the emission reductions sorted from lowest to highest cost-of-reduction and shows the amount of emission reduction available at each cost level. The vertical axis shows the cost per unit in $/Mcf of methane reduced. A negative cost-of-reduction indicates that the measure has a positive financial return, i.e. saves money for the operator. The horizontal width of the bars shows the amount of reduction. The area within the bars is the total cost per year. The area below the horizontal axis represents savings and the area above the axis represents cost. The net sum of the two is the total net cost per year.

Figure 4-1 - Example MAC Curve



4.2. Emission Reduction Cost Curves

This section presents the results of the cost curve analysis. The curves represent different views of a potential emission control scenario in 2018 based on measures installed between 2011 and 2018. The emission reduction costs are the annual costs per Mcf of methane reduced. This should not be confused with cost per Mcf of natural gas produced, which is an entirely different metric. In the cases shown here, the total annual cost of reductions divided by total U.S. gas production is less than $0.01/Mcf of gas produced in all cases.

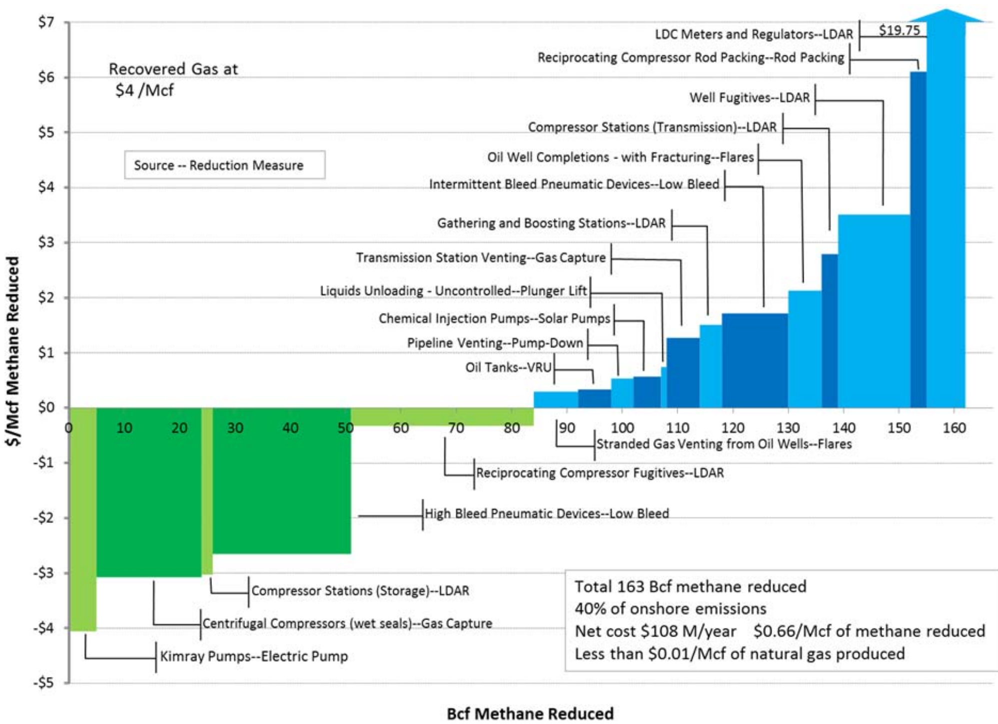
There are several caveats to the results:

- The 2011 EPA inventory is the best starting point for analysis, but it is based on many assumptions and some older data sources. Although the inventory is improving with new data, it is designed to be a planning and reporting document and is imperfect, especially at the detailed level, for a granular analysis of this type.
- Emission mitigation cost and performance are highly site specific and variable. The values used here are estimated average values.
- The analysis presents a reasonable estimate of potential cost and magnitude of reductions within a range of uncertainty.

The base case assumption for the results in this section assumes a $4/Mcf price for recovered gas and a 10% discount rate/cost of capital for calculating the cost of control. Additional sensitivity and alternative cases are shown in Appendix A.

Figure 4-2 shows the national aggregate MAC curve for the baseline technology assumptions by source category. It shows the reductions achievable from each source with the relevant emission control measure. These results are aggregated across industry segments, so the "reciprocating compressor fugitives" block, for example, includes the cost and reductions from the source among all segments. The variations between regions and between segments for a given technology are averaged for each block.

Figure 4-2 – National Aggregate MAC Curve for Baseline Technology Assumptions



The total reductions are 163 Bcf of methane per year or 40% of the 2018 onshore emissions from the oil and gas industries. The total annualized cost to achieve those reductions is $108 million/year or $0.66/Mcf of methane reduced. This total annual cost is the net of the $164 million annual savings (green bars below the axis) and $272 million annual cost (blue bars above the axis). The chart shows which sources and technologies have the lowest cost-of-control (height - vertical axis) and the greatest reduction (width – horizontal axis). The results are also summarized in Table 4-1. The cost ranges from -$4.05/Mcf methane reduced for replacement of Kimray pumps with electric pumps to $19.75/Mcf methane reduced for LDAR at large LDC facilities. These costs include regional cost adjustments and are therefore different than the baseline costs listed in Section 3. Credit for recovered gas accrues to all sectors except transmission and LDCs, which are limited by rate regulation from monetizing the emission reductions. The reductions from VRUs on condensate tanks are included but are too small to appear on the curve.

Table 4-1 also shows the estimated initial capital cost. This is a top-down estimate based on the projected reductions and the capital cost per measure so the costs are less certain than in a bottom-up costing, particularly with respect to differences between segments. The total initial capital cost is estimated at $2.2 billion.

Table 4-1 – Annualized Cost and Reduction and Initial Capital Cost

Source/Measure	Annualized Cost ($ million/yr)	Bcf Methane Reduced/yr	$/ MCF Methane Reduced	Initial Capital Cost ($ million)
Kimray Pumps--Electric Pump	-$23.4	5.8	-$4.05	$23.1
Centrifugal Compressors (wet seals)--Gas Capture	-$58.7	19.1	-$3.07	$79.6
Compressor Stations (Storage)--LDAR	-$4.5	1.5	-$3.03	$2.8
High Bleed Pneumatic Devices--Low Bleed	-$67.4	25.4	-$2.65	$246.8
Reciprocating Compressor Fugitives--LDAR	-$10.5	32.3	-$0.33	$61.6
Condensate Tanks w/o Control Devices--VRU	$0.1	0.4	$0.21	$8.5
Stranded Gas Venting from Oil Wells--Flares	$2.4	8.2	$0.30	$228.3
Oil Tanks--VRU	$1.8	5.5	$0.33	$105.1
Pipeline Venting--Pump-Down	$2.3	4.2	$0.53	$0.0
Chemical Injection Pumps--Solar Pumps	$2.7	4.8	$0.57	$432.0
Liquids Unloading - Uncontrolled--Plunger Lift	$1.2	1.6	$0.74	$27.8
Transmission Station Venting--Gas Capture	$7.5	5.9	$1.27	$49.4
Gathering and Boosting Stations--LDAR	$5.0	3.3	$1.51	$17.7
Intermittent Bleed Pneumatic Devices--Low Bleed	$20.9	12.1	$1.72	$455.4
Oil Well Completions - with Fracturing--Flares	$14.5	6.8	$2.13	$50.4
Compressor Stations (Transmission)--LDAR	$7.7	2.8	$2.79	$5.3
Well Fugitives--LDAR	$43.9	12.5	$3.51	$84.4
Reciprocating Compressor Rod Packing--Rod Packing	$22.3	3.6	$6.11	$182.3
LDC Meters and Regulators--LDAR	$140.6	7.1	$19.75	$91.5
Grand Total	**$108.3**	**162.9**	**$0.66**	**$2,151.9**

Figure 4-3 shows the emission reductions by major category. Reducing fugitive emissions is the main opportunity for reduction, followed by reduced venting and replacement of pneumatic devices. While those categories include a wide range of sources, wet seal centrifugal compressors represents a single equipment type and mitigation measure.

Figure 4-3 - Distribution of Emission Reduction Potential

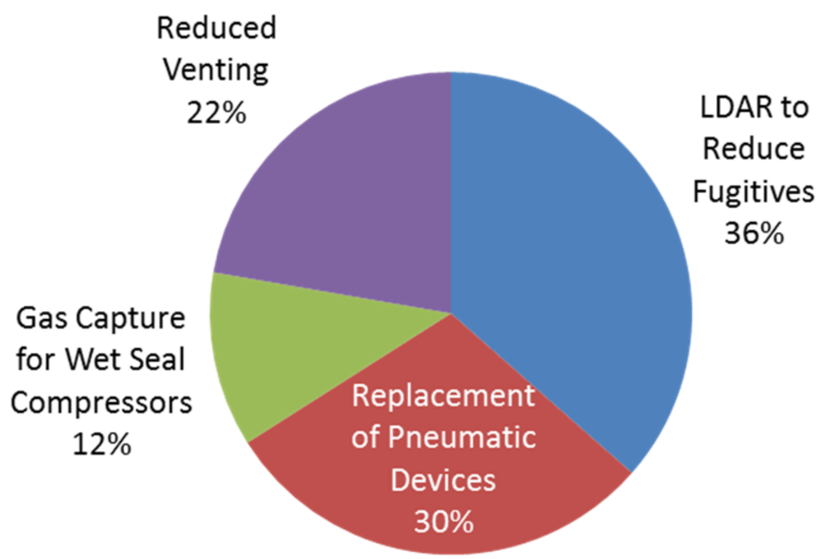


Figure 4-4 shows the reduction in methane emissions by industry segment for the same case. The transmission and distribution sectors are not able to monetize their reductions and therefore have a net positive cost. The LDC segment has only one measure and is the highest cost. The costs for the other sectors depend on the particular mitigation options available in each and their aggregate cost. The oil and gas production segments plus gas transmission account for almost 70% of the total reductions.

Figure 4-4 - Emission Reduction by Industry Segment

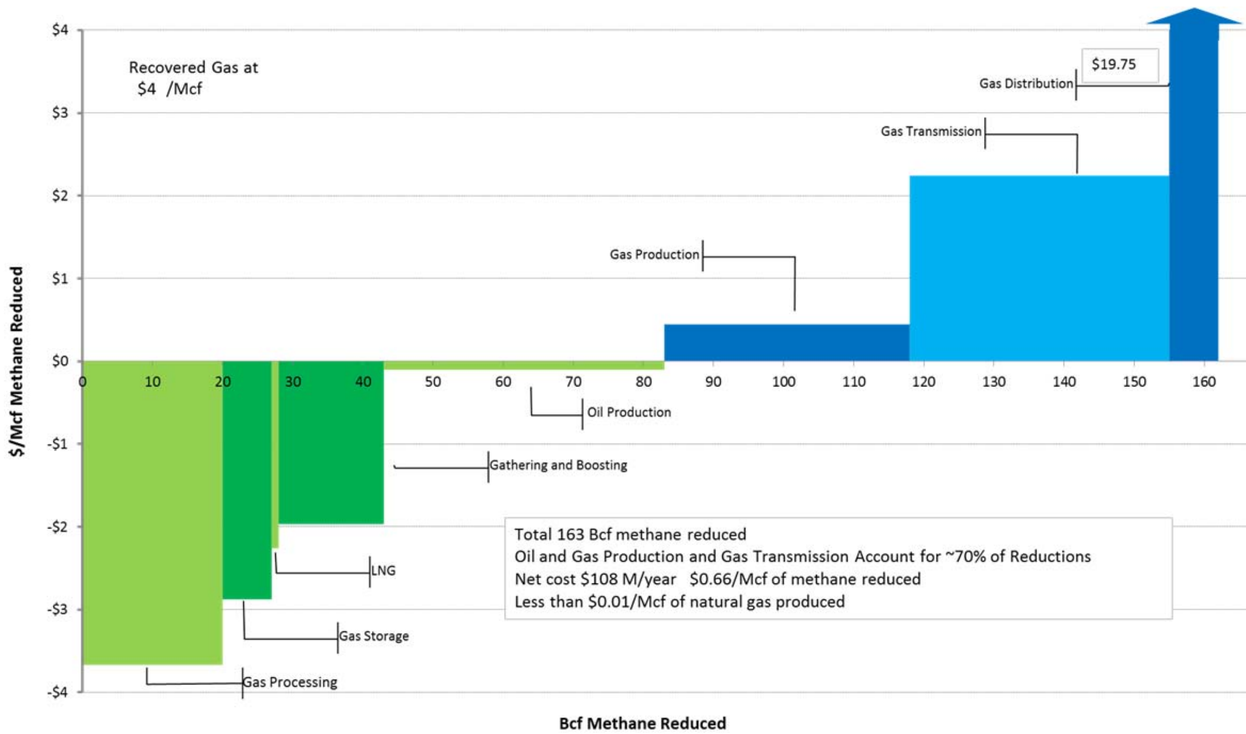


Table 4-2 shows the initial capital cost by industry segment. The majority of the costs, like the majority of the reductions, are in the oil and gas production segments, followed by transmission. Again, this aggregation by segment is approximate due to the top-down methodology used to develop the estimates.

Table 4-2 - Initial Capital Cost by Industry Segment

Segment	Initial Capital Cost ($ million)
Gas Processing	$85.3
Gas Storage	$42.1
Gathering and Boosting	$106.0
LNG	$12.4
Gas Production	$707.8
Oil Production	$865.6
Gas Transmission	$241.2
Gas Distribution	$91.5
Grand Total	**$2,151.9**

Figure 4-5 shows the breakdown of reduction options for the Gas Production segment. Replacement of high bleed and intermittent bleed pneumatic devices accounts for over half the reductions. LDAR for reduction of well fugitives is a positive cost and accounts for over a third of reductions. Replacement of high bleed pneumatics and Kimray pumps are the negative cost (savings) options. The total reduction is 35 Bcf with a net cost of $0.44/Mcf of methane reduced.

Figure 4-5 – Emission Reductions for the Gas Production Segment

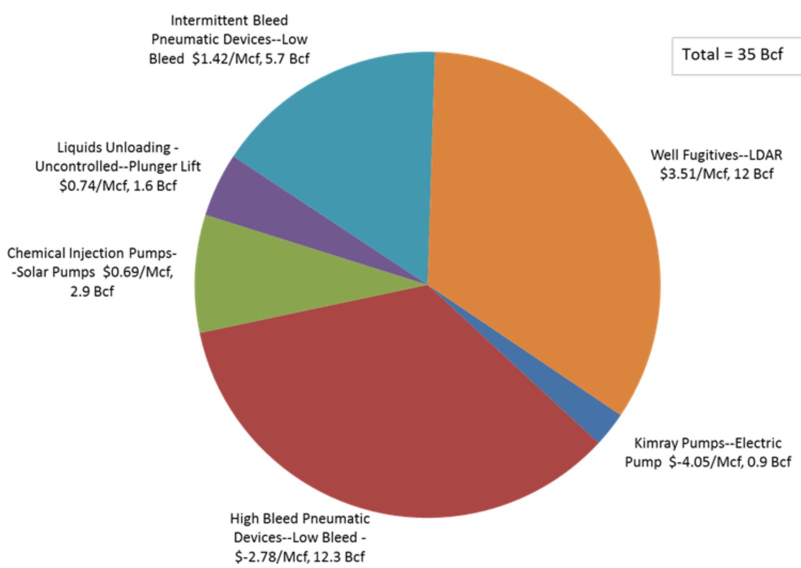


Figure 4-6 shows the reductions for the Oil Production segment. Replacement of high and intermittent bleed pneumatics are significant components, as in Gas Production, accounting for nearly half of the reductions. In addition, flaring of completion emissions and stranded associated gas are also significant but no gas is recovered from the flaring. Methane recovery from oil tanks is the other significant measure for this segment. The total reduction is 39.5 Bcf at a cost of -$0.10/Mcf of methane reduced.

Figure 4-6 - Emission Reductions for the Oil Production Segment

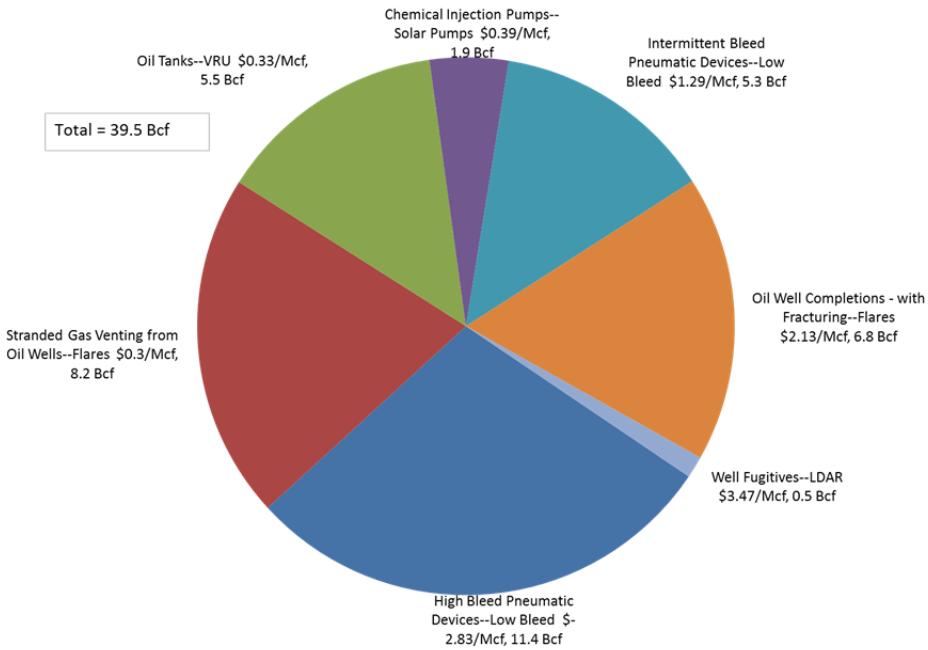


Figure 4-7 shows the reductions for Gathering and Boosting. LDAR to reduce fugitives at stations and reciprocating compressors accounts for over half the reductions while electrification of Kimray pumps accounts for over a third. The total reduction is 15 Bcf at a cost of -$1.97/Mcf of methane reduced.

Figure 4-7 - Emission Reductions for the Gathering and Boosting Segment

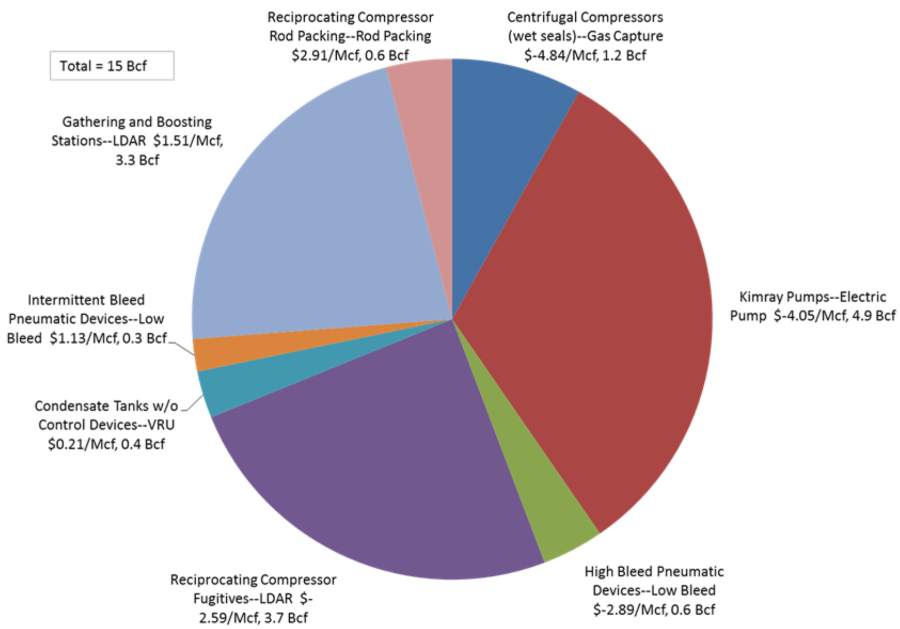
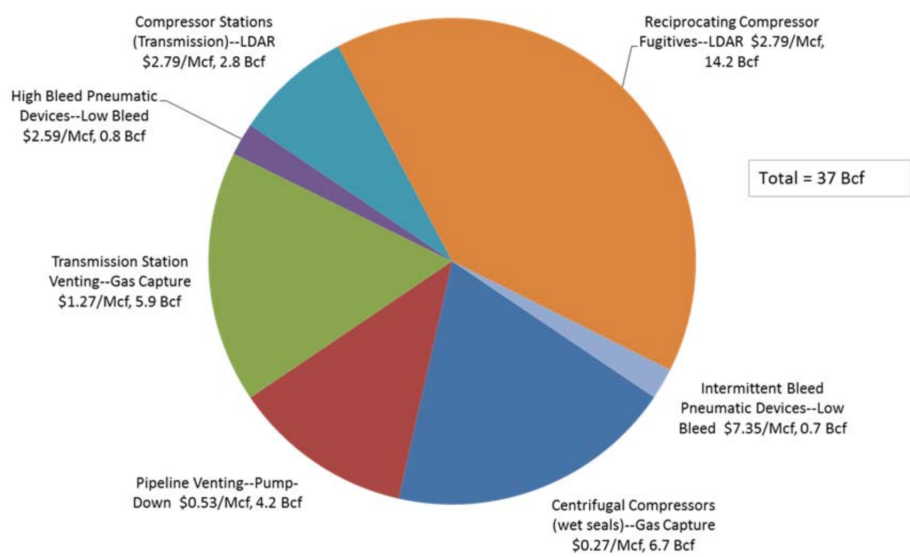


Figure 4-8 shows the reductions for the gas transmission segment. LDAR reductions of fugitives from stations and compressors are the largest components. Capture of degassing emissions from wet seal centrifugal compressors and reduced venting are the other significant measures. Due to regulatory limitations, transmission pipelines are not able to monetize emission reductions, so the cost of reductions is positive for all measures, $2.24/Mcf of methane reduced for 37 Bcf of reductions.

