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[2025-0117 PTE Proposed Reductions.pdf](#)

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Good morning Mark, Sheri, and Devin,

I am passing along some information that we pulled together:

MPLX is proposing a permit condition requiring semi-annual OGI monitoring and leak repair on connectors and flanges for a 90% reduction on the AP-42 factor. In the attached document from EPA, they estimate that a semi-annual OGI program has the results of reducing emissions by 60%. This is written in the 2<sup>nd</sup> paragraph on Page 52 of the attached document. Through Method 21 monitoring and AVO inspections we are able to achieve a 75% reduction rate from AP-42 according to TCEQ. By adding a semi-annual OGI monitoring program of connectors we can expect an additional 60% reduction, setting us at a 90% reduction from raw AP-42 emission rates.

Additionally, MPLX is proposing to take a permit condition requiring the installation of low-emission valves on valves 1" or greater for a 99% reduction on the AP-42 factor. The EPA definition of "Low-E valve" as presented in the MarkWest LDAR Consent Decree (page 16 of the CD) is listed below:

"Low-Emission Valve" or Low-E Valve" shall mean either of the following :

- i. A valve (including its specific packing assembly of stem sealing component) for which the manufacturer has issued a written warranty that it will not emit fugitives at greater than 100 pm, and that, if it does so emit at greater than 100 ppm at any time in the first five years after installation the manufacturer will replace the valve; provided, however, that no valve shall qualify as "Low-E" by reason of written warranty unless the valve (including its specific packing assembly) either:
  - a. first was test by the manufacturer or a qualified testing firm pursuant to the generally-accepted good engineering practices for testing fugitive emissions; or
  - b. is an "extension" of another valve that qualified as "Low-E" under Subparagraph i above; or
- ii. A valve (including its specific packing assembly) that:
  - a. Has been tested by the manufacturer or a qualified testing firm pursuant to generally-accepted good engineering practices for testing fugitive emissions and that, during the test, at no time leaked at greater than 500 ppm, and on average, leaked at less than 100 ppm; or
  - b. Is an "extension" of another valve that qualified as "Low-E" under Subparagraph i above.

For purposes of Subparagraphs (i)(b) and (ii)(b), being an “extension of another valve” means that the characteristics of the valve that affect sealing performance (e.g., type of valve, stem motion, tolerances, surface finishes, loading arrangement, and stem and body seal material, design, and construction) are the same or essentially equivalent as between the tested and the untested valve.

Please see the summary of historical Harmon Creek LDAR VOC information to support the proposed reductions:

Based on AP-42 Correlation Equations from actual PPM readings during Method 21 Monitoring events.

	Actual Average Reduction from AP-42	Proposed Connector Reduction	Actual Average Valve Reduction from AP-42	Proposed Valve Reduction
Year	%	%	%	%
2020	95.28%	90%	99.61%	99%
2021	95.37%	90%	99.63%	99%
2022	96.25%	90%	99.63%	99%
2023	96.51%	90%	99.65%	99%
2024	95.65%	90%	99.56%	99%
5-year average	95.81%		99.62%	

Finally, MPLX is proposing to reduce the throughput on the open flare. Justification for the flare throughput was provided in response to technical deficiencies and the planned installation of a vapor recovery unit with a capacity of 2000 MSCFD is anticipated to reduce the throughput significantly. MPLX is proposing a throughput limit of 116.518 mmscf/yr, which includes sweep gas.

Can we schedule a meeting early next week to discuss any questions you may have? If you have any questions prior to that call, let us know.

Thank you!



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# Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

Background Technical Support Document for the  
Final New Source Performance Standards  
40 CFR Part 60, subpart OOOOa

May, 2016

**Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources**

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**DISCLAIMER**

This report has been reviewed by Environmental Protection Agency's (EPA) Office of Air Quality Planning and Standards (OAQPS) and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

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**ACRONYMS AND ABBREVIATIONS**

<b><u>Acronyms/Abbreviations</u></b>	<b><u>Description</u></b>
µg/L	micrograms per liter
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
bbl	barrels
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
CAA	Clean Air Act
CAGR	compound annual growth rate
CD	combustion device
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
cfm	cubic foot per minute
CFR	U.S. Code of Federal Regulations
CH <sub>4</sub>	methane
CIPs	chemical injection pumps
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CO <sub>2</sub> Eq.	carbon dioxide equivalents
COOGCC	Colorado Oil and Gas Conservation Commission
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FR	Federal Register
GE	General Electric
GHG	greenhouse gas
GOR	gas to oil ratio
GRI	Gas Research Institute
H <sub>2</sub> S	hydrogen sulfide
HAP	hazardous air pollutants
Inj/With	injection/withdrawal
IR	infrared
kg/hr/comp	kilograms per hour per component
kg/hr/source	kilograms per hour per source
kW	kilowatt
lbs	pounds
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf	million cubic feet
MMT	million metric tons

