Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems

May 2016

Prepared for
ONE Future Inc.

Prepared by
ICF International
9300 Lee Highway
Fairfax, VA 22031

Contents

Figures

Tables

Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AR4	UNFCCC Fourth Assessment Report
Bcf	Billion Cubic Feet
CapEx	Capital Expenditures
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GWP	Global Warming Potential
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
$MMTCO_2e$	Million Metric Tonnes CO_2 equivalent
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
VRU	Vapor Recovery Unit

1. Executive Summary

Our Nation's Energy Future Coalition (ONE Future) [1] commissioned ICF to conduct this analysis of the marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry. The goal of this MAC analysis is threefold: (1) to identify the emission sources that provide the greatest opportunity for methane emission reduction from the natural gas system, (2) to develop a comprehensive listing of known emission abatement technologies for each of the identified emission sources, and (3) to calculate the cost of deploying each emission abatement technology and to develop a MAC curve for these emission reductions. The findings of this report will be utilized by ONE Future to develop segment-specific methane emission reduction goals that, when combined, will achieve a collective 1% (or less) emission target in the most cost-effective manner. This report will also assist each ONE Future member to customize its abatement strategy to fit its particular emission profile.

This analysis is based on a MAC curve model developed by ICF for the Environmental Defense Fund (EDF) in 2014. The current study incorporates more recent information on emissions and equipment costs and modified assumptions provided by the One Future participants. Appendix A summarizes and compares the key assumptions and results for the two studies. The study utilized the following approach:

- The baseline for methane emissions from the natural gas sector was established as the U.S. EPA Inventory of Greenhouse Gas Emissions for 2012 to match the baseline year employed in the U.S. methane emissions reduction goals.[2]
- A review of existing literature and additional analysis was conducted to identify the largest emission reduction opportunities; a cost-benefit estimate for each of the mitigation technologies was calculated.
- Interviews with One Future members, industry, technology innovators, and equipment vendors were conducted with a specific focus on identifying additional mitigation options and characterizing the cost and performance of the options.
- Information from the analysis was used to develop MAC curves for the methane reduction opportunities.

The analysis estimates reductions for each segment of the natural gas industry. The MAC analysis identified reductions totaling 88.3 Bcf/year of methane at a total annualized cost of $296 million or $3.35/Mcf of methane reduced for all segments except the distribution segment. The reductions for the distribution segment were calculated separately, and total 8.9 Bcf. An additional 12.3 Bcf of reductions were projected for the application of reduced emission completions for gas wells with hydraulic

---

[1] ONE Future is a coalition of companies that aims to achieve an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total natural gas production.

[2] This analysis was completed prior to the updates to the methodologies incorporated into the U.S. Greenhouse Gas Inventory (GHGI) on April, 15, 2016.

fracturing. This was not required in 2012 but is now legally required, and was therefore included as a reduction from the baseline but not as part of the MAC analysis. This brings the total industry-wide methane reduction to 109.5 Bcf from the 2012 baseline emissions.

2. Approach and Methodology

2.1. Overview of Methodology

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

- **Establish the 2012 Baseline for analysis** – the analysis started with the U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions (GHGI) published in April 2014 with data for 2012[3]. The most recent edition of the Inventory, released in April 2016, includes significant revisions, which are not included in this analysis. ICF expects future inventories will be updated to incorporate additional emissions and activity data collected from activities include:
  - Greenhouse Gas Reporting Program (GHGRP) inventory data collected in 2016 from companies in the gathering and boosting segment;
  - Information Collection Request (ICR)[4] for additional regulations, which will require operators to provide key activity and emissions data; and
  - Private and Government-sponsored scientific studies, including several multi-million dollar research projects focused on methane emissions from oil and gas operations sponsored by Department of Energy[5]

  Potential future updates to the GHGI may require a future update of this analysis to include those changes.

- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the 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 ONE Future Members, equipment manufacturers, other 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 analysis calculates the annualized cost of emission reductions based on the capital and operating costs of the emission reduction technologies and the value of recovered gas in the production segment. This annualized cost is divided by the emission reductions to calculate the primary figure of merit -

[3] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2012", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

[4] https://www3.epa.gov/airquality/oilandgas/methane.html

[5] http://www.netl.doe.gov/research/oil-and-gas/project-summaries/natural-gas-resources

$/unit of emissions reduced. This is expressed as $/Mcf methane reduced, $/tonne methane reduced, or $/tonne CO_2 equivalent reduced. This figure of merit is consistent with the format used in other pollution control programs (SO_2, NO_x, VOC, etc.), which typically focus on $/ton of pollutant reduced.

In the 2014 report for EDF, ICF concluded that the weighted average methane reduction cost was $0.66/Mcf of methane reduced. The annual costs were also presented as normalized by gross natural gas production, dividing the annual cost by total U.S. natural gas production. Since methane emissions are only a few percent of total production, this value is very small – less than $0.01/Mcf of gas produced in the U.S., depending on the specific assumptions. However this second metric is different from the approach typically used by industry and regulators to characterize the cost-effectiveness of emission reduction technologies and should not be compared to a $/unit of methane reduced. In addition, the ONE Future sponsor companies reported that the metric that focuses on methane reduced is more useful to companies operating in different segments in assessing technologies and opportunities at new and existing facilities within each segment. Therefore, this report employs only the more commonly used weighted annual cost per methane reduced.

2.2. Identification of Targeted Emission Sources

Table 2-1 summarizes the largest emitting source categories for the oil and gas sectors by major source category in the EPA inventory for 2012. 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 24 source categories account for nearly 90% of the total 2012 onshore methane emissions of 353 Bcf and were the primary focus of this analysis. The remaining 100+ categories each account for 1% or less of the total emissions. Although there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of these smaller sources, these source categories were not included in this analysis due to their relative minor contribution to the overall emissions and reduction opportunity. In addition, the 2014 inventory for 2012 has a limited representation[6] of the gathering segment and therefore the analysis likely does not represent the full potential reductions that could be achieved from this segment.

The distribution of emission sources is shown in Table 2-1 and Figure 2-1. Fugitive emissions are the largest emission source category overall across the oil and natural gas systems. Vented emissions from pneumatic controllers and pumps, and venting from wet seal centrifugal compressors are some of the significant methane emissions venting sources from the natural gas industry. Completion emissions from hydraulic fracturing were a significant source at this time however have since been regulated.