Figure 4-8 - Emissions Reductions for the Gas Transmission Segment



As discussed earlier, the baseline cost-effectiveness assumption is that the value of recovered gas is recognized in all of the upstream sectors but not in transmission or distribution, due to regulatory constraints. Figure 4-9 shows the sector-wide MAC curve for the base case when the value of the recovered gas is recognized for all sectors as an economy-wide value. The order of the measures is slightly re-ordered but more importantly, much of the cost curve is shifted downward as a result of including the full value of the gas recovered. The total net cost now is -$150 million/year or -$0.92/Mcf. In other words, if the economic value of all potentially recovered gas is accounted for, onshore emissions can be cut by over 40% at a net negative cost.

Figure 4-9 - National Aggregate MAC Curve with Baseline Technology Assumption and Economy-Wide Value Recognition

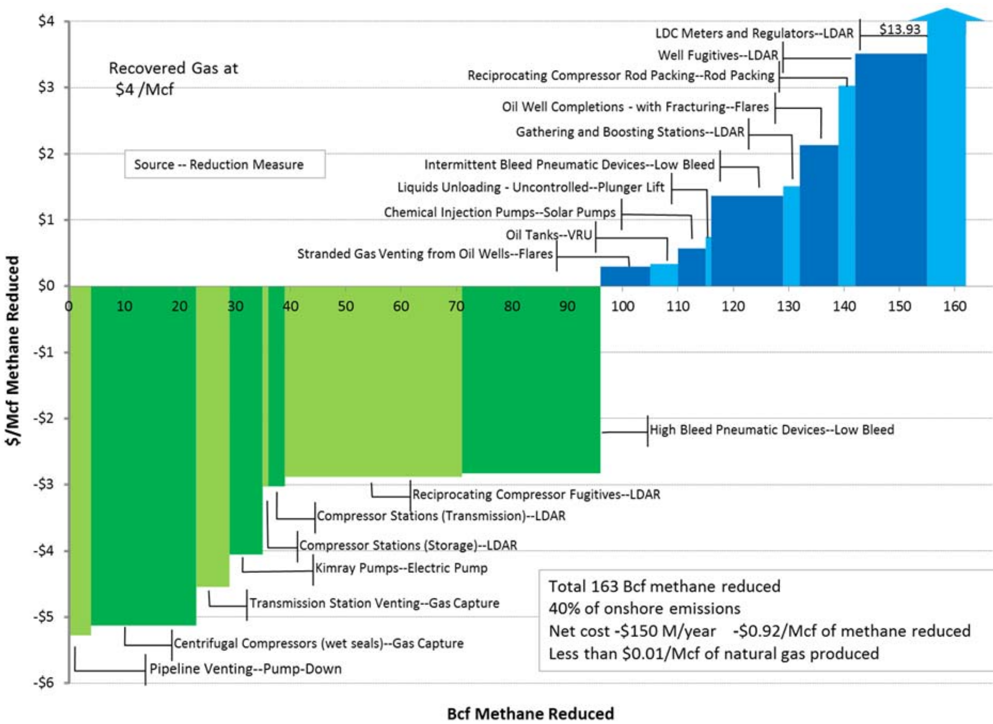
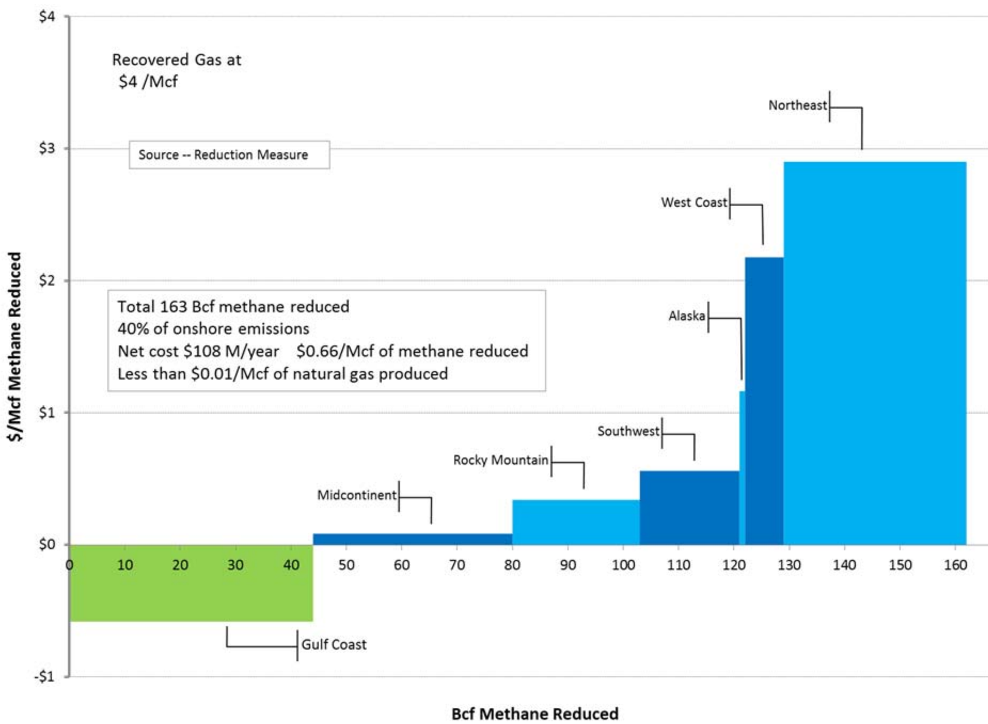


Figure 4-10 shows the MAC curve results by region. The magnitude of the reduction (width of the bar) is driven by the reduction potential in the region, which is related to the size of the region and the amount of oil and gas activity. It is also affected by the regional cost adjustments, which add 13% to 24% to the cost for regions outside the Gulf Coast. The Gulf Coast and Midcontinent account for almost half the reductions due the large amount of production in those regions. The Northeast also has a large share because it includes the eastern third of the U.S. and has an increasing amount of production. The cost (height of the bar) is determined by the mix of control measures within each region. The producing regions have more upstream measures with lower cost. The West Coast and Northeast have a lower share of production and a greater share of transmission and distribution sources that cannot monetize their reductions, and thus have higher average cost.

Figure 4-10 - National Aggregate MAC Curve by Region



4.3. Co-Benefits

Measures that reduce gas emissions will also reduce the emissions of conventional pollutants - volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) - in the gas as well as methane. Most of these components are removed from the gas at the gas processing stage so the primary co-benefits are at or prior to that stage in the value chain. Figure 4-11 shows that reductions are 44% of the original inventory of both pollutants. The net reduction costs are low relative to conventional control programs due to the economic value of recovered gas: $158/ton for VOCs and $4,147/ton for HAPs, however the cost-effectiveness for some individual sources with low emissions is much higher. Moreover, the same total annual cost ($108 million/year) is applied to the reduction for methane, VOC, and HAPs – that is allocating the full cost to each pollutant rather than dividing the cost among the pollutants, which would yield a lower cost of control.

Figure 4-11 – Co-Benefit Reductions of VOCs and HAPs

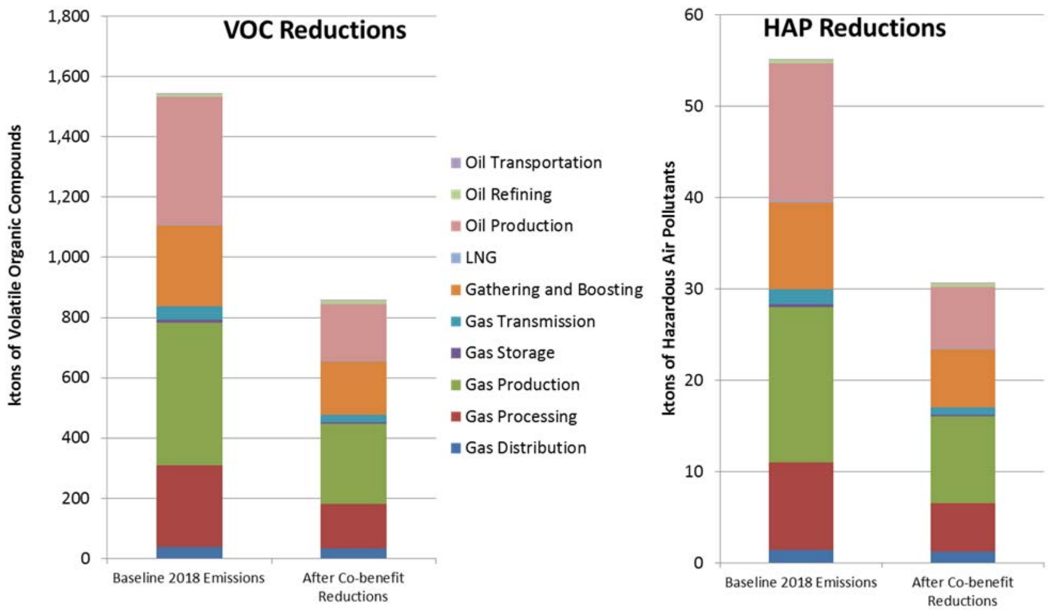


Figure 4-12 and Figure 4-13 show the sources of the co-benefits for reduction of VOCs and HAPs.

Figure 4-12 - VOC Reduction Co-Benefits

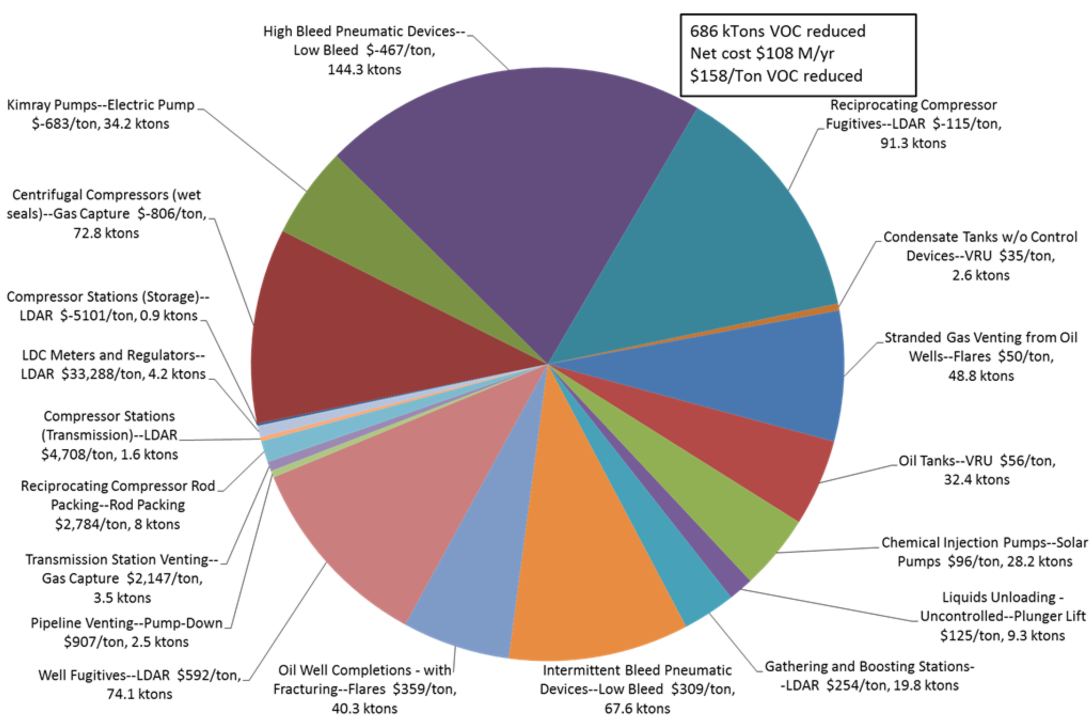
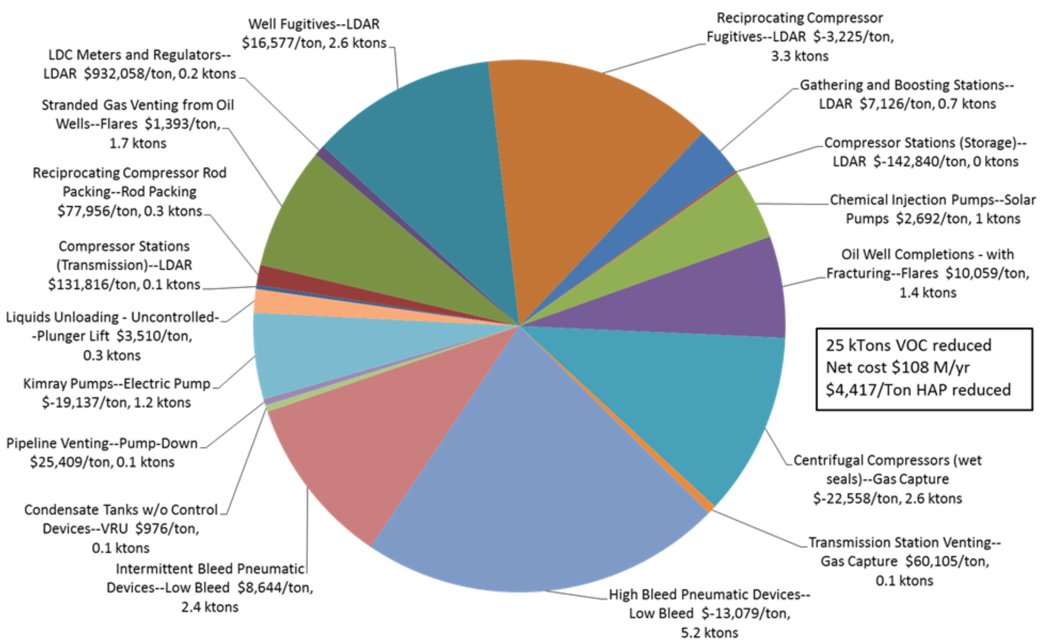


Figure 4-13 - Hazardous Air Pollutant Co-Benefits



5. Case Studies

This section provides additional background on two emissions sources that are of particular interest due to their large emissions and/or opportunity for reduction. The two sources are wet seal centrifugal compressors and liquids unloading from gas wells.

5.1. Wet Seal Compressor Degassing for Centrifugal Compressors

Centrifugal compressors are used widely throughout the petroleum and natural gas industry. These compressors can be used in a wide range of applications. Centrifugal compressors have a central rotating shaft with impellers that act to pressurize and compress the natural gas. These shafts are powered externally to the compressor casing, meaning that the shaft needs to pass through the casing. The opening where the shaft passes through the casing creates a path for the pressurized gas to escape. Different types of seals are used to prevent the gas from escaping.

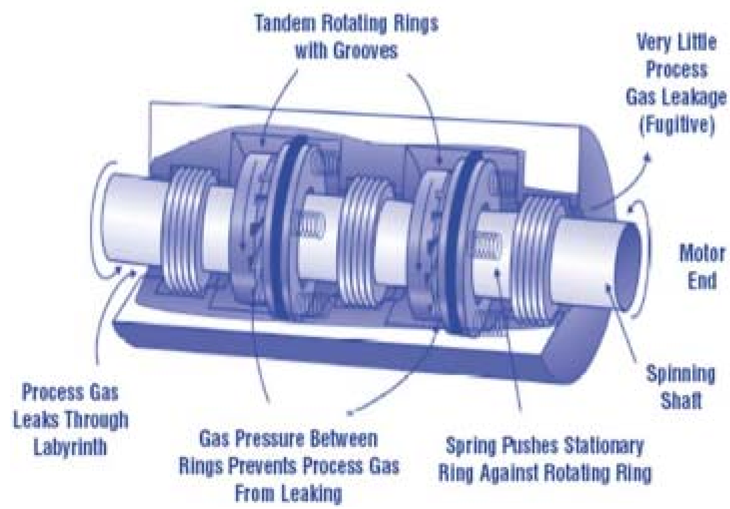
Wet Seals - Wet seals in centrifugal compressors use a lubricating oil kept at a higher pressure than the gas in the compressor casing, forming an effective barrier against gas leakage. Very little gas escapes through the barrier, but a considerable amount gets entrained in the oil that comes in direct contact with the high pressures gas at the “inboard” (compressor) side. In order to keep the seal oil in good condition, the seal oil must be purged of natural gas in a process called “degassing.”

During the degassing process, the contaminated seal oil is sent from the seal to a low pressure tank, called a “flash tank” kept near atmospheric pressure. When the oil/gas mixture enters the tank, the gas “flashes” out of the oil, effectively separating the gas from the oil. The now clean oil is then sent to a holding tank to be pressurized and recirculated through the seals. The gas that is removed from the oil is generally vented to the atmosphere, creating significant methane emissions.

Dry Seals - The mechanical “dry seal” does not use circulating seal oil but instead operates mechanically under the opposing force created by hydrodynamic grooves and static pressure as shown in Figure 5-1. Dry seals consist of two rings on the compressor shaft where the shaft exits the compressor casing. One of these is a stationary ring, and one is a rotating ring. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates, hydrodynamic grooves etched into the surface of the rotating ring direct gas between the rotating ring and the stationary ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a minute gap between the rings through which little gas can leak. Further, this gas between the rings means that the rings do not touch during operation, significantly reducing wear and eliminating the need for a lubricant.

Since dry seals do not require a lubricant, there are no emissions from degassing. In fact, the only emissions from the seal are the gas that leaks through the seal itself. According to studies, the leak rate across dry seals is approximately 3 scfm, substantially lower than the emissions from wet seals, which range from 40 to 200 scfm.[25, 26]

Figure 5-1 - Dry Seals on a Centrifugal Compressor



5.2. Dry Seal Replacement/Retrofit

One option to reduce methane emissions is to use a dry seal compressor instead of a wet seal compressor. This can be accomplished by either replacing the compressor or retrofitting it to use dry seals. Both of these options can be viable, depending on the project, but are almost always quite expensive, usually over $300,000 per compressor. Therefore, this option is often not cost-effective.

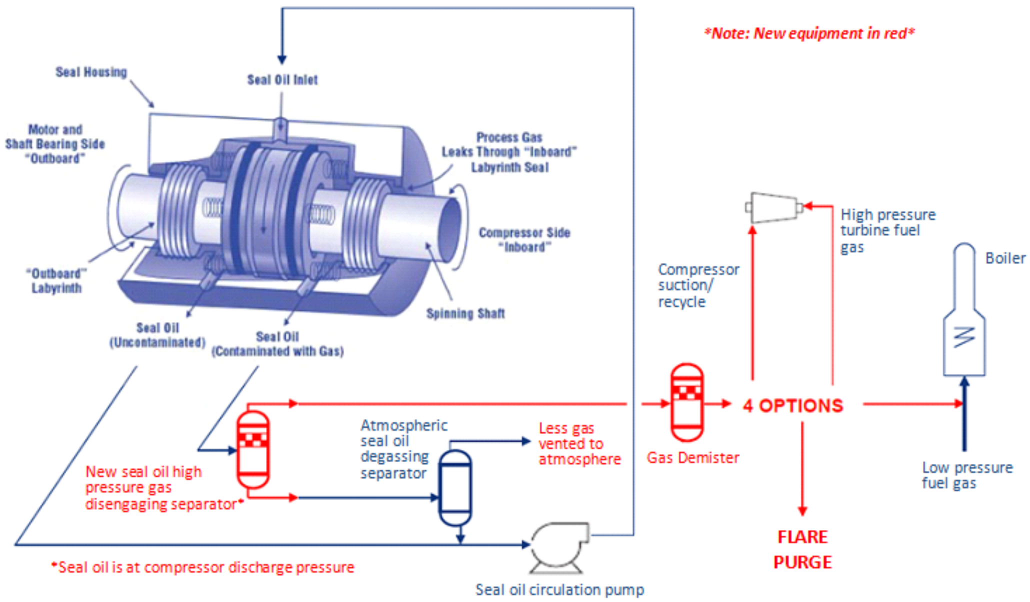
5.3. Wet Seal Degassing Capture Systems

Another, substantially less expensive option is to install equipment to capture and use or flare the gas that flashes out during the degassing of the seal oil. This system uses two separators, one at high pressure, and one at lower pressure. The high pressure separator operates at the seal oil pressure, and the gas flow is controlled by a critical orifice. This high pressure captured gas is then routed to a seal oil demister to remove any remaining seal oil before being routed to beneficial use. The oil then flows from the high pressure separator to the atmospheric degassing separator where the remaining entrained gas

[25] U.S. EPA. "Replacing Wet Seals with Dry Seals in Centrifugal Compressors." http://epa.gov/gasstar/documents/ll_wetseals.pdf
[26] Southcott, et. al. "Dry Gas Seal Retrofit." http://turbolab.tamu.edu/proc/turboproc/T24/T24221-230.pdf

is removed and vents to the atmosphere. This volume of gas is usually minimal, as most of the gas can be removed in the high pressure separator. The regenerated seal oil can then be recirculated back to the compressor seal oil system. This arrangement is shown Figure 5-2. These systems have been installed operated successfully as original equipment at several gas compression stations. Their use as a retrofit technology is a new application.