<b><u>Acronyms/Abbreviations</u></b>	<b><u>Description</u></b>
MMtCO <sub>2</sub> e	million metric tons of CO <sub>2</sub> -equivalents
Mscf	thousand standard cubic feet
Mscf/cyl	thousand standard cubic feet per cylinder
Mscf/yr	thousand standard cubic feet per cylinder per year
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO <sub>x</sub>	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations & maintenance
OAQPS	Office of Air Quality and Standards
OAR	Office of Air and Radiation
OEL	open-ended line
OGI	optical gas imaging
OVA	organic vapor analyzers
PES	Preliminary Environmental Study
PG&E	Pacific Gas & Electric
PM	particulate matter
PNAS	Proceedings of the National Academy of Sciences
ppmv	parts per million by volume
PRV	pressure relief valve
psig	pounds per square inch gage
REC	renewable energy certificate
scf	standard cubic feet
scf/hr-cylinder	standard cubic feet per hour-cylinder
scf/minute or scfm	standard cubic feet per minute
scfh	standard cubic feet per hour
SO <sub>2</sub>	sulfur dioxide
THC	total hydrocarbon
TOC	total organic compounds
tpy	tons per year
TSD	Technical Support Document
TVA	toxic vapor analyzers
U.S.	United States
U.S.C.	United States Code
URS Corporation	United Research Services Corporation
UT Austin	University of Texas, Austin
VOC	volatile organic compounds
VRU	Vapor recovery unit
WAQD	Wyoming's Air Quality Division

## **1.0 INTRODUCTION**

This background technical support document (TSD) provides information relevant to the development of the final rule Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. The final rule establishes GHG standards, in the form of limitations on methane, for certain sources that are currently regulated for VOC but not GHG. It also establishes both VOC and GHG standards certain sources that are currently unregulated for either emissions.

Chapter 2 presents an overview of the oil and natural gas sector and source category. This chapter is intended to provide introductory material on the oil and natural gas source category, as listed under section 111(b)(1)(A).

The remainder of the TSD is presented in two volumes; Volume 1 provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER); and Volume 2 presents the national impacts of the regulatory decisions for the final rule.

### **1.1 Volume 1 - Unit-Level BSER Analysis**

Chapters 3 through Chapter 7 present detailed information and analyses pertaining to each emissions source that was considered in this regulatory action. They include emission data and discussions of available control options and their costs that are considered in the development of standards reflecting the BSER for these emission sources.

### **1.2 Volume 2 - National Level Impacts**

Chapters 8 through Chapter 15 present the estimates of national level impacts needed to inform the Preamble of the final rule and the Regulatory Impact Analysis (RIA) for the rule, as required under Executive Order 12866. Specifically, each chapter summarizes the national baseline, nationwide emission reductions and cost impacts for use in the Preamble and RIA. It is important to note that that national impacts estimates incorporate in to the baseline the fact that some states already have requirements of emissions sources addressed by this final rule. Further, this analysis is separate and apart from the analyses required to identify the BSER based on which standards are to be established under section 111(b) of the CAA. Chapter 13 summarizes the natural gas savings from the application of emissions controls.

Finally, the Appendix to the TSD provides technical information on the background and development of the low pressure well equation.

### 1.3 Supporting Documentation

This action follows the development of several prior oil and gas NSPS related actions. This review references several documents that were published as a consequence of these prior actions. For ease of presentation, the following documents are consistently cited in the following sections:

- The TSD for the 2011 NSPS proposal, published in July, 2011, will be referred to in this document as "2011 NSPS TSD".<sup>1</sup>
- The supplemental TSD for the 2012 final NSPS standards, published April, 2012, will be referred to in this document as "2012 NSPS STSD".<sup>2</sup>
- The gas composition memo that was developed during the NSPS process which characterizes and analysis of data to determine the gas composition and develop ratios for natural gas composition to be used for the various segments in the development of regulations for the oil and natural gas sector. This document will be referred to as "2011 Gas Composition Memorandum".<sup>3</sup>
- Emissions information and counts for various emission sources were developed from facility-level data submitted to the Greenhouse Gas Reporting Program (GHGRP) and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks. The most recent available data from the GHG Inventory at the time of the development of this analysis was for 2013, and was used for various portions of the analysis. For the purposes of this document these data sources are referred to as "GHGRP" and "GHG Inventory". Currently available GHGRP reported data cover 2011 through 2014 and the most recent available GHG Inventory covers data from 1990-2014.<sup>4</sup> These new activity data have been reviewed for the final rule and incorporated into this analysis appropriate
- The TSD for the 2015 NSPS proposal, published in August, 2015, will be referred to in this document as "2015 NSPS Proposal TSD". Note that this TSD includes all information from the proposal TSD that did not change and that continues to support the decisions of final rule, as well

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<sup>1</sup> U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.

<sup>2</sup> U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for Proposed Standards*. April 2012. Docket ID EPA-HQ-OAR-2010-0505-4550.

<sup>3</sup> Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural gas Sector Rulemaking". July 2011. Docket ID EPA-HQ-OAR-2010-0505-0084.

<sup>4</sup> U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC

any revisions to relevant data or information that supports the provisions of the final rule.<sup>5</sup>

All of the calculations supporting the analyses in this document are included in the docket in the form of spreadsheets that are labeled corresponding to the section of the TSD.

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<sup>5</sup> See EPA-HQ-OAR-2010\_0505-5021



## **2.0 OIL AND NATURAL GAS SOURCE CATEGORY OVERVIEW**

The final rule covers emission sources within the oil and natural gas source category, which includes onshore crude oil production and natural gas production, processing, transmission and storage.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treatment of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and gas wells. Oil wells can have “associated” natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H<sub>2</sub>S), carbon dioxide (CO<sub>2</sub>), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce “pipeline quality” dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids,

sulfur and CO<sub>2</sub> removal, fractionation of natural gas liquid and other processes, such as the capture of CO<sub>2</sub> separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

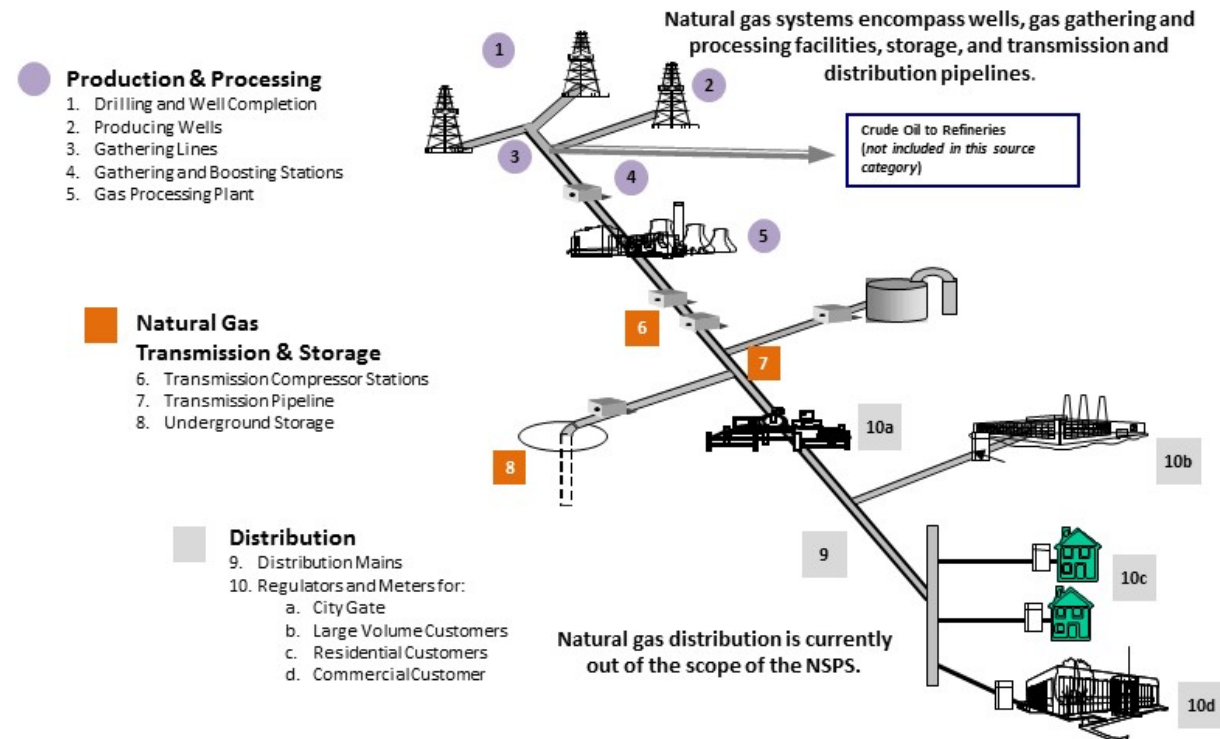
Emissions can occur from a variety of processes and points throughout the oil and natural gas source category. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO<sub>2</sub> are emitted from production and processing operations that handle and treat sour gas.<sup>6</sup>