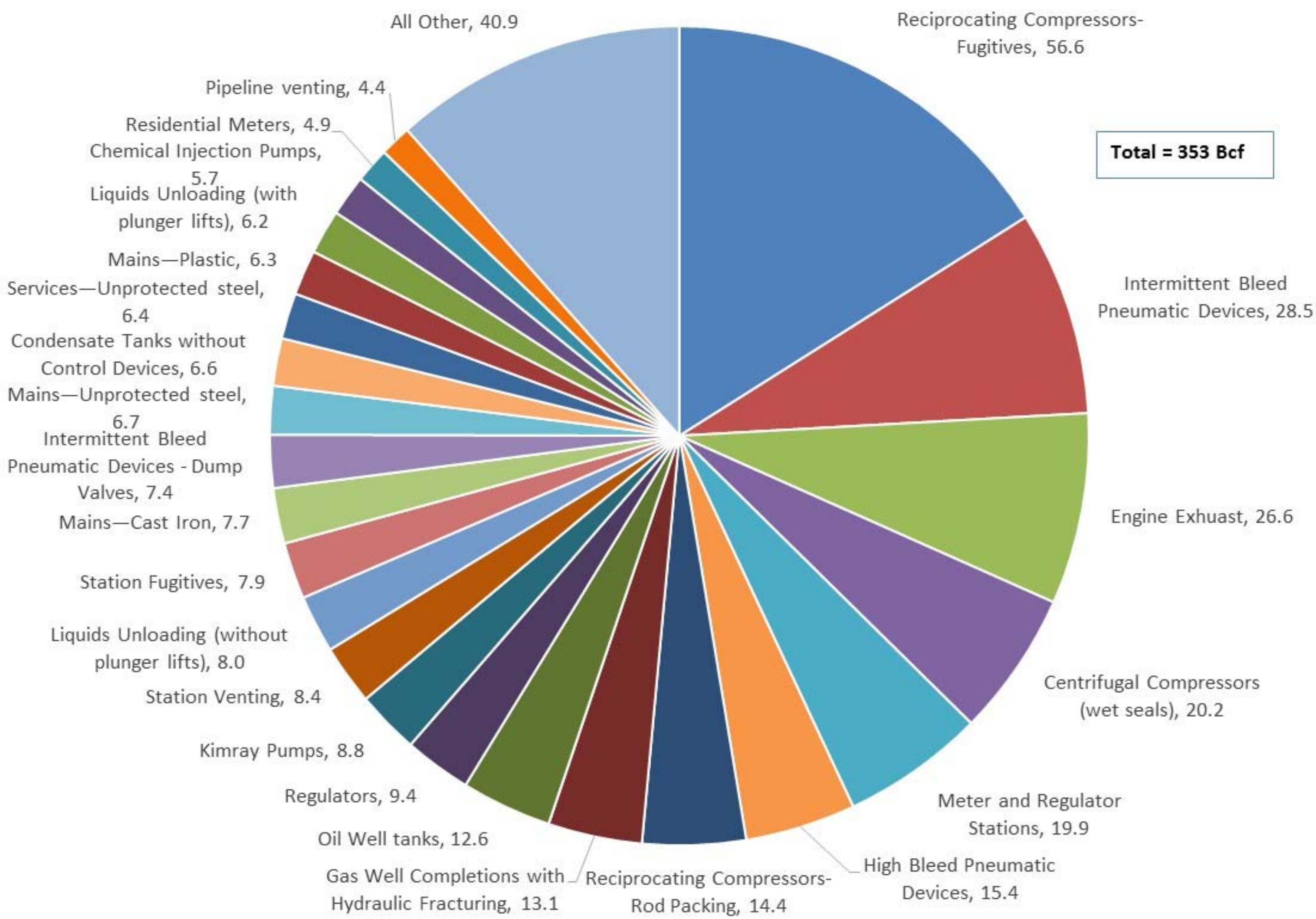
[6] See Table 1, Inventory of U.S. GHG Emissions and Sinks: Revision Under Consideration for Gathering and Boosting Emissions, February 2016

Table 2-1 - Highest (Top-24) Emitting Onshore Methane Source Categories

Source	2012 Emissions (Bcf)	Cumulative Bcf	2012 Emissions (MM tonnes)	Percent of Total	Cumulative %	Type*
Reciprocating Compressors-Fugitives	56.6	56.6	1.1	16%	16%	F
Intermittent Bleed Pneumatic Devices	28.5	85.1	0.5	8%	24%	V
Engine Exhaust	26.6	111.7	0.5	8%	32%	V
Centrifugal Compressors (wet seals)	20.2	131.9	0.4	6%	37%	V
Meter and Regulator Stations	19.9	151.9	0.4	6%	43%	F
High Bleed Pneumatic Devices	15.4	167.3	0.3	4%	47%	V
Reciprocating Compressors-Rod Packing	14.4	181.7	0.3	4%	51%	V
Gas Well Completions with Hydraulic Fracturing	13.1	194.8	0.3	4%	55%	V
Oil Well tanks	12.6	207.4	0.2	4%	59%	V
Regulators	9.4	216.7	0.2	3%	61%	V
Kimray Pumps	8.8	225.5	0.2	2%	64%	V
Station Venting	8.4	233.9	0.2	2%	66%	V
Liquids Unloading (without plunger lifts)	8.0	241.9	0.2	2%	69%	V
Station Fugitives	7.9	249.8	0.2	2%	71%	F
Mains—Cast Iron	7.7	257.5	0.1	2%	73%	F
Intermittent Bleed Pneumatic Devices - Dump Valves	7.4	264.9	0.1	2%	75%	V
Mains—Unprotected steel	6.7	271.6	0.1	2%	77%	F
Condensate Tanks without Control Devices	6.6	278.2	0.1	2%	79%	V
Services—Unprotected steel	6.4	284.6	0.1	2%	81%	F
Mains—Plastic	6.3	290.9	0.1	2%	82%	F
Liquids Unloading (with plunger lifts)	6.2	297.1	0.1	2%	84%	V
Chemical Injection Pumps	5.7	302.8	0.1	2%	86%	V
Residential Meters	4.9	307.7	0.1	1%	87%	V
Pipeline venting	4.4	312.1	0.1	1%	88%	V