Figure 5-2 Wet seal degassing recovery system for centrifugal compressors (Source U.S. EPA)



Wet seal degassing recovery systems could potentially be installed at most locations with wet seal centrifugal compressors, though there may be limitations due to site-specific operating requirements. In order to implement this system there must be a use for the recovered gas. Operators have several options on how to best utilize this gas, and these choices will impact the economics of the project. The most common options are:

- Use as high pressure turbine fuel (~250 psig)
- Route the recovered gas as low pressure fuel (~50 psig)
- Route back to compressor suction
- Use as a flare sweep gas

Not all of these applications may be available at all sites. In addition, gas recovered from the low pressure side of the compressor may not be usable for high pressure applications or may require compression depending on the application.

5.3.1. Economic Analysis of Installing Wet Seal Degassing Capture Systems

The analysis of a wet seal degassing recovery system should consider the capital and operational costs along with the methane emissions savings. Two detailed economic analyses are shown below. The first scenario depicts installing the wet seal degassing recovery system on a single centrifugal compressor. The second illustrates a wet seal degassing recovery system installed at a compressor station with four centrifugal compressors.

The investment per compressor to use this technology includes the cost of a high pressure seal oil separator, new piping, pressure and flow controls, and the labor to design and install the equipment. In most cases, incremental operating and maintenance costs are expected to be minimal. If the gas is to be used as fuel, a demister will also be required in order to remove any entrained seal oil from the gas that exits the high pressure separator. If the recovered gas is routed to a higher pressure fuel system, an additional seal oil high efficiency filter/separator will likely be required to ensure all the oil mist is removed.

The estimated capital cost for each separator includes the purchase cost of the vessel, piping, instrumentation, structural support, electrical, painting, shipping, insurance, and installation. Table 5-1 summarizes these cost estimates (in 2013 U.S. dollars) for each piece of installed equipment in a degassing recovery system.

Table 5-1 - Degassing Recovery System Estimated Installation and Equipment Costs

Equipment	Capital Cost – One Centrifugal Compressor	Capital Cost – Compressor Station (Four Compressors)
Seal-Oil/Gas Separator*	$19,700	$78,800
Seal Oil Gas Demister – Low Quality Gas	$9,000	$9,000
Seal Oil Gas Demister – High Quality Gas	$5,000	$5,000
Total	$33,700	$92,800

*Assumed two seals per centrifugal compressor and four centrifugal compressors at the station. An individual high pressure seal oil gas separator costs about $9,850 per seal.

High Pressure Seal Oil Gas Disengagement Separators

For each centrifugal compressor, a seal oil gas separator is to be installed for each seal or pair of seals (assuming the pair is operating at the same seal oil pressure). The seal oil gas separators can be designed to operate at the same pressure as the seal oil exiting the seal housing. The total cost of each seal oil gas separator is estimated at $9,850, and with two separators per compressor (one for the seal at each end of the shaft), the total cost per compressor is $19,700.

Seal Oil Recovered Gas Demister/Filter

After being recovered, the gas must pass through at least one high-efficiency demister to remove entrained seal oil before it can be sent to a fuel line. If the oil isn't removed, the entrained oil may foul burners and potentially clog fuel injectors. This demister can be designed to receive gas from multiple separators, thereby lowering the overall cost. However, the design characteristics of this vessel will vary depending on the number separators connected to the vessel. The estimated cost for a single-stage is approximately $9,000. This cost will be used for both the single compressor and the compressor station examples.

If the recovered gas is to be sent to a high pressure fuel system, such as to power the compressor, the recovery system may need to include a second high-efficiency filter. This is used to ensure that trace amounts of seal oil do not foul these more sensitive fuel injectors. The estimated cost for the second seal oil high-efficiency filter is approximately $5,000.

Piping and Instrumentation

Piping modifications will be required in order to route the seal oil exiting the compressor seal to the new separator then to the degassing tank. Additional pipes and valves will be needed to transport the recovered gas to the demisters and further to the end use site. Controls will also need to be installed to regulate the pressure and flow of the recovered gas from each high pressure separator. This can be accomplished with a critical orifice on the gas outlet from each separator which restricts gas flow using choke flow effects. The piping and instrumentation costs are included in the installation and capital costs for each individual piece of equipment listed in Table 5-1.

Estimated Savings

The savings from this system are realized by generating additional gas sales if gas is routed to the compressor inlet, or by reduced costs if using recovered gas for site fuel. Based on measurement studies, the average methane emissions from centrifugal compressor wet seal degassing are 63 scfm of gas per compressor. Assuming 8,000 hours of operation per year, the total gas emissions per year would be 30 million cubic feet (MMcf) per compressor. Existing systems recover 99 percent of the entrained gas in the seal oil. Therefore, this analysis assumes that only 1 percent of the gas is vented. This means that nearly 30 MMcf of gas can be recovered per centrifugal compressor and will either displace the same volume in fuel gas or result in additional sales if routed to compressor suction. At $4 per thousand cubic feet (Mcf), savings from reduced fuel gas consumption is estimated to be $120,000 per year per centrifugal compressor, and a station with four centrifugal compressors could expect to avoid $480,000 per year in fuel gas costs.

Comparing Costs to Savings

The economics of implementing a wet seal degassing recovery system are shown in Table 5-2 using a five-year cash flow table. This analysis considers capital costs and savings from avoided fuel gas costs. The capital costs assume the operator installs both the demister for low pressure fuel gas and a high efficiency filter for high pressure fuel gas. While the actual economics will be highly site-specific, the analysis here shows that the economics of installing a wet seal gas recovery system are so attractive that companies should consider implementing this technology at any and all facilities with at least one centrifugal compressor with wet seals.

Table 5-2 - Wet Seal Degassing Recovery System Costs and Savings for One Compressor

Costs and Savings ($)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Capital & installation costs	($33,700)					
Annual natural gas savings ($4.00/Mcf)		$120,000	$120,000	$120,000	$120,000	$120,000
Net Present Value = $380,000 Internal Rate of Return = 350% Payback Period = 3 months						

Table 5-3 - Wet Seal Degassing Recovery System Costs and Savings for Four Compressors at a Station

Costs and Savings ($)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Capital & installation costs	($92,800)					
Annual natural gas savings ($4.00/Mcf)		$480,000	$480,000	$480,000	$480,000	$480,000
Net Present Value = $1,600,000 Internal Rate of Return = 520% Payback Period = 2 months						

With these assumptions, the wet seal gas recovery system would pay back in less than a year. The economics are compelling, but it should be noted that the installation may require each compressor to be briefly shutdown in order to tie the seal oil circulation piping into the new gas disengagement vessels. At new facilities requiring wet seal centrifugal compressors, installation can also integrate the degassing recovery systems into the process design. Wet seal degassing recovery systems are highly effective at capturing emissions from wet seal compressors and subsequently reducing fuel gas purchases and/or increasing gas sales with a high rate of return.

5.4. Liquids Unloading

5.4.1. Background

For many gas wells, particularly older gas wells, accumulation of fluids in the well is a serious issue. If left untreated, this accumulated fluid will slowly off the well to the point where it will no longer produce gas to the sales line. Because of this, the fluids that accumulate in these wells must be regularly removed or otherwise dealt with, a process known as "liquids unloading."

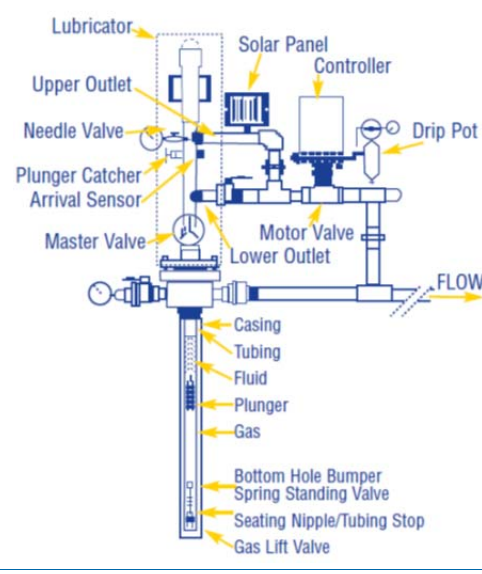
Operators of wells with liquids loading issues have several options to treat the well. The most basic remedy is to simply open and vent the well to the atmosphere. By opening the well to atmospheric pressure, which is substantially lower than the gas sales line pressure, the well will begin producing again. As the well is producing to the atmosphere, the gas will carry up and remove some of the accumulated liquids in the well tubing. After venting the well, which usually lasts at least several hours, the well will again be able to produce gas to the sales line. However, studies have shown that simply venting wells to the atmosphere only removes about 15% of the accumulated fluids in the well. This results in the need to frequently vent the well, as well as diminished overall production from the well. Of course it also results in significant methane emissions and lost gas revenue.

There are a variety of other options available to operators to remove liquids without venting or with much reduced venting. These range from foaming agents that reduce the density and surface tension of the liquid to pumping or "artificial lift" technologies that remove the liquid from the well tubing. Several of the most common unloading technologies are discussed below.

5.4.2. Plunger Lifts

A plunger lift is a type of artificial lift that harnesses the natural energy of a gas well to push a plunger and the accumulated column of fluid in the well to the surface. The gas pressure buildup in the casing-tubing annulus is used to push the plunger up the well while the plunger acts as a piston between the gas and the liquid, maximizing the liquid removal and minimizing venting. Ideally, the plunger discharges to the sales line, in which case there is no venting of methane to the atmosphere. Over time, however, the well may not have enough pressure to operate the plunger against the sales line pressure, in which case it will vent to the atmosphere. However, this is still typically a 90% reduction compared to venting the well without a plunger lift.

Figure 5-3 - Plunger Lift Schematic



A plunger lift system consists of several parts beyond just the plunger (Figure 5-3). At the top of the well, the plunger resides in a lubricator during normal gas well operation. The lubricator ensures that the plunger will travel freely up and down the well. At the bottom of the well is a bumper spring and hold down component. The bumper spring acts to catch and support the falling plunger before liquids removal. The hold down component prevents the bumper spring from travelling up the well with the plunger during liquids removal. In addition to these mandatory components, many operators choose to install automation equipment that will monitor and automatic deploy the plunger lift when necessary.

Plunger lifts operate on a cycle, either determined manually by the operator or automatically by an associated computer program. The pressures in the tubing and casing are monitored, and changes in these values are used to determine when to begin the plunger lift cycle.

At the beginning of the cycle, the well is shut-in to stop the flow of gas. As the well is being shut-in, the plunger falls from the lubricator to the bottom of the well with the liquid on top of the plunger. Pressure in the casing then begins building up. When the casing pressure is high enough to lift the plunger and the liquids to the surface, the sales line valve will open, again permitting the flow of gas from the well. The pressurized gas in the casing will then push the plunger and fluid column to the surface. As the plunger arrives at the top of the well, it is caught and is held in place in the lubricator. At this point, the well will be producing at the maximum flow rate. As fluid accumulates in the well again, the casing and tubing pressures will change. When those values hit their predetermined mark to trigger a plunger cycle, the sales line valve will close and the cycle will begin again.

Initially, the wells were shut-in manually by an operator. This required the operator to drive out to the well site, shut-in the well, wait for the plunger to cycle, and then open the well back to the sales line. This method was then streamlined by controlling the plunger cycles with simple mechanical timers. These timers ensured that the wells were plunged on a certain schedule, and eliminated the need for an operator to drive out to the well. However, well conditions change over time. If the liquid level in the gas well is allowed to get too high, the pressure in the well may not be enough to plunge the well to the sales line. In this case, the plunger may get stuck part way up the well and the well will need to be plunged to the atmosphere, resulting in methane emissions. If the fluid is too low, the plunger may come up too quickly and damage the wellhead.

A more recent development is the use of computers to automate plunger lift cycles. These computers collect and analyze data to determine the optimal time to plunge the wells, ensuring that the well runs as efficiently as possible. Actively tracking the well conditions can help to ensure that the well can be plunged to the sales line instead of the atmosphere, which can lower the overall methane emissions from the well. However, this technology generally only makes sense on wells that plunge frequently. If a well is only cycling once or twice a year, the added cost of automation may not make economic sense for the well.

5.4.2.1. Plunger lift costs

A typical plunger lift installation includes the downhole assembly, the lubricator, and the plunger itself, as well as associated vales and connections. The installation costs can be higher if automation equipment is installed as well. Table 5-4 shows typical cost ranges reported to the Gas STAR program for installing plunger lifts with and without automation, though current costs estimates are typically $7,500 to $15,000 and companies contacted for this study cited even higher costs if well clean-outs or over treatments are required.

Table 5-4 - Reported Capital and Operating Cost Ranges for Installing Plunger Lift Systems

Mitigation Option	Capital Cost	Annual O&M	Comments
Plunger Lift System	$2,500 to $10,000 per well	$1,000 to $10,000 per well	Capital cost represents plunger lift equipment and setup cost. O&M cost represents plunger lift maintenance such as inspecting/replacing lubricator and plunger.
Plunger Lifts System with “Smart" Automation	> $10,000 per well	$100 to $1,000 per well	The “Smart” Automation System can be installed at a cost of less than $12,000 per well dependent on the number of wells, current automation and transmission systems in place, and the location. The system requires additional field personnel training and engineering time to realize its full benefits.

Plunger lifts are designed to improve the production efficiency of older, liquids-rich gas wells. However, they can also prevent the wells from being vented to the atmosphere, as would have been done previously to remove liquids. The use of plunger lifts can help to substantially reduce methane emissions from wells by preventing unnecessary venting of the wells. However, operators must ensure that plunger lift implementation is designed to minimize emissions as well as improve productivity.

For example, plunger lifts are generally used to plunge the liquids in the gas well to the sales line. This requires that the pressures and flowrates in the well be closely monitored to ensure that sufficient energy exists to bring the plunger up during its cycle. If the pressure is allowed to fall too low, the well will need to be opened to the atmosphere to increase the pressure gradient and allow the plunger to bring the liquids to the surface. Allowing this to occur will reduce the potential emission reductions. Further, since the well has been cleared of liquids, the gas will be producing at or nears its maximum rate. If the well remains open to the atmosphere after plunger, which is common, the increased gas flow rate may negate or possibly even exceed emissions from venting a non-plunger well to the atmosphere.

5.4.3. Additional Options for Removing or Remediating Liquids Problems

There are a variety of other options to address liquids unloading. The most common of these options include foam-lift systems, gas-powered lifts systems, positive displacement systems, and velocity tubing strings. These systems are generally not applicable to all wells, and often times have a very limited range or lifetime of applicability.

5.4.3.1. Foam-Lift Systems

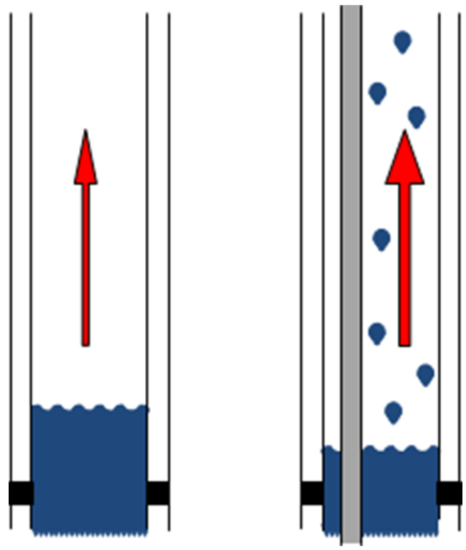
Foam-lift systems work by using a soap or surfactant (the "foaming agent") to alter the physical properties of the fluid. The surface tension and the liquid density of the liquids in the well are changed by the addition of the foaming agent, which then reduces the critical velocity needed lift the liquid from the well. The main restriction with the use of a foam-lift system is that the foaming agents only react with water, meaning these systems are limited to wells in which most of the liquid phase is water rather than a hydrocarbon liquid. The main use of foam-lift systems is in the deliquification of wells with low reservoir pressure that need to be continuously produced to high sales line pressures. The foam-lift systems can also find use when tubing restrictions prevent the use of plunger lifts in a well.[27]

5.4.3.2. Velocity Tubing

In a gas well, the velocity of the gas is the key factor in whether or not the gas can lift liquids out of the well. Once the gas velocity falls below the necessary velocity to lift the liquids, the liquids will begin to accumulate in the well, leading to lower production rates and ultimately shutting in the well. One option to increase the gas velocity is to lower the cross sectional area of the gas well tubing. This works because the velocity of a gas flowing through a section of pipe is inversely proportional to the cross sectional area of the pipe. This cross sectional area reduction can be achieved in a gas well one of two ways. Both of these ways involve inserting a smaller pipe, or "velocity tubing," inside the production tubing. The first option uses the velocity tubing to simply reduce the cross sectional area of the production tubing by not allowing gas to flow up the space occupied by the inserted tubing string. This method is shown in Figure 5-4. The second option is to use the inserted velocity tubing as the new production tubing. The method chosen will depend on how much the cross sectional area needs to be reduced in order to achieve the appropriate gas velocity.

[27] Weatherford. "Foam-Lift Analysis." http://www.clientdemos.net/weatherford_tus/lift_systems/foam-lift_systems

Figure 5-4 - Installation of Velocity Tubing Serving to Reduction the Cross Section Area of the Production Tubing



Note: A velocity tubing string is inserted into the well to decrease the annual area, thereby increasing the gas velocity, allowing for liquids removal from the well.

The installation of a velocity tubing string is a relatively simple process, beginning with calculating the proper tubing diameter needed to achieve the required gas velocity to lift the liquids out of the well. The actual installation of the velocity tubing string requires a well workover rig to install the smaller diameter tubing string in the well. Velocity tubing works best in low volume gas wells. Candidate wells include marginal gas wells producing less than 60 Mfcd.[28]

5.4.3.3. Gas-Powered Lift Systems

Gas lift systems are a type of artificial lift process that closely resembles the natural flow process of a gas well. These systems work by sending high pressure gas into the casing of the well in order to lower the hydrostatic pressure in the production tubing. With the hydrostatic pressure lowered, an increased pressure differential is established between the reservoir and the wellhead, allowing the gas to flow more freely and carry more liquid to the surface. The main requirement for gas lift systems is an economically available supply of high pressure natural gas. This high pressure gas can come from either nearby wells or a compression source. If a high pressure gas source is available, gas lift is typically the preferred form of artificial lift.[29]

[28] U.S. EPA. "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells." http://epa.gov/gasstar/documents/ll_options.pdf

[29] Weatherford. "Gas Lift Systems." http://www.weatherford.com/Products/Production/GasLift/

5.4.3.4. Positive Displacement Systems

Positive displacement systems are generally used when a well depletes to the extent that downhole pressures are insufficient to support any other type of artificial lift system. Positive displacement systems include progressing cavity pumps, electric submersible pumps, and reciprocating rod lifts, among others. All of these technologies work by utilizing some sort of outside energy source, such as a gas-powered engine or electric motor, to lift the fluid to the surface. These systems are generally much more expensive to install and operate than the other lift systems, but they are the only ones that can deplete liquid-producing gas wells to their lowest possible pressure.[30]

5.4.4. Liquids Issues in Horizontal Wells

The majority of oil and natural gas wells have been vertical wells. However, the past decade has seen a rapid growth of horizontal wells, particularly for shale gas production. These newer, horizontal wells have many benefits over traditional, vertical wells.

- Multiple wells can be drilled from a single well pad.
- Formerly inaccessible regions can be reached and produced.
- Increased productivity of wells by increasing contact with reservoir rock.

Most new production areas, including the Marcellus and Bakken formations, are being developed today thanks in part to this horizontal drilling technology. While most of these wells are still relatively new, eventually many of them are expected to face liquids loading problems as the well ages. This presents a unique challenge to the industry, as most technologies designed to remedy liquids loading issues are for vertical wells. This means that new technologies and techniques will need to be developed to overcome the unique issues presented by these new horizontal wells.

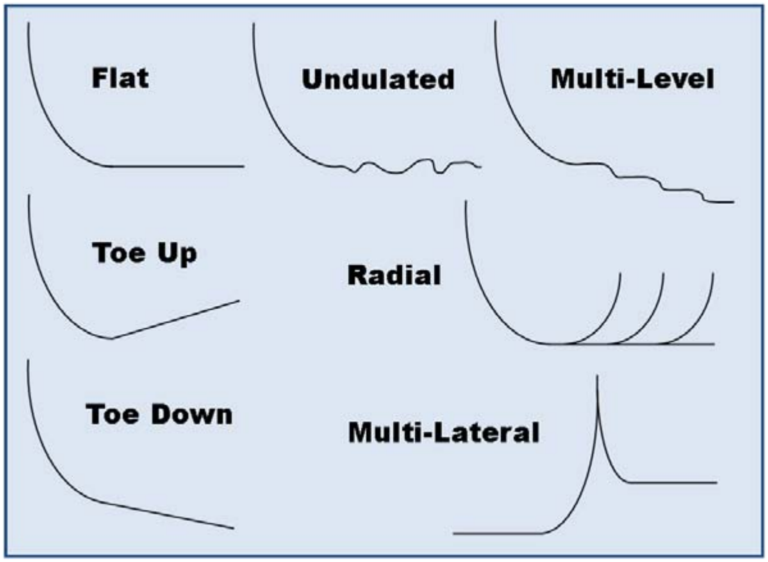
Most horizontal wells have very long non-vertical sections. These non-vertical sections are the main issue for these wells regarding liquids loading. Current technology, such as plunger lifts and foaming agents, are designed to work in vertical wells only. Both rely on gravity to place objects, either the plunger or the foaming agent, into the well. The non-vertical section of a well presents a challenge because gravity cannot assist in placing the object at the "bottom" of the well.

Further, many horizontal wells are not entirely horizontal. Figure 5-5 shows some of the different configurations that "horizontally" drilled wells can take. Further, many wells are often a combination of the well types shown in Figure 5-5. For example, a multi-lateral well may be drilled so that some legs

[30] Weatherford. "ESP and Positive-Displacement Lift Analysis." http://www.clientdemos.net/weatherford_tus/lift_systems/positive-displacement_systems

are positioned toe up, while others are positioned toe down, and the legs will contain undulations as well.