The analysis in this document addresses only emission sources in the oil and natural gas source category. Unless otherwise noted, use of the term "gas" refers to natural gas.

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<sup>6</sup> Sour gas is defined as natural gas with a maximum H<sub>2</sub>S content of 0.25 gr/100 scf (4 parts per million by volume (ppmv)) along with the presence of CO<sub>2</sub>.

## Oil and Gas Sector Description



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

**Figure 1. Oil and Natural Gas Sector Operations**

## **VOLUME 1: UNIT LEVEL BSER ANALYSIS**

### **3.0 HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS**

During development of the 2012 NSPS amendments, methane and VOC emissions from hydraulically fractured oil and natural gas well completions and recompletions were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD. The 2012 NSPS promulgated requirements for control of emissions from hydraulically fractured natural gas well completions and recompletions.

The EPA has reevaluated hydraulically fractured oil well completion emissions based on more recent data and information as discussed below. As was determined with respect to gas wells, oil well completions and recompletions use multi-phase processes with various sources of emissions where the highest emissions result from the venting of natural gas to the atmosphere during flowback. The flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes hydraulically fractured oil well completions and recompletions, and provides estimates for representative oil wells and nationwide emissions. With respect to control technology, the same control technology can be employed to control emissions from oil well completions as were found to be appropriate for gas well completions. In this chapter, the EPA evaluated costs, emission reductions, and secondary impacts for oil well completions and recompletions based on the revised emissions profile.

Because oil well completions and recompletions were included in the proposed NSPS amendments in 2011 (76 FR 52738), for the sake of convenience the EPA repeat below the process description and control technology discussions from the 2012 NSPS TSD with minimal edits.

#### **3.1 Process Description**

##### *3.1.1 Oil Well Completions*

All oil wells must be “completed” after initial drilling in preparation for production.

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and

gathering lines are installed as necessary for production to begin.<sup>7</sup>

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rates of various phases (oil, gas, and water), oil API gravity, and pressure and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as “wildcat”) wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving oil production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Natural gas emissions are a result of the flowback of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion flowback escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the flowback eventually contains a higher volume of natural gas from the formation. Due to the specific additional equipment and resources involved and the nature of the flowback of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

*3.1.2 Oil Well Recompletions* Recompletions are remedial operations conducted to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere

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<sup>7</sup> U.S. EPA. Lessons Learned: Reduced Emissions Completions. Office of Air and Radiation (OAR): Natural Gas Star Program, Washington, DC, 2011.

unless the flowback gas is captured.

When hydraulic re-fracturing (recompletions) is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The flowback velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Flowback emissions are a result of free gas being produced by the well following hydraulic fracturing during a well completion and recompletion activity. The high rate flowback, with intermittent slugs of water and sand along with free gas, is directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the flowback emissions originate from the recompletion process but may be vented as the flowback enters the impoundment or vessels.

## 3.2 Emission Data and Emission Factors

### 3.2.1 Summary of Major Studies and Emission Factors

Together with the sources of information and data reviewed during the development of the 2012 NSPS, the EPA reviewed recent data and information as was discussed in the white paper titled "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production" published by the EPA in April, 2014.<sup>8</sup> Table 3-1 presents a list of the studies and information sources consulted for development of the NSPS and the 2014 white paper. The list below includes sources with information on hydraulically fractured gas and oil well completions and workovers.

**Table 3-1. Major Studies Reviewed Emissions and Activity Data**

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Drilling Info database	HPDI	2015	Nationwide	X	
GHG Mandatory Reporting Rule and Technical Supporting Documents <sup>a</sup>	EPA	2013	Nationwide	X	

<sup>8</sup> Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf>.