- F=Fugitive V=Vented

Figure 2-1 - 2012 Onshore Emissions (Bcf) from EPA Inventory



2.3. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories identified in Table 2-1. The smaller sources individually were judged to have an insignificant effect on the overall emissions analysis even if cost-effective mitigation technologies were available. Much of the cost and performance data for the technologies is based on information from the EPA Natural Gas STAR program[7] but was updated and augmented with information provided by industry and equipment vendor sources consulted during the EDF study. Further updates and information were provided by ONE Future members for this study.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data and experiences of operators, including ONE Future members. 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. Some technologies, like the efficiency of plunger-lifts for liquids unloading to reduce emissions, depend on the operating conditions of the well. Further, certain low-production or lower utilized compressor stations may have lower emissions. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

Several of the sources identified in Table 2-1 do not have commercially available mitigation technologies (e.g., engine exhaust) or are not currently cost-effective (e.g. cast iron main replacement). ICF analyzed various mitigation options for each of the 24 sources based on cost, reduction potential and market-penetration and considered 16 sources and mitigation measures for further modeling and evaluation.

Table 2-2 summarizes the mitigation measures applied in the analysis for each of the 16 major emission sources.

Table 2-2 - Summary of Mitigation Measures Modeled

Source	Mitigation Measure
Condensate Tanks w/o Control Devices	Install vapor recovery units
Wellhead Oil Tanks w/o Control Devices	Install vapor recovery units
Liquids Unloading - Wells w/o Plunger Lifts	Install plunger lift systems in gas wells
High Bleed Pneumatic Devices	Early replacement of high-bleed devices with low-bleed devices
Intermittent Bleed Pneumatic Devices	Replace with instrument air systems – intermittent
Chemical Injection Pumps	Replace pneumatic chemical injection pumps with Solar electric pumps
Kimray Pumps	Replace Kimray pumps with electric pumps

7 http://www.epa.gov/gasstar/

Source	Mitigation Measure
Pipeline Venting	Pipeline pump-down before maintenance
Centrifugal Compressors (wet seals)	Wet seal gas capture or dry seals
Transmission Station Venting	Redesign blowdown systems and alter ESD practice
Gas Well Completions - with Fracturing	Install flares – portable
Reciprocating Compressor Rod Packing	Replacement of compressor rod packing systems
Reciprocating Compressor Fugitives[8]	Leak detection and repair (LDAR)[9]
Compressor Station Fugitives[10]	Leak detection and repair (LDAR)
Well Fugitives	Leak detection and repair (LDAR)
Gathering Station Fugitives	Leak detection and repair (LDAR)

[8] Includes blowdown and unit isolation valves, connectors, other valves, meters, open-ended lines, and PRVs that are associated with the compressors.

[9] LDAR here is used generically to mean a wide range of leak detection, inspection, and repair activities.

[10] Includes valves, connectors, meters, open-ended lines, and pressure reducing valves (PRVs) that are located throughout the station and not associated with the compressors.

Table 2-3 summarizes the key characteristics (i.e. capital costs, operating costs and reduction efficiency) of the 16 measures modeled. (The assumptions and analytical approach for LDAR are addressed further below.) The costs are for U.S. Gulf Coast and are adjusted by regional cost factors in the MAC curve analysis in Section 3. The sources and derivation of these values are listed in Appendix B. Table 2-4 shows the baseline cost effectiveness ($/Mcf, tonnes, or CO_2e of methane removed) for each measure modeled with and without credit for any recovered gas. The credit applies where emission reduction measures result in gas being recovered by the company. In the production segment, gas that is recovered can be sold and therefore has an economic value. In that case, the value of recovered gas is subtracted from the annual operating costs.

In the transmission and distribution segments, rate regulation typically requires pipeline and distribution companies to pass any cost reductions, including reduced losses, along to customers, thus the companies typically cannot capture the financial benefit of recovered gas. The contractual provisions for gathering, processing, and storage are variable but the ONE Future members reported that these companies typically do not take ownership of the gas but rather are paid a fee for their service. Reduced losses could result in increased throughput and increased recovery of the fee (which is much less than the value of the gas itself) but only if the metering point is downstream of the potential gas recovery.

Table 2-3 - Summary of Mitigation Measure Characteristics (Gulf-Coast Cost Basis)

Mitigation strategy	Capital Cost	Operating Cost	Percent Reduction
Early replacement of high-bleed devices with low-bleed devices	$3,000	$0	78%
Replacement of Reciprocating Compressor Rod Packing Systems	$6,600	$0	31%
Install Flares-Portable	$30,000	$6,000	98%
Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%
Install Vapor Recovery Units	$50,636	$9,166	95%
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%
Pipeline Pump-Down Before Maintenance	$0	$30,155	80%
Redesign Blowdown Systems and Alter ESD Practices	$15,000	$0	95%
Wet Seal Degassing Recovery System for Centrifugal Compressors	$70,000	$0	95%
Replace with Instrument Air Systems - Intermittent	$60,000	$17,770	100%

The members also reported that the metering for most of these facilities is at the entry point of the facility, thus preventing the operator from capturing the value of recovered gas. Based on this information, the value of recovered gas was included only for the production sector in this study. This is a change from the 2014 EDF study. The gas price was assumed to be $3/Mcf[11], reduced by 25% to account for royalties and fees, for a net value of $2.25/Mcf[12].

[11] EIA Short Term Energy Outlook, March 9, 2016, Henry Hub spot prices are forecast to average $3.11/MMBtu in 2017.
[12] A fuel price sensitivity analysis is included in Appendix A.