Figure 5-5 - Different Types of Horizontal Wells



Since wells are being directionally drilled, usually to contact as much of the reservoir rock as possible, undulations in the horizontal leg are extremely common. These undulations present serious challenges for overcoming potential liquids loading issues. Water and other liquids can accumulate in the low spots, while gas blocks can possible occur in higher spots.

Another issue faced by horizontal wells is the issue of determining critical gas flow velocity. Companies normally use this data in their determination on how to deal with liquids in a gas well. However, most models and equations that are currently used were developed for vertical wells. Overall, there is a need for improved understanding and models to determine the critical gas flow velocity in horizontal wells.

Currently, much work is being done to find adequate and economic solutions to liquids loading issues in horizontal gas wells. A consortium formed by the Artificial Lift R&D Council and lead by the University of Tulsa includes numerous artificial lift companies investigating different aspects of this issue. Their work includes the investigation of multiphase flow behavior in horizontal gas wells, the investigation of artificial unloading techniques in horizontal gas wells, and the development of guidelines and recommended practices for unloading horizontal gas wells.[31]

[31] Artificial Lift R&D Council. "Artificial Lift Selection for Horizontal Wells." http://www.alrdc.org/recommendations/horizontalartificiallift/index.htm

One of the major issues with removing liquids form horizontal wells is that the trajectory of the horizontal portion of the well impacts how liquids load and how they can be removed. However, the flow patterns of gas in these different trajectories are not currently well understood. This makes choosing the appropriate technology to recover the gas difficult, since each technology has certain limitations. Currently, the industry trend is to use the same or similar selection criteria that have already been identified for vertical or near-vertical wells. In order to ensure maximum efficiency is achieved from deliquefying horizontal wells, similar criteria must be developed for these wells.[32]

As an example, Muskegon Development, is using a technology called "Sequential Lift" in order to deliquefy horizontal gas wells. Muskegon, which produces in the Michigan Antrim shale, was experiencing liquids issues in the horizontal portion of their wells, creating high back pressures and severely reducing the production rates. Before switching to sequential lift systems, Muskegon had been using traditional gas lift in an attempt to remove liquids from their horizontal wells. However, the traditional gas lift systems were proving to be highly ineffective. In 2010, Muskegon began installing the sequential lift systems in their horizontal wells. This system places small pumps out to the end of the horizontal sections of well, resulting in much more complete well deliquification when used with gas lift systems. In fact, Muskegon stated that "the improved lift efficiency alone produced a reasonable payback, even without taking into account any improved productivity."[33]

Some companies have begun designing additional technologies to attempt to deal with liquids issues. For example, Lufkin has designed a hydraulic submersible pump specifically for horizontal wells. This pump's design can accommodate dewatering at low volumes, and the specific targeted formations are coal bed methane and shale gas plays. [34]

[32] Tulsa University. "TU Horizontal Well Artificial Lift Projects – Justification." Available online: http://tuhwalp.ens.utulsa.edu/technical_proposal/justification.html

[33] Fiberspar. "Enhancing Production and Improving Lift Efficiency in Low-Pressure Wells with Liquid-Loading Conditions." Available online: http://fiberspar.com/sites/default/files/cs01_mar11.pdf

[34] Lufkin. "HSP 5000™ Hydraulic Submersible Pump." http://www.lufkin.com/index.php/component/content/article/16-products-a-services/oilfield/100-hydraulic-submersible-pump

6. Conclusions

The key conclusions of the study include:

- **Emission Growth** - Methane emissions from oil and gas operations are projected to grow 4.5% from 2011 to 2018, including reductions from recent regulations (NSPS Subpart OOOO). All of the projected net growth is from the oil sector, largely from flaring and venting of associated gas. Nearly 90% of the emissions in 2018 come from existing sources (sources in existence in 2011).
- **80/20 Rule for Sources** - 22 of the over 100 emission source categories account for over 80% of the 2018 emissions, primarily at existing facilities.
- **Abatement Economics** - A 40% percent reduction in onshore methane emissions is projected to be achievable with existing technologies and techniques at a net total cost of $0.66/Mcf of methane reduced, or less than $0.01/Mcf of gas produced. The cost for some measures and segments of the industry is more or less than the net total. The initial capital cost of the measures is estimated to be approximately $2.2 billion with the majority of the costs in the oil and gas production segments.
- **Abatement Opportunities** – By volume, the largest opportunities target leak detection and repair of fugitive emissions (“leaks”) at facilities and gas compressors, reduced venting of associated gas, and replacement of high-emitting pneumatic devices.
- **Abatement by Segment** – The majority of the projected emissions are found in the oil and gas producing segments and the gas transmission segment. These three segments account for almost 70% of the projected reductions.
- **Co-Benefits** – Reducing methane emissions will also reduce conventional pollutants. The methane reductions projected here would also result in a 44% reduction in volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) associated with these methane emissions.

There are several caveats to the results:

- The 2011 EPA inventory is the best starting point for analysis, but it is based on many assumptions and some older data sources. Although the inventory is improving with new data, it is designed to be a planning and reporting document and is imperfect, especially at the detailed level, for a granular analysis of this type.
- Emission mitigation cost and performance are highly site specific and variable. The values used here are estimated average values.
- The analysis presents a reasonable estimate of potential cost and magnitude of reductions within a range of uncertainty.

Appendix A. Additional Sensitivities

This Appendix presents additional analytical results and sensitivities for the base case results. These include:

- **Alternative gas prices** – Figures A-1 and A-2 show the MAC Curve for gas prices at $3/Mcf and $5/Mcf. As expected, the lower gas price results in a higher reduction cost ($1.48/Mcf of methane reduced) due to the reduced value of recovered gas. A higher gas price results in a lower reduction cost (-$0.15/Mcf of methane reduced) compared to the baseline value of $0.66/Mcf of methane reduced at $4/Mcf. The change in gas price only affects those measures and segments that can monetize the reductions.
- **Alternative discount rate/cost of capital** – Figure A-3 shows the base case with a higher discount rate of 15%. The discount rate increases the cost of capital-intensive measures. The cost of reduction is $1.01/Mcf of methane reduced at the higher discount rate.
- **Results expressed as dollars per ton of CO_2 equivalent** – Figures A-4 and A-5 show the results on a $/tonne of CO_2e basis. The baseline measures result in a reduction of 79 MMtonnes of CO_2e at a cost of $1.38/tonne CO_2e at a 100 year global warming potential (GWP) of 25. Using a 20 year GWP of 72 increases the estimated reduction to 226 MMtonnes of CO_2e at a cost of $0.48/tonne CO_2e.
- **Results expressed as dollars per metric tonne of methane** – Figure A-6 shows the base case results on a $/tonne of methane basis. The baseline measures result in a reduction of 3.1 MMtonnes of methane at a cost of $35/tonne of methane.
- **Results expressed as a percent of methane emissions from on-shore gas operations** – Figure A-7 shows the base case results as a percent of gross methane withdrawals. Methane emissions from onshore gas operations in 2018 are projected to be approximately 1.3% of gross methane withdrawals. The reductions identified in this analysis would reduce the emissions to just less than 0.8% of gross withdrawals.

Figure A-1 - Sector MAC Curve - $3/Mcf Gas Price

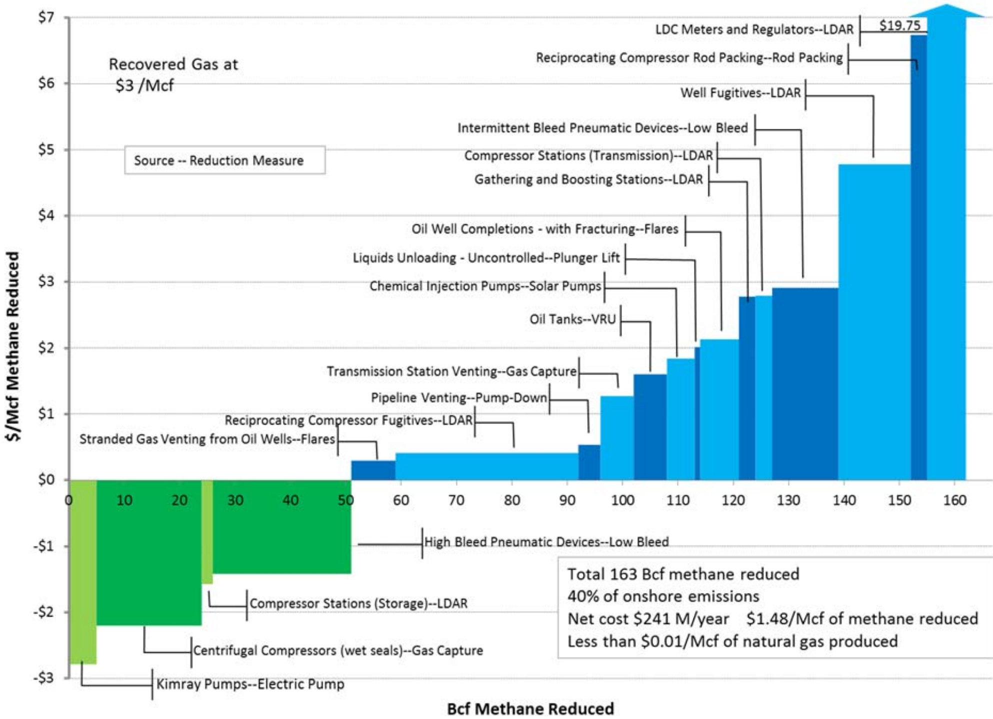


Figure A-2 - Sector MAC Curve - $5/Mcf Gas Price

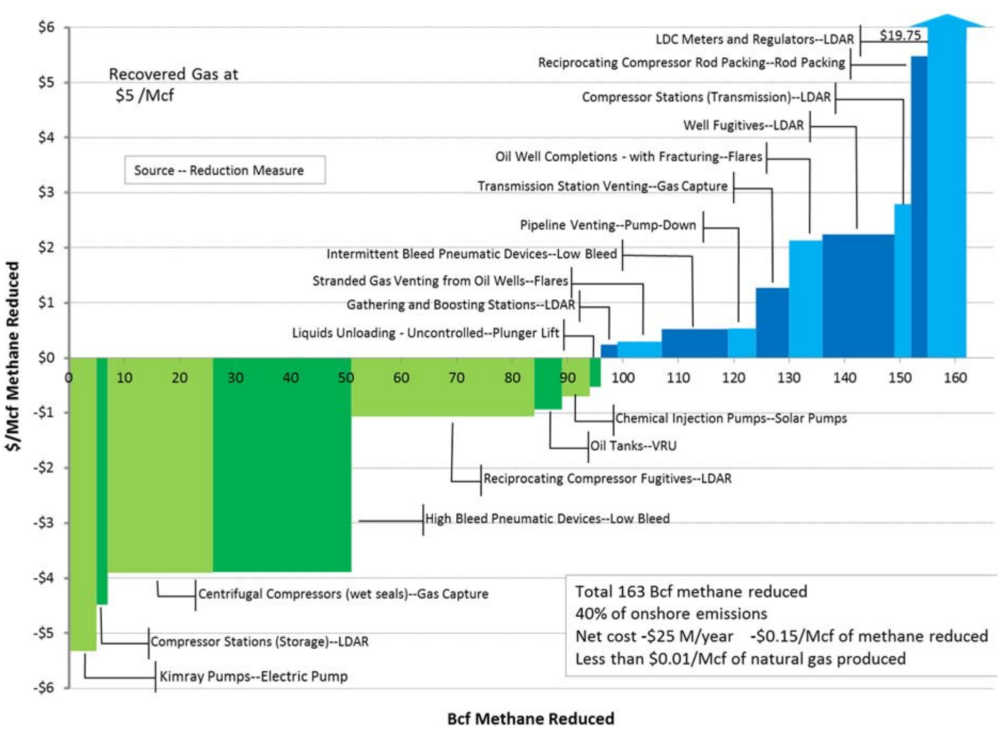


Figure A-3 - Sector MAC Curve – 15% Discount Rate

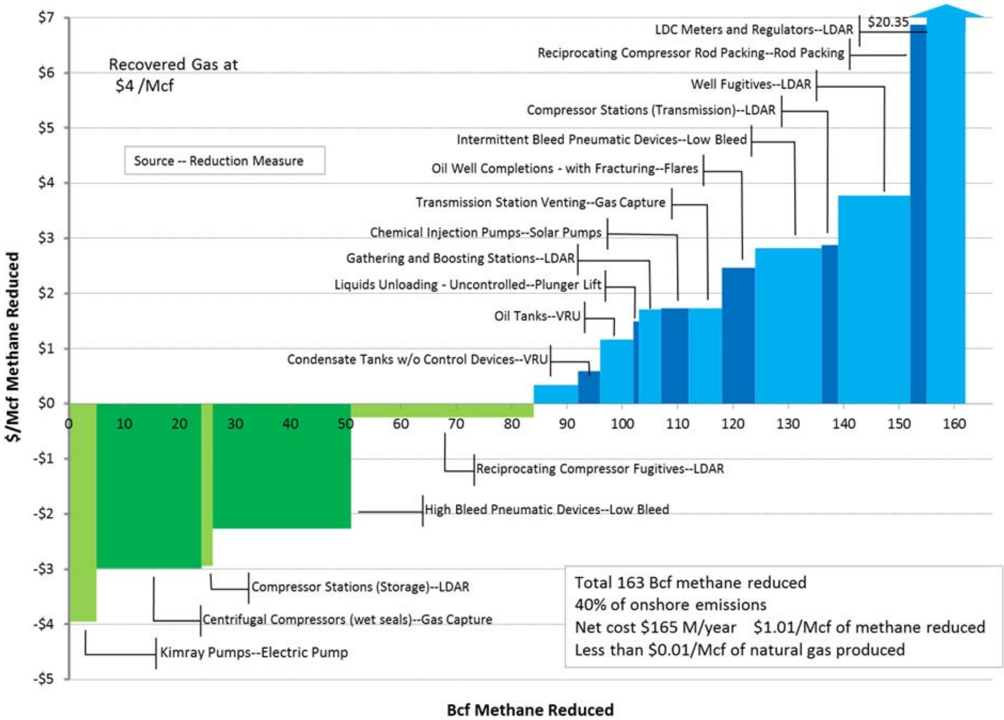


Figure A-4- Sector MAC Curve – $/tonne CO_2e – 100 Year GWP = 25

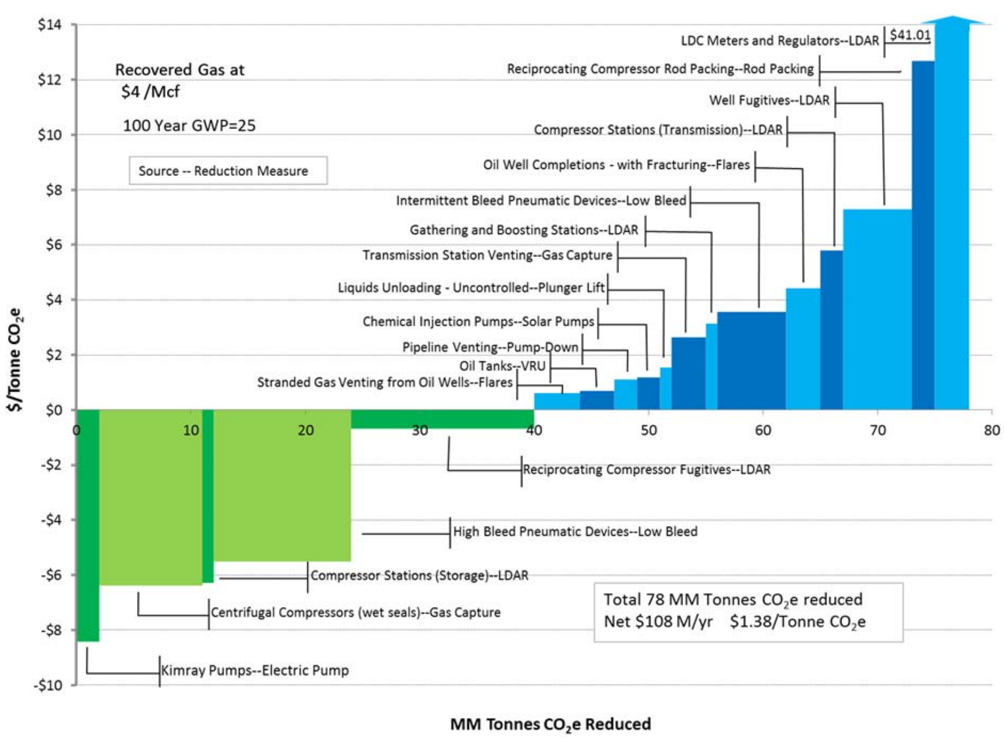


Figure A-5- Sector MAC Curve – \$/tonne CO_2e – 20 Year GWP = 72

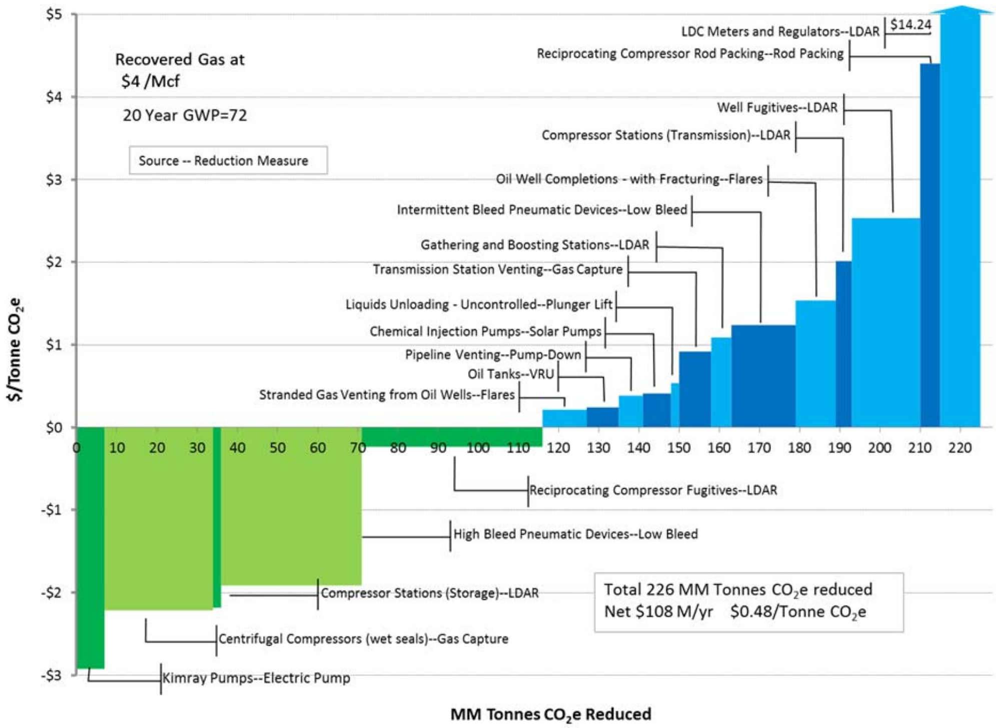


Figure A-6- Sector MAC Curve - \$/tonne Methane Reduced

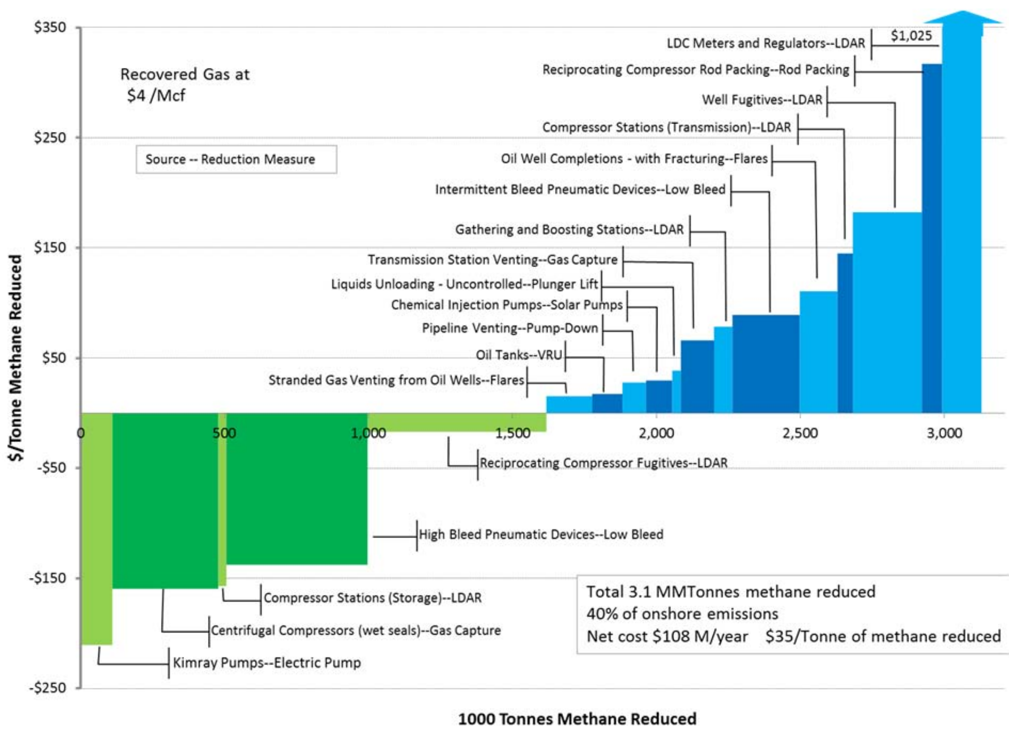
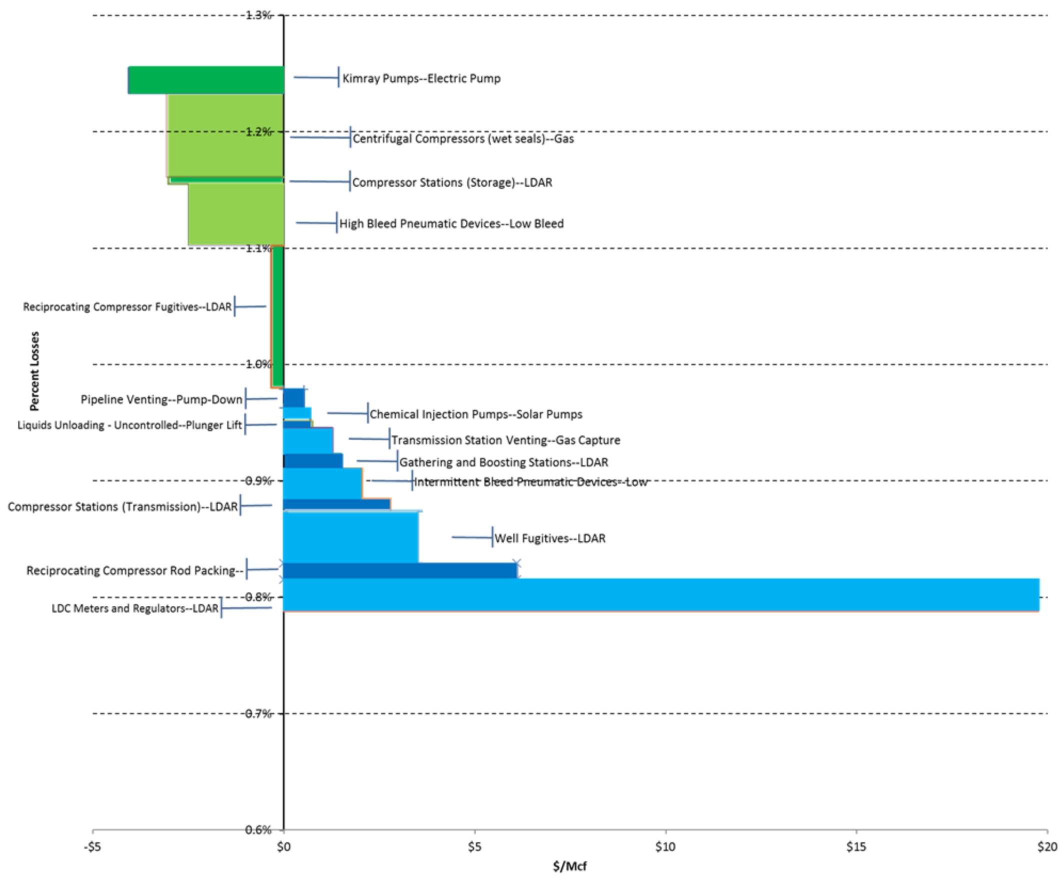