<b>Report Name</b>	<b>Affiliation</b>	<b>Year of Report</b>	<b>Activity Factor(s)</b>	<b>Emission Information</b>	<b>Control Information</b>
Inventory of GHG Emissions and Sinks: 1990-2013 <sup>b, c</sup>	EPA	2015	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry (Draft) <sup>d</sup>	Radian	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry <sup>e</sup>	ICF	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States <sup>f</sup>	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories <sup>g</sup>	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State <sup>h</sup>	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Oil and Natural Gas Production Facilities <sup>i</sup>	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data <sup>j</sup>	U.S. Energy Information Administration (EIA)	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations <sup>k</sup>	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program <sup>l</sup>	New York State Department of Environmental Conservation	2009	Regional	X	X
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 <sup>m</sup>	EPA	2012	Nationwide	X	X
Fort Berthold Federal Implementation Plan <sup>n</sup>	EPA	2012	Regional	X	X
ERG/EC/R Contractor Analysis of HPDI® Data <sup>o</sup>	EPA	2012	Nationwide	X	X
Environmental Defense Fund Analysis of HPDI Data <sup>p</sup>	EDF	2014	Nationwide	X	X

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Measurement of Methane Emissions at Natural Gas Production Sites in the United States <sup>q</sup>	Allen et al.	2014	Nationwide	X	X
Methane Leaks from North American Natural Gas Systems <sup>r</sup>	Brandt et al.	2014	Nationwide	X	X

- a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010. 84-89 pp.
- b. U.S. EPA. Annex 3.5: Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Petroleum Systems. Inventory of GHG Emissions and Sinks: 1990-2013. Washington, DC. 2015.
- c. U.S. EPA. Annex 3.6: Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Natural Gas Systems. Inventory of GHG Emissions and Sinks: 1990-2013. . Washington, DC. 2015.
- d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.
- e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.
- f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.
- g. ENVIRON International Corporation. Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership. November 2008.
- h. Independent Petroleum Association of America. Oil and Gas Producing Industry in Your State. 2008.
- i. Eastern Research Group, Inc. Emissions from Oil and Gas Production Facilities. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
- j. U.S. EIA. Annual U.S. Natural Gas Wellhead Price. EIA. Natural Gas Navigator. Retrieved December 12, 2010. <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.
- k. ERG, Inc. Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations. Prepared for the U.S. EPA. September 1999.
- l. New York State Department of Environmental Conservation. Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (DRAFT). September 2009.
- m. See footnote 2.
- n. Fort Berthold Indian Reservation Federal Implementation Plan (78 FR 17836). U.S. Environmental Protection Agency (U.S. EPA). 2012a. *Technical Support Document, Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), North Dakota*. Docket Number: EPA-R08-OAR-2012-0479.U.S. EPA.
- o. Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production. Washington, CD. 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf>.
- p. Environmental Defense Fund (EDF). 2014. *Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses, March, 2014*. Available at <http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf>. Supplemental materials available at <https://www.dropbox.com/s/osrom4w6ewow4ua/EDF-Initial-Production-Cost-Effectiveness-Analysis.xlsx>.
- q. Proceeding of the National Academy of Sciences of the United States of America (PNAS). 2013. *Measurement of Methane Emissions at Natural Gas Production Sites in the United States*. August 19, 2013. Available at <http://www.pnas.org/content/early/2013/09/10/1304880110.abstract>.
- r. Brandt, A.R., et al. 2014a. *Methane Leaks from North American Natural Gas Systems*. Science 343, 733 (2014). February 14, 2014. Available at <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>.

### 3.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion



and recompletion emissions are estimated as the venting of emissions from the well following hydraulic fracturing during a well completion or recompletion activity.

This analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. The basic approach for this analysis was to use natural gas production data to approximate natural gas emissions from representative oil well completions and recompletions and then estimate methane and VOC emissions using the representative gas composition values developed in the 2011 Gas Composition Memorandum for the 2012 NSPS.<sup>9</sup>

Based on the comments received during the development of the NSPS, the EPA recognized that there are instances where gas produced by a well is incidental to oil production and that the gas flow would not support operation of a separator if low levels of gas produced. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. EIA data show that the number of "oil only" wells drilled from 2007-2012 was less than 20 percent.<sup>10</sup> Therefore, the EPA evaluated available information to determine a minimum threshold of gas produced.

Non-volatile "black oils" (oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900.<sup>11</sup> Therefore, oil wells with GORs less than 300 are at the lower end of this range, and likely will not have enough associated gas that can be separated.<sup>12</sup> Based on this consideration, the EPA concludes that a separator will not function at a well with a GOR of less than 300 scf/barrel and, therefore, well completion of such well would not be reasonably capable of capturing and controlling emissions. Consequently, removed these oil wells from our analysis conducted to determine emissions from hydraulically fractured oil wells.