Table 2-4 – Calculated Emission Reduction Cost per Mitigation Technology or Practice (Gulf Coast Cost Basis)

Name	\$/Mcf* w/ Credit	\$/Mcf w/o Credit	\$/tonne CH4 w/Credit	\$/tonne CH4 w/o Credit	\$/tonne CO_2e ** w/Credit	\$/tonne CO_2e w/o Credit
Early replacement of high-bleed devices with low-bleed devices	\$4.91	\$7.61	\$257.01	\$398.49	\$10.28	\$15.94
Replacement of Reciprocating Compressor Rod Packing Systems	\$3.36	\$6.06	\$175.90	\$317.39	\$7.04	\$12.70
Install Flares-Portable	\$0.20	\$0.20	\$10.37	\$10.37	\$0.41	\$0.41
Install Plunger Lift Systems in Gas Wells	\$2.33	\$5.03	\$121.81	\$263.30	\$4.87	\$10.53
Install Vapor Recovery Units	-\$0.82	\$1.89	-\$42.72	\$98.76	-\$1.71	\$3.95
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	\$2.16	\$4.86	\$112.90	\$254.38	\$4.52	\$10.18
Replace Kimray Pumps with Electric Pumps	-\$1.79	\$0.91	-\$93.98	\$47.50	-\$3.76	\$1.90
Pipeline Pump-Down Before Maintenance	\$1.14	\$3.84	\$59.70	\$201.19	\$2.39	\$8.05
Redesign Blowdown Systems and Alter ESD Practices	-\$4.10	\$0.98	-\$214.62	\$51.27	-\$8.58	\$2.05
Wet Seal Degassing Recovery System for Centrifugal Compressors	-\$2.38	\$0.32	-\$124.57	\$16.91	-\$4.98	\$0.68
Replace with Instrument Air Systems - Intermittent	-\$1.46	\$1.24	-\$76.49	\$65.00	-\$3.06	\$2.60

* Gas recovery credit is applied only for the Production Segment

** GWP=25

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 later MAC analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

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 30% of the highlighted sources. The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site.

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. The analysis of LDAR cost and effectiveness for this study is a little different from the treatment of other measures because it is largely a function of labor required for inspections and repairs.

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, including for the EPA's NSPS Subpart OOOO[13] and the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)[14]. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD)[15] for NSPS Subpart OOOO as the basis for the analytical framework. Additional cost information was provided by ONE Future members.

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. ICF adapted the structure (but not all of the specific inputs) of the Colorado analysis, which calculates the capital and labor cost to field a full-time inspector, including allowances for travel and record-keeping (Table 2-5). Specific cost factors were updated based on input from the ONE Future member companies. The combined hourly cost was the basis for the cost estimates. The capital cost includes a variety of leak detection and measurement equipment, a truck and the cost of a record-keeping system. These are estimated average costs and are highly variable depending on site-

[13] http://www.epa.gov/airquality/oilandgas/

[14] http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

[15] 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

specific conditions and scale. In addition, the Gathering and Boosting segment is included in the Production segment in these analysis due to the design of the EPA inventory.

Table 2-5 - LDAR Hourly Cost Calculation

Labor			Capital and Initial Costs	
Inspection Staff	$86,155		FLIR Thermal Camera	$122,200
Supervision (@ 20%)	$17,231		Remote Methane Leak Detector (RMLD)	$20,000
Overhead (@10%)	$8,616		Photo Ionization Detector	$5,000
Travel (@0%)	$0		Flame Ionization Detector	$12,000
Recordkeeping (@5%)	$4,308		Hi-Flow Sampler	$21,450
Reporting (@0%)	$0		Miscellaneous	$3,000
Fringe (@50%)	$43,078		Truck	$22,000
Subtotal Costs	$159,387		Monitoring system	$14,500
			Total	$220,150
Hours/yr.	1880		Training Dollars	$6,782
Hourly Rate	$84.78		Amortized Capital+Training	$59,864
			Annual Labor	$207,203
Training Hours	80		Annual Total	$267,067
Training Dollars	$6,782			
			Total Hourly Rate	$142.06

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[16] and the EPA and Colorado time estimates have been criticized as too long. The estimates here are based on ICF and ONE Future company experience. ICF added additional time for training relative to the Colorado analysis.

ICF then adopted the baseline emission values for wells, gathering and transmission stations, and processing stations from the EPA NSPS analysis[15]. The 2014 EDF analysis had very limited data for LDC

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

programs and resulted in very high reduction costs. Since a different approach was taken for the LDC segment in this analysis (see below) LDCs were not included here.

Table 2-6 summarizes the assumptions for the overall LDAR calculation. This analysis assumes annual emission surveys for all facilities. The reduction is assumed to be a 40% reduction, consistent with the experience of ONE Future members. 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.

Table 2-6 – Cost Calculation – Annual LDAR

	Well Pads	Processing	Transmission
Methane Mcf/yr[15]	3,057	5,986	3,605
% Reduction	40%	40%	40%
Reduction Mcf	1,223	2,394	1,442
Hours each Inspection (includes survey, travel, recordkeeping, review and training)	5.5	40	32
Frequency (per year)	1	1	1
Annual Inspection Cost	$781	$5,682	$4,546
Initial Set-Up	$156	$1,136	$909
Repair Labor Cost	$781	$5,682	$4,546
Total Cost/yr	$1,719	$12,501	$10,001
Recovered Gas Value*	$3,303	NA	NA
Net Cost	-$1,584	$12,501	$10,001
Cost Effectiveness ($/Mcf CH_4 reduced)	-$1.30	$5.22	$6.94

*Gas at $3/Mcf minus royalty = $2.25/Mcf

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 one survey visit 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. This lower repair estimate takes into account that:

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

Replacement costs for large diameter, high pressure components are significantly greater than these average annual repair costs. The replacement frequency for large diameter, high pressure components at any individual facility cannot be accurately predicted or estimated.

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

2.4. Treatment of LDC Reductions

The 2014 EDF study found that methane emission reductions from LDCs were extremely expensive, mostly due to the low baseline emissions and the high capital cost of some options, such as cast iron pipe replacement. 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.

For this study, a separate analysis of emission reductions was developed for the LDC segment to account for reductions that will be undertaken even though they may not be cost-effective as emission control measures alone. The analysis assumed three types of activities:

- Cast iron main replacement at 3% per year
- Unprotected steel pipe replacement at 3% per year
- Miscellaneous other emission reduction measures such as: service line replacement, blowdown gas recovery, hot tapping, M&R Station upgrades, and dig-in mitigations, assumed to be 6% of the remaining emissions (excluding cast iron and unprotected steel mains) between 2012 and 2025.

Using the baseline emissions and the emission factors from the EPA 2012 inventory, these emission reductions were calculated as:

- Cast iron main replacement – 2.9 Bcf
- Unprotected steel pipe replacement – 2.5 Bcf
- Miscellaneous other emission reduction measures – 3.5 Bcf

2.5. Completion Emissions from Hydraulic Fracturing

Gas well completion emissions from hydraulic fracturing were estimated at 13.1 Bcf in the 2012 inventory. These emissions were regulated during the second half of 2012 and are assumed to be controlled going forward. Therefore they are not included in the MAC analysis but are counted as a reduction of 12.3 Bcf in the overall reductions from the base year.