Figure A-7- "Percent Leakage" Analysis



Appendix B. Development of the 2011 Emissions Baseline

B.1. Overview

The analysis of methane emission reduction potential takes as its starting point the methane portion of the Natural Gas and Petroleum Systems section of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*. This inventory represents the most robust, comprehensive data set of its kind. However, because the EPA Inventory is intended as a planning document – not a standalone source for granular economic analysis – ICF created an alternative 2011 Baseline based on the EPA Inventory structure and other data sources. This was not a complete update of the 2011 EPA inventory, which was beyond the scope of this project, but an update of any sections for which new or better data could be readily identified.

While the Baseline applied changes and adjustments to the structure of the data and many source categories, causing increases and decreases, the overall effect was an increase of just 2.4% (10 Bcf) in the net estimated methane emissions from the oil and gas sectors compared to the 2011 EPA Inventory. The estimated emissions from the natural gas sector were reduced by over 2% (10 Bcf) while the emissions from the oil sector increased by nearly 26% (20 Bcf) compared to the 2011 EPA baseline (see table below).

B.2. Summary of Changes

The starting point for the 2011 Baseline was the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*[35] published in April 2013, which estimates 436 billion cubic feet (Bcf) or 8.4 million metric tonnes (MMTonnes) of methane emissions for the petroleum and natural gas sectors[36]. The Natural Gas sector and the Petroleum sector are further divided in the inventory into the various segments for the natural gas sector (Gas Production, Gathering and Boosting, Gas Processing, Gas Transmission, Gas Storage, LNG Import/Export, and Distribution) and the petroleum sector (Oil Production, Transportation, and Refining).

The Inventory breaks out methane emissions for approximately 200 sources, and calculates uncontrolled emissions using activity factors (e.g., equipment counts) multiplied by emission factors (average emissions from each source) to estimate the total emissions. The total uncontrolled emissions are offset by emission reductions reported primarily from the EPA's voluntary Natural Gas STAR Program, plus additional reductions from other sources, such as state regulations.

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[35] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2011", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

[36] While the 2013 edition of the Inventory was the current version at the time the study was initiated, EPA has since released the draft of the 2014 edition. However this study does not address that newer version of the Inventory.

Summary of 2011 Emissions Baseline

Segment	2011 EPA Inventory		ICF 2011 Baseline		Change (%)
	(Million tonnes CH_4)	(Bcf CH_4)	(Million tonnes CH_4)	(Bcf CH_4)	
Natural Gas					
Gas Production	2.2	113	2.0	103	-9%
Gathering and Boosting	0.5	24	0.8	43	80%
Gas Processing	0.9	48	0.8	44	-9%
Gas Transmission	1.7	87	1.4	75	-14%
Gas Storage	0.3	17	0.3	15	-11%
LNG	0.1	5	0.1	6	22%
Gas Distribution	1.3	69	1.3	69	0%
Petroleum					
Oil Production	1.4	72	1.8	92	27%
Oil Transportation	< 0.1	< 1	< 0.1	< 1	1%
Oil Refining	< 0.1	1	< 0.1	1	0%
Total Net Gas Emissions	7.0	362	6.8	353	-2%
Total Net Oil Emissions	1.4	73	1.8	93	26%
Total Emissions	**8.4**	**436**	**8.6**	**446**	**2.4%**

During the development of 2011 Baseline, ICF focused on updating these factors for numerous sources. The changes that were made, which are documented below, came from several publically available references. The most common source of new information was the U.S. EPA's mandatory Greenhouse Gas Reporting Rule (GHGRP) subparts C (combustion from stationary sources) and W (methane emissions from petroleum and natural gas systems). ICF also used information and data from the U.S. Energy Information Administration (EIA), EPA's 1996 GRI study of methane emissions[37], the EPA Manual

[37] "Methane Emissions from the Natural Gas Industry" http://epa.gov/gasstar/tools/related.html

of Emission Factors AP-42[38], various state energy and environmental departments, and the EDF/University of Texas methane measurement study[39]. Much of this information, in particular the data from subpart W was not available at the time that the EPA Inventory was originally developed.

B.3. Natural Gas Inventory

The largest change to the structure of the Natural Gas segment in the 2011 Baseline was breaking out the Gathering and Boosting segment. This is the segment between onshore Production and either Gas Processing or Gas Transmission. This segment is included in the onshore Production segment of the EPA Inventory based on the 1996 GRI measurement study rather than being fully broken out as a separate segment. In this study, some sources were moved from Production to the Gathering and Boosting segment in order to allow them to be analyzed separately for this segment and new emissions estimates, for some sources underrepresented in the 2011 EPA inventory, were added. The major source additions were new estimates of compressor and pneumatic device emissions. In addition, emissions from condensate tanks were moved from the Production segment to the Gathering and Boosting segment.

B.3.1. Gas Production

B.3.1.1. Natural Gas Well Counts

Up until the U.S. Inventory published in April 2013, natural gas well counts were obtained from the *World Oil* magazine. The *World Oil* magazine provides the total well count in the U.S., and then hydraulically fractured and non-hydraulically fractured wells were split out in the Inventory using data gathered from state energy agencies. In the EPA Inventory published in April 2013, the well counts were obtained from DI Desktop™, based on the HPDI™ database. While the HPDI™ database gives a much more accurate ratio of hydraulically fractured wells to non-hydraulically fractured wells, it does not contain all of the operating wells in the U.S. (The *World Oil* magazine lists about 5% more wells than are in HPDI™). Therefore, the well counts were updated by increasing the overall well count by 5%. This well count also affected the count of associated well equipment, as detailed in section B.3.1.3.

B.3.1.2. Well Head Fugitives

Fugitives from well heads were separated by region (Eastern U.S. versus Western U.S.) in the EPA Inventory. In the 2011 Baseline, this emissions source uses a new single national emission factor. The emission factor was developed from the work done by the University of Texas for EDF on fugitive emissions from well sites. From this study, any identifiable well head emissions (i.e., emissions from the well itself, not the associated equipment) were grouped together and then divided by the well count at

[38] http://www.epa.gov/ttn/chief/ap42/index.html

[39] Allen, David, et. al., "Measurements of Methane Emissions at Natural Gas Production Sites in the United States". 10.1073/pnas.1304880110

those sites to determine an overall per well emission factor. The updated factor was 97.6 standard cubic feet per day (scf/day) of whole gas emissions, compared to the Eastern and Western factors of 9.0 and 46.2 scf/day of whole gas, respectively.[40] This new factor was then applied to the updated well count (see section B.3.1.1). These changes resulted in a 420% increase in emissions, to 14 Bcf.

B.3.1.3. Heaters, Separators, Dehydrators, and Meters/Piping (Well Fugitives)

The 1996 GRI study provides separate emission factors for the eastern and western U.S. for these sources, with the eastern factors substantially lower than the western factors. These emission factors were kept the same for the 2011 baseline year, but changed for the 2018 projection, as detailed in section C.4.1. The big change to these sources was to update the activity factors in order to correspond with new the well counts (in the EPA Inventory, the well counts drive the equipment counts for these sources). This change resulted in a collective 4% increase in emissions for these sources to 15 Bcf.

B.3.1.4. Gas Well Completions

Gas well completions are broken out for hydraulically fractured wells and non-hydraulically fractured wells. The emissions from these two categories in the EPA Inventory were compared to the emissions from subpart W and found to differ quite dramatically. The EPA Inventory uses whole gas emission factors of 9,000,000 scf/completion for uncontrolled hydraulically fractured wells and 733 scf/completion for non-hydraulically fractured wells. The emissions data from subpart W, from both the 2011 and 2012 reporting cycles, was used to develop new emission factors. These factors were derived by aggregating the total emissions from the different completion types and then dividing by the count of completions. These factors include emissions reductions during the completion process and so are not directly comparable to the EPA factor for uncontrolled completions. This analysis derived methane emission factors of 1,500,000 scf CH_4/completion for hydraulically fractured wells and 70,000 scf CH_4/completion for non-hydraulically fractured wells.

Both the EPA Inventory and the 2011 Baseline apply Gas STAR, regulatory, and other reductions (in the form of reduced emission completions (RECs) and "green" completions) to the uncontrolled emissions from hydraulically fracture well completions. Because of this, the EPA emission factor for hydraulically fractured well completions (9,000,000 scf whole gas/completion) was kept, but the application of the various reductions brought the overall emissions down to the level suggested by the subpart W derived emission factor, for a net level of emissions of 13 Bcf from hydraulically fractured well completions. For non-hydraulically fractured well completions, the subpart W derived emission factor was adopted.

The activity factors for both of these sources were updated using completions data from the most recent API Quarterly Completions Report. These values are 8,480 hydraulically fractured well

[40] These values are listed in terms of methane in emissions in the EPA Inventory. They are 7.1 and 36.4 scf/day of methane, respectively. They were converted to whole gas using the EPA volumetric methane content of 78.8%.

completions and 4,592 non-hydraulically fractured well completions for 2011, compared to the EPA values of 8,077 hydraulically fractured well completions and 799 non-hydraulically fractured well completions. Using these updated factors, the emissions from hydraulically fractured well completions were reduced by about 55% to 13 Bcf, and emissions from non-hydraulically fractured well completions increased to 0.3 Bcf.

B.3.1.5. Well Drilling

The number of wells drilled was updated to reflect the number of completions in 2011, as described in section B.3.1.4. Each well completion was counted as one well drilled, and this decreased the count of wells drilled from 14,807 in the EPA Inventory to 13,072 wells drilled in the 2011 Baseline. This resulted in a net decrease in emissions from well drilling by 12% to 0.03 Bcf.

B.3.1.6. Well Testing

This source was not included in the published EPA Inventory, but it is included in subpart W of the GHGRP. Therefore, emission and activity factors were developed from the 2011 and 2012 subpart W data and were included in the 2011 Baseline. The subpart W derived emission factor is 95,000 scf/well tested, and the reported number of wells tested in subpart W is 11,111 per year. It was assumed that subpart W covers 85% of the reporters[41], so the activity factor was increased to 13,072 wells tested per year. The Well Testing methane emissions totaled over 1 Bcf.

B.3.1.7. Pneumatic Devices

Pneumatic devices in the published Inventory were listed as a single category and used a single emission factor of 345 scf/day (126 Mcf/year). However, pneumatic devices are reported in subpart W in three categories: low bleed, intermittent bleed, and high bleed devices. In order to break out the devices into the respective categories, the emissions data reported to subpart W for 2011 and 2012 were analyzed. From each device type's emissions, the count of each device type was back calculated using the prescribed emission factor in subpart W. This analysis gave a ratio of 10% high bleed, 50% intermittent bleed, and 40% low bleed devices.

The "intermittent bleed" category covers a variety of different types of devices with different emission characteristics and is not well-characterized either in the subpart W data or other sources of emission data. Some of these, as characterized in the subpart W emission factors, have a relatively high emission factor, while others are much lower. For this reason, the intermittent devices were further segregated into two categories: dump valves and non-dump valve intermittent devices. The dump valves represent devices that do not have a continuous bleed and generate emissions only when actuating, resulting in far fewer emissions. These types of devices are generally found as level controllers in separators. In order to obtain the number of dump valves in operation, the number of intermittent bleed devices was

[41] This assumption was derived during the development of subpart W and is applied thoughout this analysis.

compared to the count of separators. Assuming that approximately 80% of separators have a lower-emitting intermittent bleed dump valve yielded an estimate that approximately 75% of the total intermittent bleed devices were dump valves.

Additionally, the overall count of pneumatic devices was updated, to reflect the updated well counts, as described in section B.3.1.1, and to better characterize the Gathering and Boosting sector. The count of pneumatic devices is driven off of the well counts in the 2011 EPA Inventory, and the overall activity factor driver is 0.94 pneumatic devices per well. This factor was compared to the result of a study performed by API/ANGA[42], which characterized the pneumatic devices in the Production and Gathering and Boosting sectors. The activity factor driver developed in the study was 0.99 pneumatic devices per well, which matched closely with the driver from the EPA Inventory. Therefore, no change was made there. However, the study also found that there were an additional 8.6 pneumatic devices per Gathering/Compressor Station. Since these devices were not accounted for in the EPA Inventory, this factor was used to add in the devices associated with Gathering Stations, which are further described in section B.3.2.3. This change resulted in an additional 23,000 pneumatic devices, which were subject to the same split as described above and are included in the Gathering and Boosting Segment.

Updated emission factors were obtained for the different pneumatic device types from an analysis of subpart W data. Total emissions from each device type were divided by the device count (obtained as described above) to obtain national emission factors for each type of pneumatic device. The emissions factors were determined to be 320 Mcf/yr/device, 120 Mcf/yr/device, and 11 Mcf/yr/device for high bleed, intermittent bleed, and low bleed devices, respectively. For intermittent bleed devices, it was assumed that dump valves have approximately 80% fewer emissions than non-dump valve intermittent bleed devices based on discussions with industry stakeholders, and therefore were assigned an emission factor of 20 Mcf/yr/device. The count of devices was updated as well in order to correspond with the updated well count described in section B.3.1.1. Overall, these changes resulted in a 41% increase in emissions from pneumatic devices to over 26 Bcf.

B.3.1.8. Chemical Injection (Pneumatic) Pumps

The count of chemical injection pumps was updated to reflect the updated well counts, as described in section B.3.1.1. Further, in the EPA Inventory, there is a Gas STAR reduction associated with pneumatic pumps. However, in the EPA Inventory, this is only applied to Kimray pumps and not chemical injection pumps. In the 2011 Baseline, these reductions are also allocated, in proportion, to chemical injection pumps. These reductions totaled just less than 2 Bcf of methane. These changes resulted in a net increase of emissions by about 2% to over 3 Bcf.

[42] API and ANGA. “Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production.” Found online at: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf

B.3.1.9. Dehydrators and Kimray Pumps

Emissions from dehydrator vents and Kimray Pumps were compared to the emissions reported in subpart W, and the subpart W emissions were shown to be much lower than the estimated emissions in the EPA Inventory. However, it was determined that subpart W is underreporting emissions because many dehydrators would fall into the Gathering and Boosting segment of the industry, which is not covered by subpart W. Therefore, the dehydrator emissions reported to subpart W were allocated to the Gas Production segment, and the remaining emissions from the EPA Inventory were moved to the new Gathering and Boosting segment. Overall, no change to the emission factor or activity factor occurred. However, as described in section B.3.1.8, Gas STAR reductions for pneumatic pumps were originally only allocated to Kimray pumps in the EPA Inventory, but were broken out to include chemical injection pumps in the 2011 Baseline. Therefore, the total Gas STAR reductions allocated to Kimray pumps decreased to just under 7 Bcf, while the net emissions from dehydrators and Kimray pumps increased 22% to nearly 17 Bcf.

B.3.1.10. Condensate Tanks

Data reported to subpart W was used to update the emission factors for condensate tank venting. The data pulled from subpart W was on a state basis and included average API gravity, separator pressure, and separator temperature. This data was then used to run simulations through API's E&P Tank™ software in order to develop new emission factors. The emission factors for each state were then averaged into emission factors for each NEMS region, with the only missing region being the west coast, which used a country-wide average instead. The new emission factors, shown in the table below, were then used to calculate updated emissions.

Condensate Tank Emission Factor Changes

Region	Emission Factor (scf/bbl)	
	EPA Inventory	2011 Baseline
Northeast	21.9	23.0
Gulf Coast	21.9	16.9
Midcontinent	302.8	15.0
Southwest	302.8	10.8
Rocky Mountain	21.9	39.0
West Coast	21.9	21.0
Alaska	N/A	21.0

To stay consistent with the EPA Inventory methodology, it was assumed that 50% of the tanks had control measures in place and that the measures were 80% effective. This resulted in a decrease in condensate tank emissions by 80% to 2 Bcf. These emissions were moved to the Gathering and Boosting segment.

B.3.1.11. Dump Valve Venting

This source was not included in the published EPA Inventory, but it is included in subpart W of the GHGRP. Therefore, emission and activity factors were developed from the 2011 subpart W data and were included in the 2011 Baseline. The subpart W derived emission factor is 15,000 scf/year/leaking valve, and the reported number of leaking dump valves to subpart W is 7,916. It was assumed that subpart W covers 85% of the reporters, so the activity factor was increased to 9,313. The dump valve venting methane emissions totaled over 0.1 Bcf.

B.3.1.12. Gas Well Workovers

Emissions from gas well workovers for both hydraulically fractured and non-hydraulically fractured wells were compared between the published EPA Inventory and the data reported to subpart W. The data reported to subpart W suggested that emissions from hydraulically fractured well workovers is lower than in the EPA inventory, while emissions from non-hydraulically fractured well workovers are higher. Therefore, the data from subpart W was used to update both the emission and activity factors. The new emissions were calculated as 790,000 scf/workover for hydraulically fractured well workovers and 135,000 scf/workover for non-hydraulically fractured well workovers. The number of workovers reported to subpart W was 1,060 for hydraulically fractured wells and 11,663 for non-hydraulically fractured wells. It was assumed that subpart W covers 85% of the reporters, so the activity factors were increased to 1,247 and 13,721, respectively. For wells with hydraulic fracturing, emissions dropped about 90% to 1 Bcf. For non-hydraulically fractured wells, emissions increased to nearly 2 Bcf.

While determining the factors from hydraulically fractured gas wells in subpart W was straightforward, the non-hydraulically fractured gas well analysis was less clear. For non-hydraulically fractured gas wells, emissions from completions and workovers were lumped together, and the only way to separate them out was to use the reported number of "Completion Venting Days" in subpart W. Therefore, only those production sites that reported no completion venting days but still reported emissions were used to determine the factors for gas well workovers without hydraulic fracturing.

B.3.1.13. Liquids Unloading (Gas Well Clean Ups)

Data reported to subpart W for 2011 and 2012 was used to develop new activity and emission factors for wells with liquids unloading. From the subpart W data analysis, the number of wells venting with plunger lifts was reported to be 37,643 and the number of wells venting without plunger lifts was reported to be 26,451. It was assumed that subpart W covers 85% of reporters, so the number of venting wells was increased to 44,286 and 31,113, respectively.

The emission factors were also updated using the data reported to subpart W for 2011 and 2012. The total emissions for each venting well type (plunger lift versus non-plunger lift) were divided by the total number of reporting wells in order to obtain the new emission factors. From this analysis, the calculated emission factors were 277,000 scf/venting well for wells with plunger lifts and 163,000 scf/venting well for wells without plunger lifts.

Using these updated activity factors and emission factors results in a net increase of methane emissions by 30% to 17 Bcf.