The following methodology was used to estimate the potential methane and VOC emissions from hydraulically fractured oil well completions.

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<sup>9</sup> See U.S. EPA Docket ID Number EPA-HQ-OAR-2010-0505-0084.

<sup>10</sup> <http://www.eia.gov/todayinenergy/detail.cfm?id=13571#>

<sup>11</sup> [http://petrowiki.org/Oil\\_fluid\\_characteristics](http://petrowiki.org/Oil_fluid_characteristics)

<sup>12</sup> The reason for the proposed threshold GOR of 300 was that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field. On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.

<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137>.

1. The EPA obtained well production data from the DrillingInfo database dated February, 2014.<sup>13</sup> The DrillingInfo database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. DrillingInfo collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. The data extract from the DrillingInfo database included the population of all wells with gas or hydrocarbon liquid production during 2010 to 2012 and with a recorded completion year of 2010 to the date of the extract (February, 2014).
2. The data was then processed to identify oil wells that were hydraulically fractured using a methodology based on a crosswalk of formation types and other information. See the ERG memorandum titled "*2013 GHGRP Subpart W and NSPS/NESHAP DrillingInfo Processing Methodology*" available in the docket, for a detailed description of the process to identify hydraulically fractured oil wells from the total oil well population.
3. From the dataset of hydraulically fractured oil wells, the EPA identified the wells completed in 2012 using the "completion year" record or the year of the "first month of production". Wells with a completion year of 2012 could have been completed for the first time in 2012 or could have been re-completed (i.e., re-fractured in 2012). The EPA also removed from the dataset all wells not characterized in the DrillingInfo database as "oil," "gas" or "oil and gas".
4. For the above identified hydraulically fractured oil well population, the EPA calculated the gas to oil ratio (GOR) by dividing the standard cubic feet (scf) of gas produced during the first month of production by the barrels (bbl) of petroleum liquid produced during the first month. The EPA then used the GOR to categorize the wells into oil and gas wells. Oil wells were defined to be those wells with a GOR of less than 100,000 scf/bbl. This threshold was chosen because it is consistent with the threshold used in the EPA National Emissions Inventory Oil and Gas Emission Estimation Tool and the threshold used in several states, including Texas<sup>14</sup> and New Mexico<sup>15</sup>.
5. Based on the calculated GOR for the wells identified above, the EPA eliminated from the

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<sup>13</sup> DrillingInfo is a private organization specializing in compiling primarily publically available oil and gas data, conducting statistical analysis, and providing analysis platforms for customers. The DrillingInfo database is particularly focused on historical oil and gas production data and drilling permit data.

<sup>14</sup> Available at

[http://info.sos.state.tx.us/pls/pub/readtac\\$ext.TacPage?sl=R&app=9&p\\_dir=&p\\_rloc=&p\\_tloc=&p\\_ploc=&pg=1&p\\_tac=&ti=16&pt=1&ch=3&rl=79](http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=79).

<sup>15</sup> Available at <http://164.64.110.239/nmac/parts/title19/19.015.0002.htm>.

evaluation wells with a GOR of less than 300 scf of gas per barrel produced.

6. The EPA then calculated the following average daily gas production values for each oil well;
  - Average daily gas production over the first month of operation by dividing the total gas production in the first month of operation by the average number of days in a month (30.42);
  - Average daily gas production over the first 6 months of operation by dividing the total gas production in the first six months of operation by the average number of days in 6 months (182.5); and
  - Average daily gas production over the first year of operation by dividing the total gas production in the first year of operation by the total days in one year (365).
7. The EPA assumed that the average daily gas production during the first month was representative of the daily potential emissions during a hydraulically fractured oil well completion. Therefore, the estimated gas production from a representative oil well completion was determined by taking the average of the average daily natural gas production during the first month of operation for each of the above identified oil wells (i.e., hydraulically fractured, and completed in 2012).
8. To determine the potential methane and VOC emissions for a representative oil well completion or recompletion, the EPA converted the average natural gas potential emissions per day to short tons of potential methane and VOC emissions. The conversion factors used are those developed for the NSPS and outlined in the memorandum titled "*Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking*", available in the docket.<sup>16</sup> Specifically, the EPA assumes natural gas is 46.71% methane by volume, the density of methane is 0.0208 tons per Mcf, and that there is 0.8374 lbs of VOC per pound of methane.