2.6. 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.
- **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.
- **Gathering and Boosting** – The gathering and boosting segment is not called out as a separate segment in the 2014 edition of the EPA inventory for 2012 and therefore was not addressed as a separate source of potential reductions in this study. The 2016 edition has developed new emission factors and significantly increased the activity counts in the gathering segment, however these higher emissions and potential reductions were not included in this analysis, which was completed prior to that release. Since the GHGRP now mandates reporting of emissions data from such facilities, and with the data to be gathered by EPA pursuant to the ICR process, we expect further updates in future GHGI releases. Further, several key government-sponsored studies of emissions from gathering and boosting facilities will be published by the end of 2016. All of this data will support future updates to the methane emissions profile from this segment and available abatement potential.

3. Analytical Results

3.1. Development of Emission Control Cost Curves

Section 2 identified 16 discrete control technologies and the associated costs, reduction potential, and cost-effectiveness in terms of annualized cost per ton or Mcf of methane reduced based on Gulf Coast region capital costs. In this Section 3, we model the cumulative reductions and marginal abatement costs from a 2012 U.S. methane emissions baseline for the oil and natural gas sector, employing the technology-level data generated in Section 2. Employing data from the EPA 2012 Greenhouse Gas Inventory and source/control technology data presented in Section 2, adjusted for regional cost differences, ICF computed the methane abatement potential from the natural gas sector from a 2012 baseline.

The model developed for this task includes the individual source categories for each segment of the oil and gas industry. Mitigation technologies are matched to each source or individual measure in various segments of the oil and gas value chain. The model calculates the reduction achieved for each source within each segment 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. As discussed above, the value of recovered gas was included only for the production segment and the gas price was assumed to be $3/Mcf minus 25% for royalties and fees, for a net value of $2.25/Mcf. A 10% discount rate was used for the analysis. These calculations include two factors that were not included in the baseline costs presented in Section 2:

- A construction cost index is used to account for regional cost differences, which averages 15% higher than the baseline Gulf Coast costs.
- The methane content is adjusted depending on whether the application is upstream or downstream in the value chain. This adjustment affects the value of recovered gas where the gas value can be monetized.

These two factors result in some of the costs in the MAC curve results presented in this chapter being higher than the baseline costs presented in Section 2. These and other key assumptions are listed in Appendix A.

Table 3-1 lists the emission reduction measures by industry segment with their reduction and cost, depicted in several formats. The total reduction is 88.3 Bcf/year of methane from the U.S. oil and gas segment at a total annualized cost of $296 million or $3.35/Mcf of methane reduced from the 2012 baseline. The reductions for the LDC segment calculated separately total 8.9 Bcf and the reductions from reduced emission well completions result in a total reduction of 109.5 Bcf of methane reduction.

Table 3-1 – Annualized Methane Reduction and Cost – U.S.

Segment - Mitigation Option	Bcf CH_4 Reduced	Gg CH_4 Reduced	MMTonnes CO2e	$/Mcf CH_4 Reduced	$/Mcf Natural Gas Reduced	$/Tonne CO2e
Gas Processing - LDAR Processing	7.4	141.8	3.6	$5.98	$4.98	$12.43
Gas Processing - Replace Kimray Pumps with Electric Pumps	0.1	2.5	0.1	$1.04	$0.87	$2.16
Gas Processing - Replacement of Reciprocating Compressor Rod Packing Systems	0.3	6.0	0.2	$6.94	$5.78	$14.42
Gas Processing - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.5	144.7	3.6	$0.37	$0.31	$0.77
Gas Production - Early replacement of high-bleed devices with low-bleed devices	5.3	101.9	2.6	$6.02	$5.23	$12.50
Gas Production - Install Plunger Lift Systems in Gas Wells	2.3	43.9	1.1	$3.06	$2.66	$6.35
Gas Production - Install Vapor Recovery Units	1.6	30.1	0.8	($0.54)	($0.47)	($1.12)
Gas Production - LDAR Wells	3.3	64.2	1.6	($1.09)	($0.95)	($2.26)
Gas Production - Replace Kimray Pumps with Electric Pumps	4.3	81.8	2.1	($1.66)	($1.45)	($3.45)
Gas Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	2.7	51.4	1.3	$2.86	$2.49	$5.95
Gas Production - Replacement of Reciprocating Compressor Rod Packing Systems	0.6	11.2	0.3	$4.24	$3.69	$8.81
Gas Storage - Early replacement of high-bleed devices with low-bleed devices	0.1	1.8	0.0	$8.72	$8.14	$18.11
Gas Storage - LDAR Transmission	2.9	56.2	1.4	$7.95	$7.42	$16.51
Gas Storage - LDAR Wells	0.2	4.4	0.1	$1.61	$1.50	$3.35
Gas Storage - Redesign Blowdown Systems and Alter ESD Practices	1.2	23.4	0.6	$1.12	$1.05	$2.33
Gas Storage - Replace with Instrument Air Systems - Intermittent	0.1	2.2	0.1	$1.42	$1.33	$2.95
Gas Storage - Replacement of Reciprocating Compressor Rod Packing Systems	0.4	6.9	0.2	$6.94	$6.49	$14.42