B.3.2. Gathering and Boosting

This sector was previously included as part of the Production sector, but has been broken out in this analysis so that it could be separately analyzed and because it appeared to be underrepresented in the published Inventory. This sector in the in the 2011 Baseline contains emissions from compressors (both reciprocating and centrifugal), compressor stations, pneumatic devices, and pipelines. Some other supporting equipment types were left in their respective sectors, as found in the EPA Inventory.

B.3.2.1. Compressors

The published EPA Inventory currently calculates the count of compressors in each NEMS region based on the number of gas wells in that region. The vast majority (>99%) of these compressors are estimated to be small compressors and emissions are calculated using an emission factor of 267 scf /day. A very small number of compressors are estimated to be large compressors and use an emission factor developed for transmission compressors of 15,205 scf /day. Both of these emission factors come from the 1996 EPA/GRI study. Using the background data from this study, it was determined that the average size of a transmission compressor in the GRI study was 1,600 horsepower.

In order to update the emission factors for this source, state energy agencies were contacted in an attempt to obtain a list of permitted engines in the production sector of the petroleum and natural gas industry. From the outreach, five states provided detailed engine counts. These states were Texas, Colorado, Wyoming, Oklahoma, and Pennsylvania. The engines were sorted so that only production and gathering compressors remained. The compressors were then split into small and large compressor groups using a 1,600 hp threshold, as determined from analysis of the raw data from the 1996 EPA/GRI study. The state data showed a much higher share of large compressor engines than assumed in the EPA Inventory methodology. A weighted average emission factor, using the emission factors from the EPA Inventory, was then developed from this data. The new emission factor for all gathering compressors was calculated at 1,980 scf/day/compressor.

An additional update to the reciprocating compressors emission factor was applied in order to break out emissions from compressor seals versus the other compressor fugitives. The U.S. Inventory uses a single emission factor to cover all fugitive emissions from reciprocating compressors. However, the source document for the emission factor (the 1996 GRI Report) breaks out the emissions from the separate sources on a compressor, including blowdown lines, PRVs, open ended lines, compressor seals, and miscellaneous. The factor for compressor seals was separated out from the other factors in order to break emissions into two categories: “Reciprocating Compressors – Non-Seals” (75%) and “Reciprocating Compressors – Seals” (25%).

The state data was also used to develop new activity factors for reciprocating compressors. The compressor count was then scaled up from these five states using the EPA Inventory ratio of compressors in these five states to the national count of compressors to obtain a new national reciprocating compressor count of 15,687. Accounting for all of these changes, the net change in emissions from reciprocating compressors was an increase of 166% to 11 Bcf.

Subpart W also reported the use of wet seal centrifugal compressors in the upstream sector. This data was used to create a new emission category for wet seal centrifugal compressors. The number of reported compressors was 162, and assuming that subpart W covers 85% of reporters, the activity factor was set at 191. The subpart W emission factor, 12,000,000 scf/year/compressor, was also used in the 2011 Baseline. The emissions from this source were over 2 Bcf.

B.3.2.2. Compressor Exhaust (Gas Engines and Gas Turbines)

The exhaust from compressor engines and turbines contains some unburned methane. The activity factor for these two emissions sources in the published Inventory is based on the total horsepower-hours of the equipment. However, the U.S. EIA publishes the amount of natural gas used as “Lease Fuel,” which is fuel burned at natural gas production sites. This fuel volume was used as the new activity factor. The analysis assumed 80% of the lease fuel was consumed in engines and turbines and the breakdown between engines and turbines was determined to be 99% to 1%, respectively, using the breakdown of compressors reported to subpart W for production.

The emissions factors were updated using emissions factors from the EPA’s manual of emission factors (“AP-42”). Since AP-42 lists 3 separate emission factors for engines (two stroke lean-burn, four stroke lean-burn, and four stroke rich-burn), a combined emission factor was developed based on the data obtained from the state energy agencies, as described in section B.3.2.1. Four of the states either listed the engine type or provided enough data to determine the engine type for the compressors listed. This data set, which contained nearly 10,500 compressors/engines across all sectors of the industry, was used to determine the breakout of engine types: 10% two stroke lean-burn, 34% four stroke lean-burn, and 56% four stroke rich-burn. These ratios were used to give an overall emission factor for engines of 332 kg CH_4 per MMscf gas burned (17,280 scf CH_4/MMscf gas burned). The emission factor for turbines, 4.0 kg CH_4 per MMscf gas burned (208 scf CH_4/MMscf gas burned), was listed directly in AP-42 and used as-is. These modifications resulted in a 7% decrease in emissions to just over 10 Bcf.

B.3.2.3. Gathering and Boosting Stations

Formally called “Large Compressor Stations” in the EPA Inventory, this count of stations was determined from the number of large compressors in the Inventory, which as stated in section B.3.2.1 was very small. The updated gathering station count was determined using an assumption that each processing plant has 3 gathering stations that feed into it. This resulted in an increase of stations to over 2,700. The emissions also increased substantially, rising to over 8 Bcf.

B.3.2.4. Dehydrators and Kimray Pumps

See section B.3.1.9 for explanation.

B.3.2.5. Pipeline Leaks, Pipeline Blowdowns, Compressor Starts, and Compressor Blowdowns

These emissions were moved from Production to Gathering and Boosting to better represent the breakout of emissions in the industry. Also, the number of compressors was updated for compressor starts and blowdowns in order to match the number of compressors from the state data analysis, as described in section B.3.2.1. The emission factors for these sources did not change, but the overall methane emissions decreased by 2% to 9 Bcf.

B.3.3. Gas Processing

B.3.3.1. Gas Plant Fugitives

The gas plant count of 585 gas processing plants in the published Inventory comes from the *Oil and Gas Journal*. This source lists only plants that contain fractionation equipment. However, there are large gas treatment plants that do not contain fractionation equipment and are covered by subpart W. The EIA also maintains a list of gas processing facilities. Therefore, the count of plants was compared between these three sources to find the unique values, and it was determined that there are 909 gas processing and treatment facilities in the U.S. This resulted in a 55% increase in emissions estimated for this source category to nearly 3 Bcf.

B.3.3.2. Reciprocating Compressors

An update to the reciprocating compressor emission factor was made in order to break out emissions from compressor seals versus the other compressor fugitives. This change is described in section B.3.2.1.

B.3.3.3. Gas Engine and Turbine Exhaust

The activity factor for these two emissions sources in the published Inventory is based on the total horsepower-hours of the equipment. However, the U.S. EIA publishes the amount of natural gas used as "Plant Fuel," which is fuel burned in natural gas processing plants. This fuel volume was used as the new activity factor with an assumed 80% of the fuel being consumed in engines and turbines in a typical processing plant. Further, the breakdown between engines and turbines was determined to be 46% to 54%, respectively, using the current horsepower-hour ratios in the published Inventory.

The emissions factors were also updated, as described in section B.3.2.2. In this case the emissions were reduced by 74% for gas engines and 87% for turbines compared to the published inventory.

B.3.3.4. Pneumatic Devices

For processing plants, pneumatic devices are not broken out by bleed rate, as neither the EPA Inventory nor subpart W has this information. Instead, the activity factor for pneumatic devices in processing is the number of processing/gas treatment plants. This was updated to the 909 plants, as described in section B.3.3.1. This resulted in an increase in emissions of 55% to nearly 0.2 Bcf. (Most processing plants are believed to use instrument air instead of gas-driven pneumatics.)

B.3.3.5. Blowdowns/Venting

The activity factor for blowdowns/venting in processing is the number of processing plants. This was updated, as described in section B.3.3.1. However, the EPA Inventory also details Gas STAR reductions from this source. Overall, the updated net methane emissions increased 190% to 2 Bcf.

B.3.4. Gas Transmission

B.3.4.1. Pipeline Leaks

The total number and breakout of transmission pipeline miles in the U.S. was updated using data from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The PHMSA data showed a lower value for transmission pipeline miles from 304,606 in the EPA Inventory to 298,750 in the 2011 Baseline. The breakout was also used to assign the pipeline miles to the respective regions. This reduction in pipeline miles caused a reduction in emissions of 2%, to 0.2 Bcf. The pipeline miles are used to drive the number of compressors and compressor stations in the transmission segment. These values were updated accordingly.

B.3.4.2. Transmission Compressor Stations

The number of compressor stations is driven off of the pipeline miles in the U.S. Inventory, so the change in pipelines miles, as detailed in section B.3.4.1, caused the number of reciprocating compressors to change from 1,808 to 1,768, resulting in an emissions decrease of just over 2%.

B.3.4.3. Reciprocating Compressors

Reciprocating compressor count is driven off of the pipeline miles in the U.S. Inventory, so the change in pipelines miles caused the number of reciprocating compressors to change from 7,270 to 7,111, resulting in an emissions decrease of over 2%. Further, an update to the reciprocating compressor emission factor was made in order to break out emissions from compressor seals versus the other compressor fugitives. This change is described in section B.3.2.1.

B.3.4.4. Centrifugal Compressors

Centrifugal compressor count is driven off of the pipeline miles in the U.S. Inventory, so the change in pipelines miles caused the number of reciprocating compressors to change from 654 to 648, resulting in an emissions decrease of over 2%.

B.3.4.5. Engine and Turbine Exhaust

The activity factor for these two emissions sources in the published Inventory is based on the total horsepower-hours of the equipment. However, the U.S. EIA publishes the amount of natural gas used as “Pipeline Fuel,” which is fuel burned in natural gas transmission pipelines and at storage facilities. This fuel volume was used as the new activity factor. The breakdown between transmission and storage was done using the current horsepower-hours listed in the published Inventory, which gave 90% to transmission and 10% to storage. These horsepower-hours ratios were also used to determine the amount of fuel sent to engines versus turbines. For transmission, the fuel breakdown between engines and turbines was determined to be 81% to 19%, respectively. For storage, the fuel breakdown between engines and turbines was determined to be 74% to 26%, respectively. The emissions factors were also updated, as described in section B.3.2.2. In this case the emissions decreased by 26% for gas engines and decreased 63% for turbines.

B.3.4.6. Pneumatic Devices

Pneumatic devices were broken out the same as described in section B.3.1.7. This analysis led to a breakdown of 15% high bleed, 75% intermittent bleed, and 10% low bleed in the transmission segment. Updated emission factors were also obtained from subpart W data analysis and were determined to be 155 Mcf/yr/device, 20 Mcf/yr/device, and 12 Mcf/yr/device, respectively. This breakout resulted in a 74% decrease in emissions to just under 3 Bcf.

B.3.4.7. Dump Valve Leakage

This source was not included in the published EPA Inventory, but it is included in subpart W of the GHGRP. Therefore, emission and activity factors were developed from the 2011 subpart W data and were included in the 2011 Baseline. The subpart W derived emission factor is 950,000 scf/year/leaking dump valve, and the reported number of leaking dump valves to subpart W is 318. It was assumed that subpart W covers 85% of the reporters, so the activity factor was increased to 374. The dump valve leakage methane emissions totaled over 0.3 Bcf.

B.3.4.8. Pipeline Venting

The activity factor for pipeline venting was updated, as described in section B.3.4.1. This resulted in a decrease in emissions of 3%.

B.3.4.9. Transmission Station Venting

The activity factor for transmission station venting was updated, as described in section B.3.4.1. This resulted in a decrease in emissions of 2%.

B.3.5. Gas Storage

B.3.5.1. Reciprocating Compressors

An update to the reciprocating compressor emission factor was made in order to break out emissions from compressor seals versus the other compressor fugitives. This change is described in section B.3.2.1.

B.3.5.2. Pneumatic Devices

Pneumatic devices were broken out the same as described in section B.3.1.7. This analysis led to a breakdown of 40% high bleed, 50% intermittent bleed, and 10% low bleed in the transmission sector. Updated emission factors were also obtained from subpart W data analysis and were determined to be 155 Mcf/yr/device, 20 Mcf/yr/device, and 12 Mcf/yr/device, respectively. This breakout resulted in a 55% decrease in emissions to just over 1 Bcf of methane.

B.3.5.3. Engine and Turbine Exhaust

The activity factor for these two emissions sources was updated, as described in section B.3.4.5. The emissions factors were also updated, as described in section B.3.2.2. In this case the emissions decreased by 20% for gas engines and decreased 73% for turbines.

B.3.6. Liquefied Natural Gas (LNG)

B.3.6.1. Import/Export Terminals

LNG import/export terminals were increased from 8 in the EPA Inventory to 12 in the 2011 Baseline from an analysis of operating terminals listed in the Federal Energy Regulatory Commission's (FERC) website. Part of this increase has to do with the fact that the EPA Inventory discounts the total number of terminals by 30%, resulting in a reduced activity factor. This reduction was taken out of the 2011 Baseline. This increase in terminals increased station fugitives and station venting by 56% to nearly 0.2 Bcf.

B.3.6.2. Storage Stations

No changes were made to the count of storage stations.

B.3.6.3. Reciprocating Compressors (Import/Export and Storage)

For Import/Export Terminals, the count of reciprocating compressors was updated to reflect the new station count using activity factor drivers from the EPA Inventory. For Storage Stations, the EPA Inventory differentiates between "Complete Storage Faculties" and "Satellite Storage Faculties" in order to calculate the number of compressors. However, there was insufficient data to maintain this distinction in the 2011 Baseline, which caused the count of compressors to increase from 270 to 368. An update to the reciprocating compressor emission factor was made in order to break out emissions from compressor seals versus the other compressor fugitives. This change is described in section B.3.2.1. These changes caused an increase in compressor emissions for Import/Export Terminals by 9% and for Storage Stations by 36%.

B.3.6.4. Centrifugal Compressors (Import/Export and Storage)

Compressor counts were changed, as described in section B.3.6.3. The updated counts were 7 centrifugal compressors at Import/Export Terminals (up from 6.6) and 88 centrifugal compressors at Storage Stations (up from 64). The change in emissions was an increase of 9% and 36%, respectively.

B.3.6.5. Compressor and Engine Exhaust (Import/Export)

The activity factors were changed to reflect the reported LNG throughput at the Import/Export Terminals, as determined by ICF's internal analysis of EIA data. The throughput of 349 Bcf (as reported to EIA), compared to the throughput of 431 Bcf in the EPA Inventory, led to a 19% decrease in the emissions.

B.3.7. Gas Distribution

No changes were made to this segment of the U.S. Inventory.

B.4. Petroleum Inventory

The net change to the Petroleum segment of the U.S. Inventory was an increase of 26% compared to the EPA Inventory value. The biggest categories contributing to this increase were the inclusion of stranded gas venting from oil wells and updated estimates of associated gas flaring estimates. The specific changes are described in the following sections.

B.4.1. Oil Production

B.4.1.1. Oil Tank Venting

This section was not changed.

B.4.1.2. Oil Tank Dump Valve Venting

This source was not included in the published EPA Inventory, but it is included in subpart W of the GHGRP. Therefore, emission and activity factors were developed from the 2011 subpart W data and were included in the 2011 Baseline. The subpart W derived emission factor is 17,000 scf/year/leaking dump valve and the reported number of leaking dump valves to subpart W is 3,044. It was assumed that subpart W covers 85% of the reporters, so the activity factor was increased to 3,581. The dump valve venting methane emissions totaled nearly 0.1 Bcf.

B.4.1.3. Pneumatic Devices

Pneumatic devices in the EPA Inventory were broken out into two categories, low bleed and high bleed, with two emission factors, 52 scf/day (19 Mcf/yr) and 330 scf/day (210 Mcf/yr), respectively. For the 2011 Baseline, pneumatic devices were broken out the same as described in section B.3.1.7. The overall count of devices was kept the same as in the EPA Inventory. The net effect of these changes is an increase in emissions of 8% to over 24 Bcf.

B.4.1.4. Chemical Injection (Pneumatic) Pumps

The count of devices in the published Inventory was compared to the count obtained from subpart W, and was shown to be underestimated (30,600 devices in subpart W vs. 28,000 in the Inventory). Therefore, the updated count from subpart W was used and results in an increase of emissions by about 10%. However, Gas STAR reductions for gas powered pumps were not allocated to the chemical injection pumps in the U.S. Inventory. This was corrected by subtracting a portion of the Gas STAR reductions (determined by a weighted ratio). This resulted in a net decrease in emissions by 30% to just less than 2 Bcf.

B.4.1.5. Oil Well Completions

Oil well completions were not broken out for hydraulically fractured wells and non-hydraulically fractured wells in the published Inventory, and used a single emission factor of 733 scf/completion.

However, these two categories were broken out in subpart W, so this change was made to the 2011 Baseline. The data reported to subpart W was used to develop new emission factors, which were 230,000 scf/completion for hydraulically fractured oil wells and 220 scf/completion for non-hydraulically fractured oil wells.

The activity factors were updated using completions data from the most recent API Quarterly Completions Report. These values are 15,382 hydraulically fractured well completions and 10,684 non-hydraulically fractured well completions for 2011. This compares to the single EPA value of 19,468 well completions. Using the updated completion counts and emission factors, the emissions from hydraulically fractured well completions were 5 Bcf, and emissions from non-hydraulically fractured well completions were less than 0.01 Bcf.

B.4.1.6. Oil Well Workovers

Oil well workovers were not broken out for hydraulically fractured wells and non-hydraulically fractured wells in the published Inventory, and used a single emission factor of 96 scf/workover. However, these two categories were broken out in subpart W, so this change was made to the 2011 Baseline. The data reported to subpart W was used to develop new emission and activity factors. The new emission factors were found to be 440,000 scf/workover for hydraulically fractured oil wells and 310 scf/workover for non-hydraulically fractured oil wells. The activity factors were 143 hydraulically fractured oil well workovers and 40,200 non-hydraulically fractured oil well workovers.

While determining the factors from hydraulically fractured oil wells in subpart W was straightforward, the non-hydraulically fractured oil well analysis was less clear. For non-hydraulically fractured oil wells, emissions from completions and workovers were lumped together, and the only way to separate them out was to use the reported number of “Completion Venting Days” in subpart W. Therefore, only those production sites that reported no completion venting days but still reported emissions were used to determine the factors for oil well workovers without hydraulic fracturing.

The net change to emissions was an increase to 0.04 Bcf.

B.4.1.7. Stranded Gas Venting from Oil Wells

This source was not included in the published EPA Inventory, but it is included in subpart W of the GHGRP. Therefore, emission and activity factors were developed from the 2011 and 2012 subpart W data and were included in the 2011 Baseline. The subpart W derived emission factor is 570,000 scf/yr/venting well, and the reported number of venting wells was 9,722. The Subpart W development estimated that it would cover 85% of the sector, so the activity factor was increased to 11,438. This category accounts for nearly 7 Bcf of emissions.

B.4.1.8. Oil Wellheads

The emission factors in the published Inventory were updated to the emission factors published in subpart W. The well count was also updated to reflect the count in the *World Oil* magazine, as was done with the gas well count. Well types were broken out using an internal data set which broke out well type by basin. This resulted in a net increase in emissions between light crude and heavy crude wellheads of 66%.

B.4.1.9. Separators

The emission factors in the published Inventory were updated to the emission factors published in subpart W. This resulted in a net decrease in emissions between light crude and heavy crude separators of 44%.

B.4.1.10. Heater/Treaters

The emission factor in the published Inventory was updated to the emission factor published in subpart W. This resulted in a decrease in emissions of 43%

B.4.1.11. Headers

The emission factors in the published Inventory were updated to the emission factors published in subpart W. This resulted in a net decrease in emissions between light crude and heavy crude headers of 46%.

B.4.1.12. Well Drilling

The number of oil wells drilled was updated to reflect the number of completions in 2011, as described in section B.4.1.5. Each oil well completion was counted as one well drilled, and this increased the count of wells drilled from 21,899 in the EPA Inventory to 26,066 wells drilled in the 2011 Baseline. This resulted in a net increase in emissions from well drilling by 19% to 0.06 Bcf.

B.4.1.13. Flaring

The EPA bases its flaring estimate on company data reported to states and then to the EIA. In the 2011 Baseline, flaring was based on the values reported by the World Bank's Global Gas Flaring Reduction (GGFR)[43] program. It was assumed that all of the estimated flaring was from associated gas. The GGFR estimated that 7.1 billion cubic meters of gas was flared in the U.S. in 2011. It was then assumed that the flares were 98% efficient, resulting in methane emissions of 5 Bcf. This is a large increase over the value in the published Inventory (0.01 Bcf).

B.4.2. Oil Transportation

No changes were made to this segment of the U.S. Inventory.

B.4.3. Oil Refining

No changes were made to this segment of the U.S. Inventory.

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[43] Available online at http://go.worldbank.org/G2OAW2DKZ0

Appendix C. Emission Projection to 2018

C.1. Summary

The 2018 forecast of U.S. natural gas and petroleum systems methane emissions starts with the 2011 Baseline described in Appendix B. ICF based the emissions forecast on several sources to drive emissions through the time horizon. The primary source was the U.S. EIA's 2014 Annual Energy Outlook (AEO) Early Release. ICF also relied upon EIA's 2013 AEO, the API Quarterly Well Completion Report, and an INGAA Foundation study[44] which forecast requirements for selected infrastructure and equipment for the natural gas and petroleum industry. In addition, expected emission reductions as a result of NSPS subpart OOOO were incorporated into the forecast. The result is an estimated 9.5 million metric tonnes (491 Bcf) of methane emitted from all sectors of the oil and gas industry in 2018 before application of NSPS reductions, an increase of 12%. Inclusion of NSPS reductions reduces the emissions to 9.0 million metric tonnes (466 Bcf), an increase of 4.5% from 2011, with all of the net increase coming from the oil sector.