The EPA then calculated the potential VOC and methane emissions during a hydraulically fractured oil well flowback by multiplying potential methane and VOC emissions per day by the number of days in the average flowback event. The data sources referenced in the white papers noted a range of flowback duration from 1-10 days. Some of the values in the ranges were based on study observation and some based on assumptions. Comments on the oil well completion white paper supported a flowback duration on the low end of the range. Our analysis assumes an oil well flowback duration is toward the low end of that range, 3 days.

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<sup>16</sup> See footnote 3.

Table 3-2 presents the estimated potential (i.e., uncontrolled) emissions from a representative oil well completion or recompletion. The data sources in the white papers and comments received on the white papers showed a broad range of potential emission estimates (8 to around 200 tons methane per completion or workover) for hydraulically fractured oil well completions. Some of the values were developed using data on gas production and assumptions about flowback; others used measurement data. As described above, the estimates presented in the table below were developed using flowback characteristics and gas production data and include the effect of a GOR threshold of 300 that excludes oil wells with very little gas production. The estimates in the table below represent emissions from that population of wells, in the absence of controls. To calculate emissions to the atmosphere using these values, additional information on gas that is not emitted (e.g., through use of RECs or flaring) is needed.

**Table 3-2. Uncontrolled Emission Estimates from Representative Oil Well Completion or Recompletion**

	<b>Average Daily Production Natural Gas (Mcf/event)</b>	<b>Potential Emissions Methane<sup>a</sup> (tons/event)</b>	<b>Potential Emissions VOC<sup>b</sup> (tons/event)</b>
3-Day Completion or Recompletion Event	999	9.72	8.14

a. It is assumed methane comprises 46.732 percent by volume of natural gas. The factor used to convert methane from volume to weight is 0.0208 tons methane per thousand cubic feet (Mcf) of methane.<sup>17</sup>

b. Assumes 0.8374 lb. VOC/lb. methane.

### 3.3 Control Techniques

#### 3.3.1 Potential Control Techniques

The techniques that have been proven to reduce emissions from oil well completions and recompletions are the same as those that were evaluated for development of the 2012 NSPS for gas well completions and recompletions; specifically RECs and completion combustion. As with natural gas wells, the use of a REC not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. Completion combustion destroys the organic compounds. Based on our research as published in the oil completions white paper, these technologies have been found to be technically feasible for oil well completions and recompletions, and are in use in the industry to control emissions from oil wells. The EPA identified no other potential control options for oil well completions. For the sake of convenience, the description sections included below are from the 2012 NSPS TSD with limited edits. The

<sup>17</sup> U.S. EPA. Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010. Appendix B, Pgs. 87-89.

following sections describe the cost impact of these technologies with respect to oil well completions based on our current analysis of emissions.

### *3.3.2 Reduce Emission Completions and Recompletions*

#### *3.3.2.1 Description*

Reduced emission completions, also referred to as “green” completions, use specially designed equipment at the well site to capture and treat gas during well completion activities. This process prevents some natural gas from venting and results in additional revenues for producers from the sale or use of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.<sup>18</sup>

In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).<sup>19</sup> In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.
- Pressure of produced gas. During the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the gathering line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another potential

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<sup>18</sup> U.S. EPA Fact Sheet No. 703: Green Completions. OAR: Natural Gas Star Program. Washington, DC. September 2004.

<sup>19</sup> Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. API Meeting Minutes. July 2010.

compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or CO<sub>2</sub>, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

### *3.3.2.1 Emission Reduction Potential*

RECs are an effective emission reductions method for oil well completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 2.2. The emission reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on information presented in the white papers, this analysis assumes 90 percent of flowback gas can be recovered during a REC.<sup>20</sup> Any amount of gas that cannot be recovered can be directed to a combustion device in order to achieve a minimum 95 percent reduction in emissions.

### *3.3.2.2 Cost Impacts*

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs. The EPA received information and comment from multiple technical experts that the equipment necessary to perform a REC for an oil well completion is the same as that for a gas well completion.

Therefore, as was determined in the 2011 NSPS TSD<sup>21</sup>, the annual cost of performing a REC

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<sup>20</sup> Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. Percent of Emissions Recovered by Reduced Emission Completions. May 2011.

<sup>21</sup> See footnote 1.

was estimated to be \$12,735 for a representative well completion lasting 3 days<sup>22</sup>. For our analysis, the cost is adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator.<sup>23</sup> The resulting cost for performing a REC for a well completion or recompletion lasting 3 days is estimated to be \$13,459.