Segment - Mitigation Option	Bcf CH_4 Reduced	Gg CH_4 Reduced	MMTonnes CO2e	\$/Mcf CH_4 Reduced	\$/Mcf Natural Gas Reduced	\$/Tonne CO2e
Gas Storage - Wet Seal Degassing Recovery System for Centrifugal Compressors	0.8	14.5	0.4	\$0.37	\$0.35	\$0.77
Gas Transmission - Early replacement of high-bleed devices with low-bleed devices	0.5	9.5	0.2	\$8.72	\$8.14	\$18.11
Gas Transmission - LDAR Transmission	14.0	268.5	6.7	\$7.95	\$7.42	\$16.51
Gas Transmission - Pipeline Pump-Down Before Maintenance	2.8	53.9	1.4	\$4.40	\$4.11	\$9.14
Gas Transmission - Redesign Blowdown Systems and Alter ESD Practices	6.4	122.5	3.1	\$1.12	\$1.05	\$2.33
Gas Transmission - Replace with Instrument Air Systems - Intermittent	0.6	11.2	0.3	\$1.42	\$1.33	\$2.95
Gas Transmission - Replacement of Reciprocating Compressor Rod Packing Systems	1.8	35.4	0.9	\$6.94	\$6.49	\$14.42
Gas Transmission - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.4	141.6	3.6	\$0.37	\$0.35	\$0.77
Oil Production - Early replacement of high-bleed devices with low-bleed devices	4.6	88.5	2.2	\$6.02	\$5.01	\$12.50
Oil Production - Install Vapor Recovery Units	6.0	114.7	2.9	(\$0.54)	(\$0.45)	(\$1.12)
Oil Production - LDAR Wells	0.0	0.3	0.0	(\$1.09)	(\$0.91)	(\$2.26)
Oil Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	1.9	36.1	0.9	\$2.86	\$0.00	\$5.95
Oil Production - Replace with Instrument Air Systems - Intermittent	1.1	20.6	0.5	(\$1.28)	\$0.00	(\$2.66)
Total	**88.3**	**1,699.8**	**0.9**			
Gas Production - Reduced Emission Completions	12.3	236.4	5.9	N/A	N/A	N/A
Gas Distribution - Cast Iron Main Replacement	2.9	55.6	1.4	N/A	N/A	N/A
Gas Distribution - Bare Steel Replacement	2.5	47.9	1.2	N/A	N/A	N/A
Gas Distribution - Miscellaneous	3.5	67.1	1.7	N/A	N/A	N/A
Grand Total	**109.5**	**2,106.8**	**11.1**			

The results can also be presented as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 3-1. 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 3-1 – Example MAC Curve

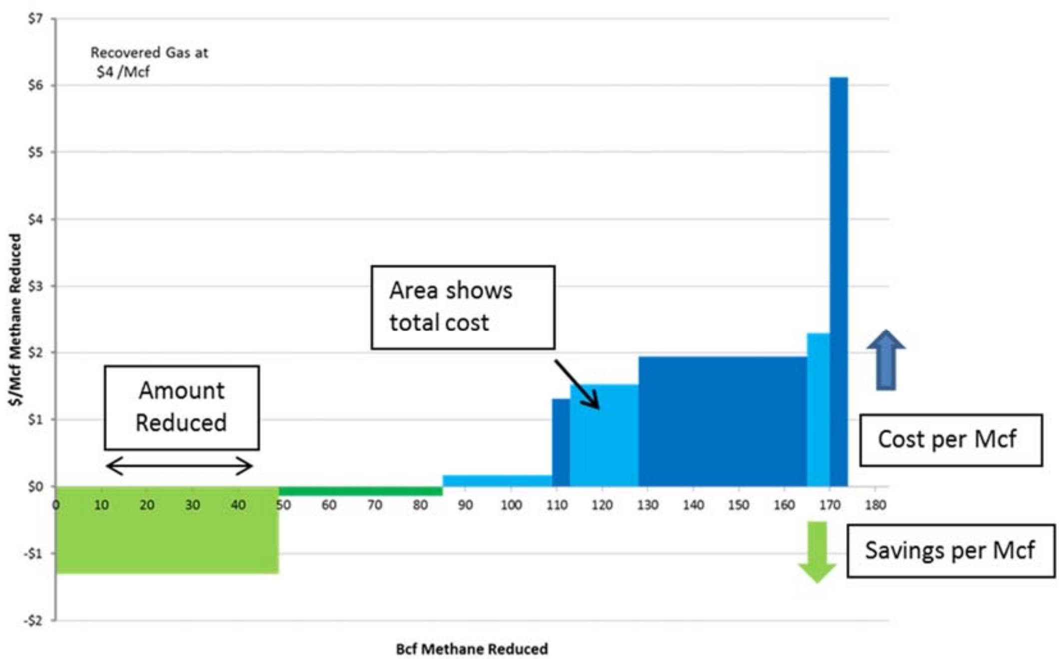


Figure 3-2 shows the reduction for each measure across all industry segments in the MAC curve format. Figure 3-3 shows the reduction in methane emissions by industry segment. The transmission and production sectors have the greatest reductions. The costs for each sector depend on the particular mitigation options available in each and their aggregate cost.