C.2. Natural Gas Inventory Activity Factors

C.2.1. EIA 2014 Annual Energy Outlook Early Release

ICF used EIA's 2014 AEO Early Release "Lower 48 Natural Gas Production and Supply Prices by Supply Region" forecast out to 2018, broken out into the eight AEO regions as shown in Figure 1, to drive the growth for several of the sources in the natural gas sector. The "Lower 48 Natural Gas Production and Supply Prices by Supply Region" forecasts natural gas production, which was ultimately used as the driver for each region for future emissions in 2018, per Equation 1.

$$AF_{region-2011} \times \frac{GasP_{region-2018}}{GasP_{region-2011}} = AF_{region-2018} \qquad \textit{Equation 1}$$

Where:

$AF_{region-2011}$ = regional activity factor for the 2011 inventory
$GasP_{region-2018}$ = regional gas production projected in EIA's 2014 AEO for 2018
$GasP_{region-2011}$ = regional gas production in EIA's 2014 AEO for 2011
$AF_{region-2018}$ = regional activity factor for 2018 inventory projection

The activity factors for the following sources were driven using this method:

[44] *North American Midstream Infrastructure Through 2035 – A Secure Energy Future, Prepared for the INGAA Foundation*, ICF International, 2011.

- Gas Production and Gathering and Boosting
  - Dehydrators
  - Kimray pumps
  - Condensate tanks
  - Compressor exhaust
- Gas Processing
  - AGRs
  - Dehydrators
  - Kimray pumps
- Gas Storage
  - Pneumatics

Map of EIA Regions

Source: EIA AEO 2013

C.2.2. EIA 2013 Annual Energy Outlook

ICF used the EIA's 2013 Annual Energy Outlook in addition to the 2014 Early Release for "Natural Gas Consumption by End-Use Sector and Census Division" since this data was not part of the 2014 Early

Release. The Residential and Commercial gas consumption forecast was used from this data set as the driver for many activity factors, per Equation 2.

$$AF_{region-2011} \times \frac{GasC_{region-2018}}{GasC_{region-2011}} = AF_{region-2018} \qquad \textit{Equation 2}$$

Where:

$AF_{region-2011}$ = regional activity factor for the 2011 inventory
$GasC_{region-2018}$ = regional gas consumption projected in EIA's 2013 AEO for 2018
$GasC_{region-2011}$ = regional gas consumption in EIA's 2013 AEO for 2011
$AF_{region-2018}$ = regional activity factor for 2018 inventory projection

The activity factors driven by this forecast include all of the activity factors in Gas Distribution and Gas Storage, except for those listed in section C.2.1. In the Gas Storage segment, it was assumed that even if the gas consumption dropped in a region that the number of storage stations and associated equipment did not drop. Further, Cast Iron Mains and Unprotected Steel Mains and Services in the Gas Distribution segment were not driven by this forecast, as no further cast iron or unprotected steel equipment is being installed in the U.S. Instead, it was assumed that 3% of the remaining cast iron and unprotected steel equipment is replaced with protected steel and plastic equipment, respectively, each year based on historical replacement reported to PHMSA.

C.2.3. API's Quarterly Well Completions Report

ICF used API's Quarterly Well Completions Report as the source to drive a majority of the emission sources in the Gas Production segment. The analysis assumed that well completions will continue through 2018 at the 2012 rate and used this summation of new well completions to drive well-related activity factors. In addition to new well completion, shut-in and abandoned wells were also accounted for in the well count forecast. To estimate the number of wells shut-in per year, ICF compared the growth rate of gas wells to the growth of gas production in each region. A shut-in percentage, between 0.1% and 5%, was then assigned to each region in order to align the well count growth with the gas production growth in that region. The regional percentages are listed below.

Gas Well Retirement Rate

Region	Gas Well Retirement Rate
Northeast	0.1%
Gulf Coast	1.0%
Midcontinent	2.0%
Southwest	2.0%
Rocky Mountain	1.0%

Region	Gas Well Retirement Rate
West Coast	3.0%
Alaska	5.0%

Once the updated well counts were set for each region, a ratio of wells in 2018 to wells in 2011 was used to drive the activity for most the emissions sources in the Gas Production segment. In addition to using the ratio of wells, several emission sources in the Gas Production segment had their own activity factor drivers from the EPA Inventory. These activity factor drivers were multiplied by the 2018 well counts to obtain new activity levels for 2018. These sources and their activity factor drivers are listed below for each of the regions in the Inventory.

Activity Factory Drivers for Select Sources by Region

Source	NE	GC	MC	SW	RM	WC	AK	Units
Heaters	0.41	0.22	0.41	0.27	0.46	1.0	1.0	Per well
Separators	0.71	0.66	0.44	0.56	0.50	0.73	0.73	Per well
Dehydrators	0.14	0.14	0.14	0.14	0.14	0.14	0.14	Per well
Meters/Piping – Gas wells	1.15	1.15	1.15	1.15	1.15	1.15	1.15	Per well
Meters/Piping – Associated Wells	0.05	0.05	0.05	0.05	0.05	0.05	0.05	Per assoc. well
High Bleed Pneumatic Devices	0.05	0.07	0.16	0.13	0.15	0.10	0.10	Per well
Intermittent Bleed Pneumatic Devices	0.06	0.09	0.19	0.17	0.18	0.13	0.13	Per well
Intermittent Bleed Pneumatic Devices – Dump Valves	0.18	0.26	0.58	0.50	0.55	0.38	0.38	Per well
Low Bleed Pneumatic Devices	0.19	0.28	0.62	0.53	0.59	0.40	0.40	Per well
Chemical Injection Pumps	0.14	0.03	0.14	0.06	0.18	0.68	0.68	Per well
Mishaps	0.25	0.25	0.25	0.25	0.25	0.25	0.25	Per mile of pipeline

†- Activity factor drivers also account for pneumatics from Gathering and Boosting Stations.

The only exceptions to the two methodologies described above for the Gas Production segment include the gas well completion values for 2018, which used the 2012 gas well completion values directly from the API Quarterly Well Completions Report, and the high bleed pneumatics. High bleed pneumatics are phased out in most segments due to NSPS subpart OOOO regulations but the forecast assumes that no new high bleed pneumatics are installed in any segment.

C.2.4. INGAA Foundation Midstream Study[45]

ICF used the INGAA Foundation study for the Gathering and Boosting and Gas Processing segments. The INGAA study provided yearly forecast of incremental gathering pipeline miles, gas processing plants, and processing compressor count, which was combined with the existing activity data from 2011, per Equation 3.

$$AF_{region-2011} + IF_{region-2018} = AF_{region-\,2018} \qquad \textit{Equation 3}$$

Where:

$AF_{region-2011}$ = regional activity factor for the 2011 Inventory
$IF_{region-2018}$ =regional, cumulative INGAA forecast of equipment counts out to 2018
$AF_{region-2018}$ = regional activity factor for 2018 inventory projection

For the Gathering and Boosting segment, the activity factors all of the emission sources were then driven off of a ratio of pipeline miles in 2018 to pipeline miles in 2011 to obtain the 2018 activity levels, except for those sources listed in section C.2.1.

For the Gas Processing segment, pneumatic devices and blowdowns/venting were driven directly off of the gas processing plant count. The other sources were all driven off of a ratio between the compressor count in 2018 and the compressor count in 2011, except for those sources listed in section C.2.1.

C.2.5. Gas Transmission

Growth for the Gas Transmission segment was not driven off of a forecast, but rather off of an analysis of past pipeline infrastructure changes. The EPA Inventory contains data on the length of transmission pipeline miles back to 1990. The data from 1990 to 2011 was analyzed to develop a pipeline expansion trend. This incremental value was then used to drive the pipeline miles forward to 2018. All of the other sources, except those listed in section C.2.1, were then driven off of a ratio of pipeline miles in 2018 to the pipeline miles in 2011.

C.2.6. LNG

LNG Import/Export terminals were forecasted off of FERC data and an internal analysis of potential import/export terminals. From this analysis, it is assumed that one new export terminal will come online on the Gulf Coast by 2018. (Several other facilities will be converted from import to export terminals.)

[45] *North American Midstream Infrastructure Through 2035 – A Secure Energy Future, Prepared for the INGAA Foundation*, ICF International, 2011.

All of the other emission sources are either driven off of ratios between the 2018 and 2011 terminal counts or EPA activity drivers, as described in sections B.3.6.2, B.3.6.3, B.3.6.4, and B.3.6.5.

C.3. Petroleum Inventory Activity Factors

C.3.1. EIA 2014 Annual Energy Outlook Early Release

ICF used EIA's 2014 AEO Early Release "Petroleum and Other Liquids Supply and Disposition" and "Lower 48 Crude Oil Production and Wellhead Prices by Supply Region" forecasts out to 2018, broken out into the same eight AEO regions as shown above for natural gas, to drive the activity for many of the sources in the petroleum sector. These analyses both forecast petroleum production, which was ultimately used as the activity driver for each region for emissions in 2018, per Equation 4.

$$AF_{region-2011} \times \frac{OilP_{region-2018}}{OilP_{region-2011}} = AF_{region-2018} \qquad \textit{Equation 4}$$

Where:

$AF_{region-2011}$ = regional activity factor for the 2011 inventory
$OilP_{region-2018}$ = regional oil production projected in EIA's 2014 AEO for 2018
$OilP_{region-2011}$ = regional oil production in EIA's 2014 AEO for 2011
$AF_{region-2018}$ = regional activity factor for 2018 inventory projection

All of the emission sources in the Oil Transportation and the Oil Refining segments were driven using the AEO 2014 Early Release "Petroleum and Other Liquids Supply and Disposition" forecast. Most of the sources in the Oil Production segment were driven by the API Quarterly Well Completions Report, as detailed in section C.3.2, but several source were driven by the "Petroleum and Other Liquids Supply and Disposition" forecast. These sources include oil tanks, oil tank dump valve venting, floating roof tanks, sales areas, and flares. Also, the offshore activity factors were driven by the AEO 2014 Early Release.

C.3.2. API's Quarterly Well Completions Report

The approach used to estimate oil well counts was the same as that used for gas well counts, based on continued well completions at the current rate through 2018. ICF used API's Quarterly Well Completions Report as the source to drive a majority of the emission sources in the Oil Production segment. The completions data was used to determine how many active wells would be in operation in 2018, which was then used to drive the emission sources in Oil Production.

The 2012 count of completions was assumed to be constant each year through 2018. However, some wells are shut-in and abandoned each year, so this was accounted for well count forecast. To determine the number of wells shut-in per year, ICF compared the growth rate of wells to the growth of oil production in each region. A shut-in percentage, between 0.1% and 5%, was then assigned to each region in order to align the well count growth with the oil production growth. The percentages used in each region are listed below.

Annual Oil Well Retirement Rate by Region

Region	Oil Well Retirement Rate
Northeast	4.0%
Gulf Coast	0.1%
Midcontinent	0.5%
Southwest	5.0%
Rocky Mountain	2.0%
West Coast	2.5%
Alaska	5.0%

Once the updated well counts were set for each region, a ratio of wells in 2018 to wells in 2011 was used to drive the activity for all the emissions sources in the Oil Production segment, except those listed in section C.3.1. The only exceptions to this were the oil well completion values which used the 2012 oil well completion values directly from the API Quarterly Well Completions Report. Also, it is assumed that no new high bleed pneumatics are installed.

C.4. Natural Gas and Petroleum Inventory Emission Factors

For nearly every source category, ICF used the same emission factors for each emissions source as those used in development of the 2011 inventory. The exceptions are listed out individually below.

C.4.1. Sources with Different Emission Factors

The following emission sources (with their respective industry segments) had different emission factors between 2011 and 2018.

- Heaters (Gas Production)
- Separators (Gas Production)
- Dehydrators (Gas Production)
- Meters/Piping (Gas Production)
- Pneumatics (Gas Processing)

The four emission sources in the Gas Production segment used different emission factors between 2011 and 2018 in only two of the regions, the Northeast and Midcontinent. This is because the 2011 baseline year uses the same emission factors that the EPA Inventory uses, which come from the 1996 GRI study and are divided into Eastern and Western regions. In 2011, the Northeast and Midcontinent regions use the Eastern emission factors, which are substantially lower than the Western emission factors. The Eastern emission factors describe equipment associated with older, lower producing gas wells that existing in most of the Northeast and Midcontinent when the GRI study was undertaken in 1992. However, most of the new wells in these regions are much higher producing wells, better characterized by the Western emission factors from the 1996 GRI study. Therefore, the incremental increases in equipment counts associated with these wells (the four sources listed above) have the Western emission factors applied to them, while the older equipment already in place in 2011 have the lower Eastern emission factors applied to them.

For pneumatics in Gas Processing, all new pneumatic devices must be zero bleed devices, per NSPS subpart OOOO. Therefore, the incremental increase in pneumatic devices in 2018 use an emission factor of zero emissions, assuming that all the devices are zero bleed.

C.5. Emission Reductions – NSPS subpart OOOO

The new 2018 forecast of emissions was then modified to reflect the expected emission reductions as a result of NSPS subpart OOOO. Per the NSPS, the following sources would see emissions reductions as a result of regulation:

- Gas Well Completions with Hydraulic Fracturing
- Gas Well Workovers with Hydraulic Fracturing
- Pneumatic Devices
- Reciprocating Compressors (excluding Production and Transmission sectors)
- Centrifugal Compressors (excluding Production and Transmission sectors)
- Storage Tanks
- Dehydrators

The total emissions from these sources, including reductions resulting from regulation controls, were calculated per Equation 6.

$$(AF_{region-2018} \times EF_{2011}) - \left(AF_{region-2018} + AF_{region-2011}(TO-1)\right) \times EF_{2011} \times PC \times R = E_{2018}$$

Equation 6

Where:

AF$_{\mathbf{region-2018}}$ = regional activity factor for the 2018 inventory
EF$_{\mathbf{2011}}$ = emission factor used in the 2011 inventory
AF$_{\mathbf{region-2011}}$ = regional activity factor for the 2011 inventory
TO = turnover rate (assumed to be 1% for pneumatics in all sectors and 1% for reciprocating and centrifugal compressors in gathering/boosting and processing)

PC = population coverage, estimated from NSPS Background Technical Support Document[46]
R = reduction percent, estimated from NSPS Background Technical Support Document**Error! Bookmark not defined.**

E_{2018} = estimate of emissions from the respective source category in 2018

[46] New Source Performance Standards Background Technical Support Documents, available at: http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf and http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf

Appendix D. Methane Mitigation Technologies

This section provides additional information on some of the available methane mitigation technologies. Most of the performance data are as reported to the EPA Gas STAR program and may have been modified for the analysis in this study.

D.1. Installing Plunger Lift Systems in Gas Wells

Plunger lift systems are cost-effective methods for removing the buildup of liquids inside a gas well. Plunger lift systems increase production by maintaining gas flow while significantly reducing methane emissions that would have otherwise occurred with well blowdown operations. A plunger lift removes accumulated fluids by using the downhole gas pressure to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial options.

D.1.1. Technology Background

Liquid loading of the wellbore can impede and sometimes halt gas production. Gas flow through the well is often maintained by removing accumulated fluids through venting the well to atmospheric pressure, also known as “blowing down” the well. Installing a plunger lift system removes the accumulated liquids with the added benefits of increasing production and recovering gas that would otherwise be emitted through a well blowdown.

Environmental Effectiveness and Key Factors: Installing Plunger Lift Systems

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	100% (assuming the gas lifting the plunger is recovered to a sales line)	100% (assuming the gas lifting the plunger is recovered to a sales line)	0%
Factors affecting efficiency	Depth and pressure of the well	Depth and pressure of the well	
Limits of technical feasibility	Each plunger lift system is subject to a minimum requirement for each well application. The minimum gas flow is 400 standard cubic feet (scf) per barrel (bbl) of fluid per 1,000 feet of well depth. Additionally, wells must have a shut-in wellhead pressure that is 1.5 times the sales line pressure. The potential amount of methane available for recovery will increase as the pressure and the venting frequency increase.		

Plunger lift systems rely on the natural buildup of gas pressure, as the gas well becomes shut-in from liquid accumulation to lift a plunger remove the accumulated liquids. To recover the gas, the sales line pressure must be connected to the wellhead and the pressure must be less than the downhole pressure of the well. This enables gas to flow into the sales line, preventing emissions and continuing well production.

Cost Benefit Analysis: Installing Plunger Lift Systems[47]

CapEx per well and per unit production (2013 USD):	$2,400 to $9,600 per plunger lift system
OpEx per well and per unit production (2013 USD):	$860 to $1,600 per year – Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months.
Revenue per well and per unit production:	$18,800 to $73,000 per year (at $4.00 per Mcf of gas)
Payback Period:	1 to 7 months (at $4.00/Mcf of gas)

D.1.2. Technology Penetration

Plunger lifts are a fully developed and widespread technology for gas wells with vertical orientation, and are more often viewed as production enhancers than as a methane mitigation technology. One service provider was quoted by the EPA that in 2008 there were about 150,000[48] plunger lifts in service, approximately 30 percent of gas wells at the time. In 2012, API/ANGA released a study showing that 36 percent of their survey well population had operational plunger lifts.[49]

Plunger lifts, however, are still being adapted for use in gas wells with a deviated orientation such as horizontal wells. Few studies have been done on the use of plunger lifts on horizontal wells. Therefore, more research must be done to determine the penetration of plunger lifts on horizontal wells and effectiveness of plunger lifts installed on horizontal wells.

D.2. Replacing Wet Seals with Dry Seals in Centrifugal Compressors

Centrifugal compressors are used in the production sector to pressurize gas in pipelines to transport gas downstream. Wet seal centrifugal compressors are a large source of emissions, as a result of their wet seal degassing operations. Seal oil (wet seals) on the rotating shafts of centrifugal compressors prevent the high-pressure natural gas from escaping the compressor casing. These wet seals act as a barrier to the high pressure natural gas. Natural gas however, becomes entrained in the seal oil, which leads to emissions as the seal oil degasses to the atmosphere. By converting to dry seals, which use high pressure

[47] Plunger Lift System Economics extracted from U.S. EPA Lessons Learned: Installing Plunger Lift Systems in Gas Wells http://epa.gov/gasstar/documents/ll_plungerlift.pdf

[48] Robinson, D. (2012) *Liquids Unloading options for Natural Gas Wells.* 2012 Natural Gas STAR Annual Implementation Workshop. April 12, 2012: Denver, Colorado. http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/robinson.pdf

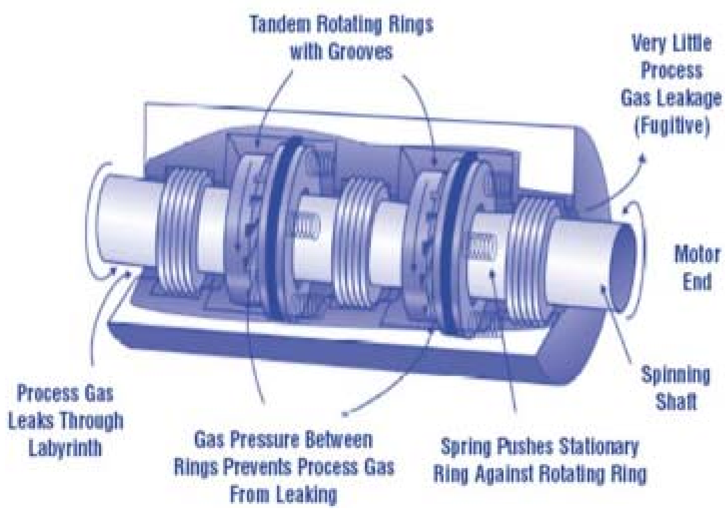
[49] API (2012) *API/ANGA Information on Gas Well Liquids Unloading*. EPA Stakeholder Workshop September 13-14, 2012: Washington D.C. http://www.epa.gov/climatechange/Downloads/ghgemissions/2012Workshop/Smith_BP.pdf

gas seals instead of oil, lower emissions are achieved while reducing power requirements and improving compressor performance and reliability.

D.2.1. Technology Background

Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. Typically, compressors have two seals, one on each end of the compressor. Wet seals use oil, which is circulated under high pressure three rings around the compressor shaft, which creates a barrier against the compressed gas escaping. This oil barrier prevents gas from escaping, however a significant amount of gas is absorbed by the oil under the higher pressures of the compressor. Since this affects the integrity of the seal oil, it must be degassed through the use of process equipment and recirculated. The recovered methane is commonly vented to the atmosphere.

Dry seals on centrifugal compressor



Environmental Effectiveness and Key Factors: Replacing Wet Seals with Dry Seals on Centrifugal Compressors

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	97%	97%	0%
Factors affecting efficiency	See below	See below	
Limits of technical feasibility	The compressor pressure must be below 3,000 psi and the temperature must be below 300^{o} F. Furthermore; compressors should not be towards the end of their life.		

To prevent the absorption of gas into the seals, dry seals can be installed which operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Dry seals create a barrier, forcing the gas to leak down the shaft where it has a small chance of leaving the compressor between the rotating and stationary rings. Dry seals substantially reduce methane emissions, operating costs, and enhance compressor efficiency.