Figure 3-2 – National Aggregate MAC Curve by Measure

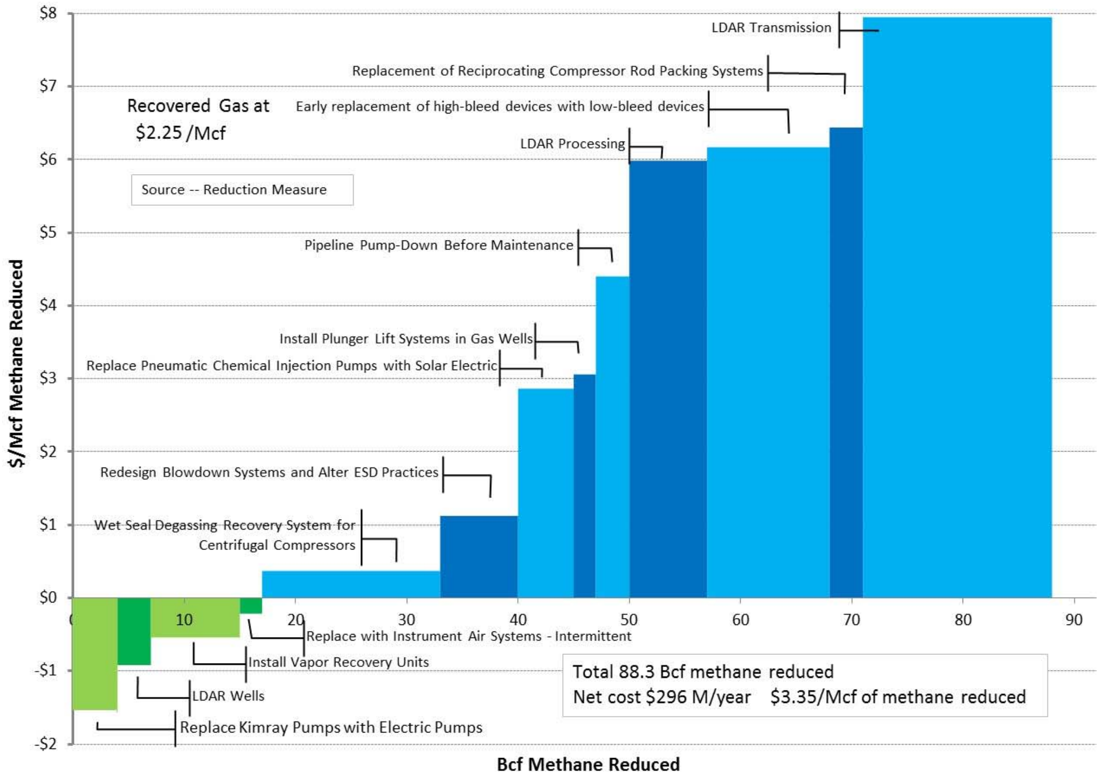
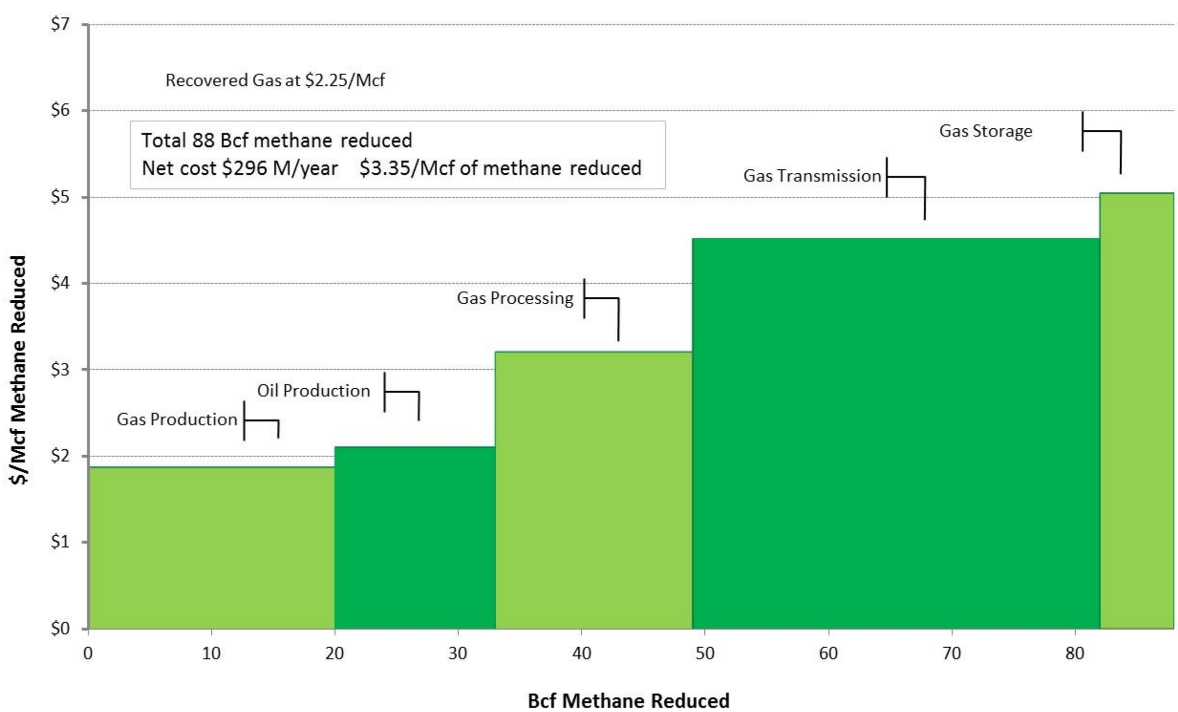


Figure 3-3 – National Aggregate MAC Curve by Industry Segment



Appendix A.
Summary and Comparison of Assumptions and Results

This section summarizes and compares the key assumptions and results for this study and the 2014 EDF study. The assumptions for each study were largely specified by the clients for each. Table A-1 summarizes some of the key assumptions and results. The primary difference in total reduction volume is the lower reduction from less frequent LDAR and the smaller baseline in the current study due to a different base year and exclusion of the distribution segment.

Table A-1 - Summary of Baseline Assumptions and MAC Curve Results

	ONE Future 2016	EDF 2014
Inventory Baseline	EPA Inventory 2012 – 353 Bcf methane	EPA Inventory 2011 modified and projected to 2018 – 404 Bcf methane
Natural Gas Price	$2.25/Mcf ($3/Mcf – 25% royalty and fee payments)	$4/Mcf
LDAR Frequency and reduction	Annual – 40%	Quarterly – 60%
Gas Value Credit for Reductions	Production segment only	All except transmission and distribution
Net Annualized Cost	$296 million	$108 million
Annual reduction	88.3 Bcf methane	163 Bcf methane
Average cost of reduction	$3.35/Mcf methane reduced	$0.66/Mcf methane reduced

The primary drivers of the difference in the average cost of reduction between the two studies are the different gas price and the assumptions on which sectors can monetize the value of recovered gas. Table A-2 provides a sensitivity analysis of the gas price effect on the annualized cost of reduction per Mcf.

Table A-2 – Cost per Mcf of Methane Reduced – Gas Price Sensitivity

Gas Price	ONE Future 2016	EDF 2014
$2.25/Mcf	$3.35	
$3.00/Mcf	$3.01	$1.48
$4.00/Mcf	$2.55	$0.66
$5.00/Mcf		-$0.15

Table A-3 - Mitigation Technology Characteristics – ONE Future 2016

Mitigation strategy	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	78%	$4.91	$7.61
Replacement of Reciprocating Compressor Rod Packing Systems	$6,600	$0	31%	$3.36	$6.06
Install Flares-Portable	$30,000	$6,000	98%	$0.20	$0.20
Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%	$2.33	$5.03
Install Vapor Recovery Units	$50,636	$9,166	95%	-$0.82	$1.89
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%	$2.16	$4.86
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%	-$1.79	$0.91
Pipeline Pump-Down Before Maintenance	$0	$30,155	80%	$1.14	$3.84
Redesign Blowdown Systems and Alter ESD Practices	$15,000	$0	95%	-$4.10	$0.98
Wet Seal Degassing Recovery System for Centrifugal Compressors	$70,000	$0	95%	-$2.38	$0.32
Replace with Instrument Air Systems - Intermittent	$60,000	$17,770	100%	-$1.46	$1.24

Table A-4 – Mitigation Technology Characteristics – EDF 2014

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

Table A-5 – Annualized Cost and Reduction Comparison

	EDF 2014			ONE Future 2016		
Source/Measure	Annualized Cost ($ million/yr)	Bcf Methane Reduced/yr	$/ MCF Methane Reduced	Annualized Cost ($ million/yr)	Bcf Methane Reduced/yr	$/ MCF Methane Reduced
Replace Kimray Pumps with Electric Pumps	-$23.4	5.8	-$4.05	-$7.0	4.4	-$1.58
Wet Seal Degassing Recovery System for Centrifugal Compressors	-$58.7	19.1	-$3.07	$5.8	15.7	$0.37
Compressor Stations (Storage)--LDAR	-$4.5	1.5	-$3.03	Included in Transmission		
Early replacement of high-bleed devices with low-bleed devices	-$67.4	25.4	-$2.65	$64.9	10.5	$6.17
Reciprocating Compressor Fugitives--LDAR	-$10.5	32.3	-$0.33	Included in Transmission		
Condensate Tanks w/o Control Devices--VRU	$0.1	0.4	$0.21	-$4.1	7.6	-$0.54
Stranded Gas Venting from Oil Wells--Flares	$2.4	8.2	$0.30	NA		
Oil Tanks--VRU	$1.8	5.5	$0.33	Included with Condensate Tanks		
Pipeline Pump-Down Before Maintenance	$2.3	4.2	$0.53	$12.4	2.8	$4.40
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$2.7	4.8	$0.57	$13.1	4.6	$2.86
Install Plunger Lift Systems in Gas Wells	$1.2	1.6	$0.74	$7.0	2.3	$3.06
Redesign Blowdown Systems and Alter ESD Practices	$7.5	5.9	$1.27	$8.5	7.6	$1.12
Gathering and Boosting Stations--LDAR	$5.0	3.3	$1.51	Included in Production		
Intermittent Bleed Pneumatic Devices--Low Bleed	$20.9	12.1	$1.72	NA		
Replace with Instrument Air Systems - Intermittent	NA			-$0.4	1.8	-$0.22
Oil Well Completions - with Fracturing--Flares	$14.5	6.8	$2.13	NA		
Compressor Stations (Transmission)--LDAR	$7.7	2.8	$2.79	$134.3	16.9	$7.95
Well Fugitives--LDAR	$43.9	12.5	$3.51	-$3.3	3.6	-$0.92

Replacement of Reciprocating Compressor Rod Packing Systems	$22.3	3.6	$6.11	$20.0	3.1	$6.44
LDC Meters and Regulators--LDAR	$140.6	7.1	$19.75	NA		
Grand Total	**$108.3**	**162.9**	**$0.66**	**$295.9**	**88.3**	**$3.35**

Appendix B.
Data Sources

The follow notes explain the sources and derivation of the capital cost (Capex), operating cost (Opex), and emission reduction potential of the emission reduction options assessed in this study. The primary sources are a variety of EPA sources – particularly data from the Gas STAR program, the Greenhouse Gas Reporting, and support documents from NSPS OOOO, as well as industry comments received during the 2014 EDF study, and comments from the ONE Future sponsors of this study. Each emission reduction option is discussed below:

- **Early replacement of high-bleed devices with low-bleed devices** – Capex $3,000, Opex $0, Reduction 78%. The Capex and Opex were based on Gas STAR data updated by industry review in both studies. There is no incremental Opex for pneumatic devices. The reduction estimate was based on the performance of high bleed and low bleed pneumatic devices found in two field measurement studies completed by the University of Texas [17, 18] and sponsored by industry participants and EDF.
- **Replacement of Reciprocating Compressor Rod Packing Systems –** Capex $6,600, Opex $0, Reduction 31%. The Capex was based on Gas STAR data updated by industry in both studies. There is no incremental Opex for this measure. The reduction estimate was based on an analysis by ICF that calculates the reductions due to more frequent replacement of rod packing seals relative to less frequent replacement.
- **Install Flares-Portable** – Capex $30,000, Opex $6,000, Reduction 98%. The Capex and Opex were based on industry input during both the EDF and ONE Future studies. The reduction is an EPA Gas STAR/inventory assumption of 98% flare combustion efficiency. Additional information was derived from GHGRP Subpart W.
- **Install Plunger Lift Systems in Gas Wells** – Capex - $20,000, Opex $2,400, Reduction 95%. These values were based on industry input during both studies. They do not include the value of increased production, which is typically the primary driver for liquids unloading. The cost and effectiveness of plunger lifts are highly variable depending on the well characteristics. Plunger lifts can be an effective mitigation measure for certain wells at certain times over their operating life but may not

[17] Allen, David T. et al. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences of the United States of America* 110.44 (2013): 17768–17773.

[18] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers. David T. Allen et al. Environmental Science & Technology 2015 49 (1), 633-640. DOI: 10.1021/es5040156. Available online at: http://pubs.acs.org/doi/abs/10.1021/es5040156

be effective or feasible for other wells or even for the same well at a different point in its operating life. Applicability information was derived from GHGRP subpart W.

- **Install Vapor Recovery Units –** Capex $50,636, Opex $9,166, Reduction 95%. These values were based on EPA Gas STAR data, independent ICF analysis, and updates from vendors and industry commenters in both studies.
- **Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps -** Capex $5,000, Opex $75, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace Kimray Pumps with Electric Pumps** – Capex $10,000, Opex $2,000, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Pipeline Pump-Down Before Maintenance** – Capex $0, Opex $30,155, Reduction 80%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies. The required equipment is typically leased so there is no Capex.
- **Redesign Blowdown Systems and Alter ESD Practices** - Capex $15,000, Opex $0, Reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Wet Seal Degassing Recovery System for Centrifugal Compressors** – Capex $70,000, Opex $0, reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace with Instrument Air Systems – Intermittent** – Capex $60,000, Opex $17,770, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **LDAR Costs** – The structure of the LDAR cost analysis is different from the other measures, as discussed in the body of the report. The cost analysis structure is based on the regulatory analysis for the Colorado methane rule but most of the values have been updated. The ONE Future sponsors provided extensive input on the labor and instrumentation costs. The baseline labor costs were increased and the number of measurement devices was increased from the Colorado assumptions. The time allocated for inspections was also increased relative to the 2014 EDF report based on input from the sponsors. The baseline emissions were from the EPA Technical Support Document for NSPS OOOO.