Cost Benefit Analysis: Replacing Wet Seals with Dry Seals on Centrifugal Compressors[50]

CapEx per well and per unit production (2013 USD):	$400,000 (Seals + Engineering Installation)
OpEx per well and per unit production (2013 USD):	$17,500
Revenue per well and per unit production:	$180,500 per year (at $4.00/Mcf of gas)
Payback Period:	29 months (at $4.00/Mcf of gas)

D.2.2. Technology Penetration

Over the past decade, dry seals have become favored over wet seal compressors because they do not require a separate seal oil circulation and regeneration system. For offshore platforms this is ideal due to space limitations and for gathering and boosting operations it results in less operational and maintenance costs. One vendor was quoted that almost 90 percent of new centrifugal compressors sold are equipped with dry seals. Dry seal retrofits are not as common due to the high upfront costs and downtime losses incurred. Wet Seal Degassing Recovery System for Centrifugal Compressors

D.3. Wet Seal Degassing Recovery System for Centrifugal Compressors

Centrifugal compressors are widely used in the production of natural gas. Seals on the rotating shafts of centrifugal compressors prevent the high-pressure natural gas from escaping the compressor casing. Wet seals use high-pressure oil (wet seals) as a barrier against escaping gas. To prevent emissions from these centrifugal compressors, one can capture the seal oil degassing stream from a small disengagement vessel and recycle it back into the compressor suction, or as high pressure turbine fuel gas, or low pressure fuel gas to heaters.

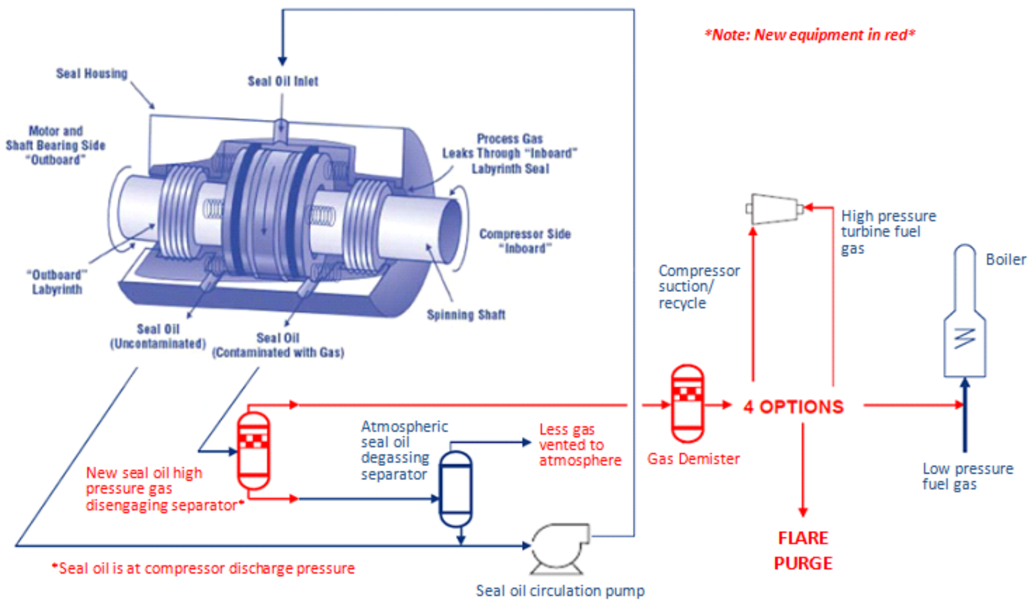
D.3.1. Technology Background

Centrifugal compressor wet seal degassing recovery systems have been demonstrated installed as a cost-effective alternative to dry seals for new compressors. They use commercially available equipment and projected to be much less expensive than replacing wet seal systems with dry seals but have not been commercially demonstrated for retrofit applications.

[50] Economics extracted from U.S. EPA Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors http://epa.gov/gasstar/documents/ll_wetseals.pdf

There are multiple options for the degassing stream recovered through this system including: the gas can be sent as low pressure fuel to a boiler, high pressure fuel to a turbine, recycled back to the compressor suction, or sent to a flare. All four options significantly reduce methane emissions from seal oil degassing operations.

Wet seal degassing recovery system for centrifugal compressors - Source: U.S. EPA



Environmental Effectiveness and Key Factors: Wet Seal Recovery System for Centrifugal Compressors

Environmental Effectiveness	**CO_2**	**CH_4**	**N_2O**
Typical abatement efficiency for key GHGs (primary abatement metrics), %	Up to 100% (Assuming recovered gas is not flared)	Up to 99%	N/A
Factors affecting efficiency	Depending on the use of the recovered degassing emissions.	Depending on the use of the recovered degassing emissions.	
Limits of technical feasibility	"Knock-out" vessels to recover any seal oil mist from the recovered gas, if the gas is to be used as fuel. Piping capacity must exist to use recovered degassing emissions.		

Cost Benefit Analysis: Wet Seal Recovery System for Centrifugal Compressors

CapEx per One Centrifugal Compressor (2013 USD):	$33,700 (Cost for seal oil gas separator, seal oil gas demister for low quality gas, and seal oil gas demister for high quality gas)
OpEx per One Centrifugal Compressor (2013 USD):	Minimal
Revenue per One Centrifugal Compressor :	$120,000 (at $4.00/Mcf of gas)
Payback Period:	3 months (at $4.00/Mcf of gas)

D.3.2. Technology Penetration

Wet seal degassing recovery systems are feasible but are not currently not available as an off-the-shelf technology. This technology has only been documented as part of an Original Equipment Manufacturer design, meaning the wet seal degassing recovery system was installed with the centrifugal compressor station.[51] There is no documentation to date reporting the implementation of this technology as a retrofit to an existing centrifugal compressor. Operators will likely need to work with the original compressor manufacturer to have this technology installed.

D.4. Installing Vapor Recovery Units on Storage Tanks

Crude oil storage tanks are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. The crude oil experiences a drop in pressure as it is transferred to the crude oil storage tank. Due to this drop in pressure, light hydrocarbons vaporize or “flash out” and collect in the space between the liquid and the fixed roof of the tank. The vapors are vented to the atmosphere to avoid pressure build-up. Vapor Recovery Units (VRUs) are installed on crude oil storage tanks to prevent these vented emissions.

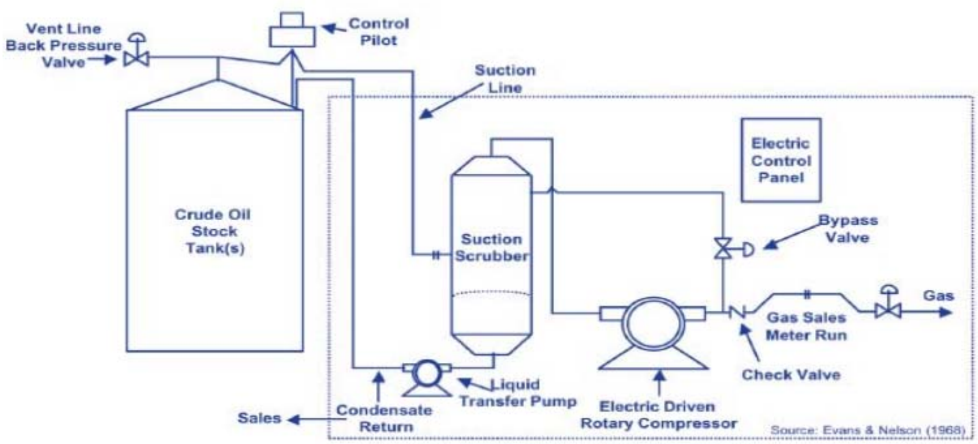
D.4.1. Technology Background

Underground crude oil contains many dissolved light hydrocarbons. These hydrocarbons typically flash out during production as well as through a series of separators. Once it has gone through separators, the crude oil is pumped into a storage tank to await sale and transportation off site; the remaining light hydrocarbons flash out of the crude, into the vapor space of the tank. The same principles apply for condensate. These resulting vapors are typically vented or flared. The composition of these vapors varies, but typically include methane, propane, butane, and ethane as well as VOCs and HAPs.

[51] Smith, R. (2012) *Centrifugal Compressor Wet Seals Seal Oil Degassing & Control*. Natural Gas STAR Annual Workshop; Denver, CO. http://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/smith.pdf

VRUs are installed to recover these vapors to prevent emissions and reduce flaring. VRUs use a compressor and a suction line, to pull the vapors into a scrubber tank, where the recovered hydrocarbons can then be transported to multiple places, including the sales line.

VRU process schematic - Source: Evans & Nelson (1968)



Environmental Effectiveness and Key Factors: Installing VRUs on Storage Tanks

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	95%	95%	0%
Factors affecting efficiency	The reliability of the suction scrubber and compressor	The reliability of the suction scrubber and compressor	Assuming the storage tank vented emissions were not previously flared.
Limits of technical feasibility	VRUs capture approximately 95% of flashing losses, from storage tanks. VRUs success depends on the lines connecting the tanks to the compressor, as well as the compressor which creates the suction.		

Cost Benefit Analysis: Installing VRUs on Storage Tanks[52]

CapEx per well and per unit production (2013 USD):	$44,500 to $129,000
OpEx per well and per unit production (2013 USD):	$9,100 to $20,800
Revenue per well and per unit production:	$20,000 to $380,000 per year (at $4.00/Mcf of gas)
Payback Period:	4 to 51 months (at $4.00/Mcf of gas)

D.4.2. Technology Penetration

VRUs are a widely adopted methane mitigation technology. There are several service providers that implement VRUs across the United States including HY-BON, Exterran, and COMM Engineering.

D.5. Converting High-Bleed Pneumatic Devices to Low-Bleed

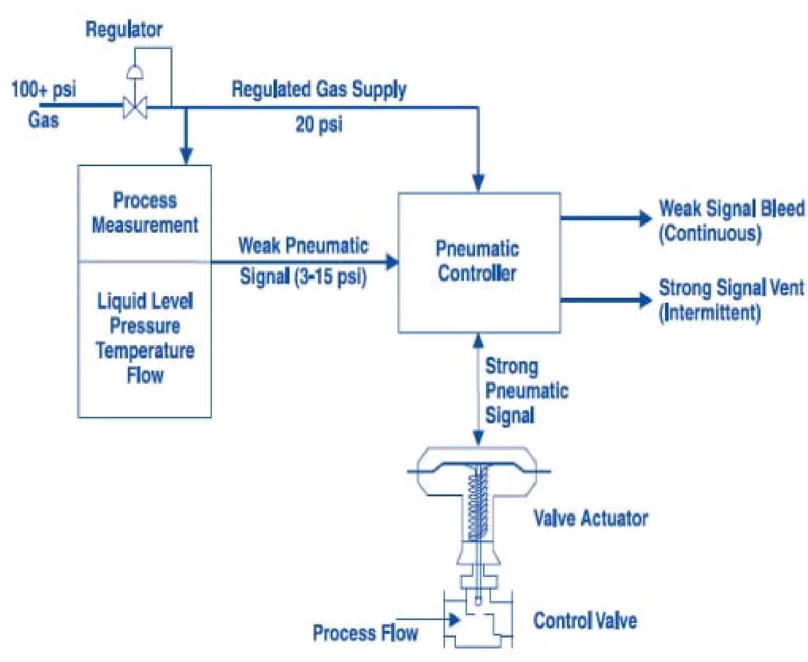
Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Pneumatic devices vent natural gas as a part of normal operations and are one of the biggest sources of emissions in the production sector. Older pneumatic devices can have a relatively high bleed rate and emissions can be significantly reduced by converting the devices to low-bleed models.

D.5.1. Technology Background

The volume of natural gas vented from pneumatic devices varies by model and age. High-bleed pneumatic devices vent over six standard cubic feet of CH_4 per hour per device. The average high-bleed pneumatic device vents 330 standard cubic feet CH_4 per day per device. Low-bleed pneumatic devices vent six or less standard cubic feet of CH4 per hour per device. Low-bleed pneumatic devices vent on average to 52 cubic feet CH_4 per day per device. By retrofitting or switching high-bleed pneumatic devices to low-bleed pneumatic devices, emissions are reduced. Not all pneumatic device applications are appropriate for low-bleed devices, but field experience has shown that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted.

[52] Economics extracted from U.S. EPA Lessons Learned: Installing Vapor Recovery Units on Storage Tanks http://epa.gov/gasstar/documents/ll_final_vap.pdf

Pneumatic device schematic - Source: U.S. EPA Lessons Learned



Environmental Effectiveness and Key Factors: Converting High-Bleed Pneumatics to Low-Bleed

Environmental Effectiveness	**CO_2**	**CH_4**	**N_2O**
Typical abatement efficiency for key GHGs (primary abatement metrics), %	N/A	84%	N/A
Factors affecting efficiency		See below.	
Limits of technical feasibility	Methane abatement efficiency is dependent upon the initial bleed rate of the high-bleed rate device. Bleed rates will vary with pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment.		

Cost Benefit Analysis: Converting High-Bleed Pneumatics to Low-Bleed[53]

CapEx per well and per unit production (2013 USD):	\$260 to \$420 (Change to low-bleed at end of life) \$2,300 (Early replacement of high-bleed unit) \$840 (Retrofit)
OpEx per well and per unit production (2013 USD):	N/A
Revenue per well and per unit production:	\$200 to 800 (Change to low-bleed device at end of life) \$1,040 (Early replacement of high-bleed unit) \$920 (Retrofit) (All at \$4.00/Mcf of gas)
Payback Period:	4 to 25 months (Change to low-bleed at end of life at \$4.00/Mcf of gas) 27 months (Early replacement of high-bleed unit at \$4.00/Mcf of gas) 11 months (Retrofit at \$4.00/Mcf of gas)

D.5.2. Technology Penetration

Low bleed pneumatic devices are a mature technology that has been commercially available since the 1990s. Low bleed devices are routinely used for new systems and replacements. Directed replacement for emission reductions are less common.

D.6. Reciprocating Compressor Rod Packing Replacement

Rod packing is the seal that prevents gas from leaking around the displacement rod in a reciprocating compressor – similar in concept to the piston rings in a car engine. Emissions from packing are dependent upon the compressor cylinder pressure, the fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft rod. By developing a timely schedule for the replacement of rod packing systems in reciprocating compressors, one can significantly reduce methane emissions and increase savings.

D.6.1. Technology Background

Rod packing replacement entails replacing a set of flexible rings that fit around the shaft, which creates a seal against high pressure gas leakage. The packing rings are lubricated with circulating oil to reduce wear, however over time these packing rings lead to more gas leaking.

By organizing company-specific financial goals, companies can determine an emission threshold at which it is cost-effective to replace rings and rods. Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 standard cubic feet/hour. Higher leak rates are a consequence of fit, alignment of the packing parts, and wear. Leaking gases are vented to the atmosphere.

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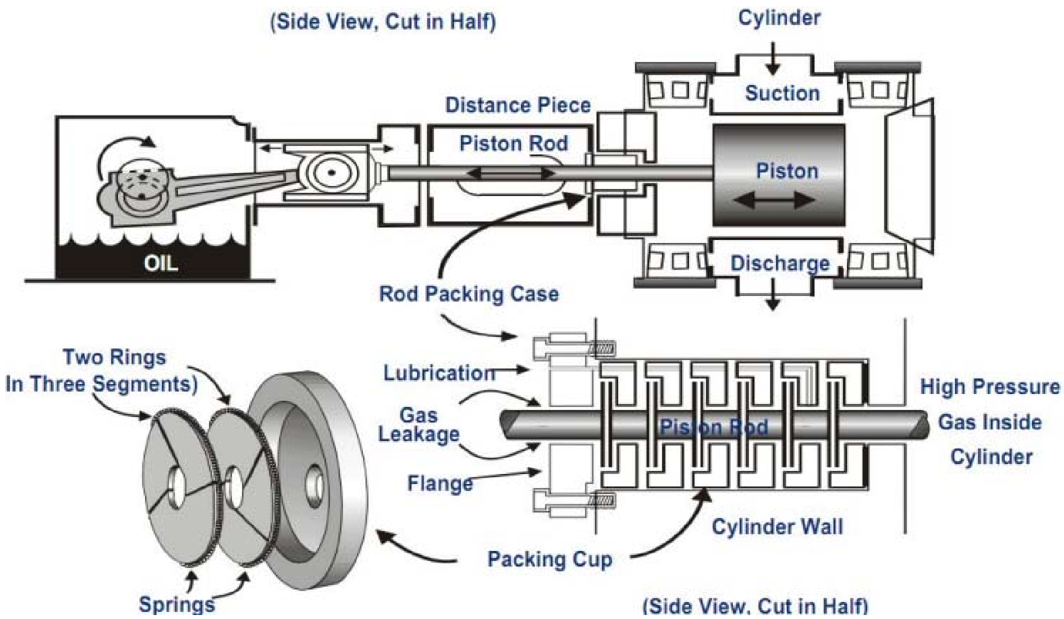
[53] Economics extracted from U.S. EPA Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. http://epa.gov/gasstar/documents/ll_pneumatics.pdf

Reciprocating compressor and rod packing components – Source: U.S. EPA Lessons Learned



Environmental Effectiveness and Key Factors: Reciprocating Compressor Rod Packing Replacement

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	N/A	Up to 98%	N/A
Factors affecting efficiency		See Below.	
Limits of technical feasibility	The timing of replacement will affect abatement efficiency.		

Cost Benefit Analysis: Reciprocating Compressor Rod Packing Replacement[54]

CapEx per well and per unit production (2013 USD):	$2,000 every three years, or $670 per year
OpEx per well and per unit production (2013 USD):	N/A
Revenue per well and per unit production:	$3,500 (at $4.00/Mcf of gas)
Payback Period:	7 months (at $4.00/ Mcf of gas)

[54] Economics extracted from U.S. EPA Lessons Learned: Reducing Methane Emissions From Compressor Rod Packing Systems. http://epa.gov/gasstar/documents/ll_rodpack.pdf

D.6.2. Technology Penetration

Reciprocating rod packing is a general maintenance practice that is commonly performed on reciprocating compressors as they age. Rod packing replacement as a mitigation technology however is a work practice that involves proactively monitoring the rod packing leak rate and replacing the rod packing when it is economic to do so.

D.7. Convert Natural Gas-Driven Chemical Pumps (Kimray Pumps)

Chemical pumps are used for a variety of purposes at a well-site. If there is no source of electricity nearby, operators drive their pumps using the mechanical energy of the natural gas from their well(s). Natural gas driven pumps however vent the natural gas used to drive them. Venting of methane as well as VOCs and HAPs from pneumatic pumps is eliminated by converting the pumps from being natural gas driven to either instrument air-driven or electric.

D.7.1. Technology Background

The most common application of natural gas driven pumps at well sites is for chemical injection and to circulate the glycol in a dehydrator. Instrument air pumps require that the operator install an air compressor, which also requires electricity, to pressurize air to drive the pumps. Electric pumps may either require installing a generator or solar panels or evaluating if a connection to the grid is feasible.

Solar-charged glycol pump (Source: BP)

Environmental Effectiveness and Key Factors: Convert Natural Gas-Driven Chemical Pumps

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	100%	100%	N/A
Factors affecting efficiency	See Below.	See Below.	
Limits of technical feasibility	Dependent on if the air-compressor or electric driven generator is powered by hydrocarbons, Electrical requirements for air compressor, as well as capacity to install piping between air compressor and the glycol circulation pump. Weather can also affect the reliability of solar powered electric-driven pumps.		

Cost Benefit Analysis: Convert Natural Gas-Driven Chemical Pumps[55]

CapEx per well and per unit production (2013 USD):	\$1,200 to \$12,000
OpEx per well and per unit production (2013 USD):	\$120 to \$1,200 (Electricity costs)
Revenue per well and per unit production:	\$10,000 (at \$4.00/Mcf of gas)
Payback Period:	1 to 16 months (at \$4.00/Mcf of gas)

D.7.2. Technology Penetration

Electric pumps and energy exchange pumps (for glycol dehydrators) are common technologies. Many companies have reported replaced pneumatic pumps with electric pumps through the Natural Gas STAR Program.

D.8. Conducting Leak Detection and Repair Programs

Leak Detection and Repair (LDAR) programs are implemented to identify and repair leaking components where it is cost-effective. Through specialized infrared (IR) cameras and a trained team, hydrocarbon emissions can be detected at a production facility.

D.8.1. Technology Background

Unintentional equipment leaks may arise due to normal wear and tear, improper or incomplete assembly of components, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and/or annual temperature change cycles. LDAR programs concentrate on components that are prone to leak enough methane to make repair cost-effective. A

[55] Economics extracted from U.S. EPA PRO Fact Sheet No. 202: Convert Natural Gas-Driven Chemical Pumps http://epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf

specially trained team using an infrared (IR) camera can search for hydrocarbon emissions throughout a facility. After identifying the leaking equipment, repairs are made in cases where the leak poses a safety threat or when the repairs are economically feasible (i.e. benefits outweigh the costs).

IR camera in use for DI&M - Source: Leak Surveys, Inc.

Environmental Effectiveness and Key Factors: Conduction Directed Inspection and Maintenance

Environmental Effectiveness	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	Up to 100% (Assuming leak is repaired)	Up to 100% (Assuming leak is repaired)	N/A
Factors affecting efficiency	See below.	See Below.	
Limits of technical feasibility	The effectiveness of the program will vary by site and company. The effectiveness will vary depending on the number of leaks found and repaired. Reliability depends on the thoroughness and completeness of program, as well as the quality of leak repairs.		

Cost Benefit Analysis: Conducting LDAR[56]

CapEx per well and per unit production (2013 USD):	$124,000 (IR Camera)
OpEx per well and per unit production (2013 USD):	$10 - $6,900 (Depending on repair cost)
Revenue per well and per unit production:	$1,500 (at $4.00/Mcf of gas)
Payback Period:	Dependent on repair cost

D.8.2. Technology Penetration

The technology to perform this methane mitigation practice is common and widely available. Facilities employ technologies such as infrared cameras or handheld leak detection equipment.

[56] Economics extracted from U.S. EPA Lessons Learned: Conduct DI&M at Remote Sites (http://epa.gov/gasstar/documents/conductdimatremotefacilities.pdf)