Monetary savings associated with additional gas captured to the sales line is estimated based on a natural gas price of \$4.00 per Mcf.<sup>24</sup> It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates to a total recovery of 899 Mcf of natural gas per completion or recompletion. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately \$3,597. When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net cost on the order of \$9,862 per completion.

RECs are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. The cost per ton of emissions reduced was then calculated in two ways, both of which reflect that REC is a multi-pollutant control measure (VOC and GHG (in the form of limitations on methane)). The first method, the single-pollutant method, allocates all of the costs to one pollutant and zero to the other. The second method, the multi-pollutant method, allocates costs among the pollutants that a given technology reduced. This proration was based on estimates of the percentage reduction expected for each pollutant.

Based on expected emission reductions from the use of a REC, the cost of control for methane is \$1,539 per ton and \$1,837 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other. The cost is \$769 per ton of methane and \$919 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

Because a REC accomplishes gas savings, the cost of control for methane is \$1,127 per ton and \$1,346 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the

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<sup>22</sup> This cost was based on state of the industry in 2006 and adjusted to 2008 US Dollars. For the 2012 NSPS the EPA determined a cost per day value, however, the 2012 NSPS applied this per day cost to a 7-day event duration. Here the EPA use the same cost per day and a 3-day event duration.

<sup>23</sup> Available at <http://research.stlouisfed.org/fred2/series/GDPDEF/>.

<sup>24</sup> When including the additional natural gas recovery in the cost analysis, the EPA assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be \$4.46/Mcf in 2020 and \$5.06/Mcf in 2025. The \$4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

other, and the monetary gas savings is considered. Likewise, the cost is \$564 per ton of methane and \$673 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. For the purposes of this analysis, the EPA also analyzed costs for the a REC combined with the cost of a combustion device as described below in section 2.3.3.1. For the combined REC and combustion scenario, the cost of control for methane is \$1,861 per ton and \$2,222 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero to the other. The cost is \$930 per ton of methane and \$1,111 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC).

When gas savings is considered, for the combined REC and combustion, the cost of control for methane is \$1,471 per ton and \$1,757 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other, and the monetary gas savings is considered. Likewise, the cost is \$736 per ton of methane and \$879 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

### *3.3.2.3 Secondary Impacts*

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., NO<sub>x</sub>, PM, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

### *3.3.3 Combustion Devices*

#### *3.3.3.1 Description*

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. Combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.<sup>25</sup> Combustion devices are used to control VOC in many industrial settings, since these devices can normally handle fluctuations in concentration, flow rate,

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<sup>25</sup> U.S. EPA. AP-42, Fifth Edition, Volume I, Chapter 13.5 Industrial Flares. OAQPS. 1991.



heating value, and inert species content.<sup>26</sup> Combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These devices can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead (i.e., a pit flare). The flow directed to a combustion device during a well completion may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. On the other end of the spectrum is the enclosed combustor that is specifically designed for completions that is an integral part of a completion equipment package. For the purpose of this analysis, the term combustion device represents any types of combustion devices used in the industry for control of hydrocarbon emissions.

### *3.3.3.2 Emission Reduction Potential*

It is difficult to measure precisely the destruction efficiency of a combustion device during a well completion activity. The actual destruction efficiency achieved in practice can be expected to vary with the amount of noncombustible gas and liquids in the gas flow. For the purposes of this analysis, a destruction efficiency of 95 percent, consistent with the expected destruction efficiency of a properly designed and operated flare, was assumed for completion combustion devices over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes the use of a continuous ignition source with an independent external fuel supply to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a completion combustion device or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences). As a result, the design and nature of combustion devices used for completions must handle multiphase flow and stream compositions well site conditions that vary during the flowback period and not all unrecoverable gas can be safely combusted in every case.

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<sup>26</sup> U.S. EPA. Air Pollution Control Technology Fact Sheet: FLARES. Clean Air Technology Center.

### 3.3.3.3 Cost Potential

An analysis estimating the cost for wells including combustion devices was conducted for the 2012 NSPS, resulting in an estimated average completion combustion device cost of approximately \$3,523 (2008 dollars).<sup>27</sup> For our analysis, this cost was adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator<sup>28</sup> resulting in an estimated annual cost of \$3,723 per well completion. As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimate. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost per ton of emissions reduced was then calculated in two ways. The first method (the single-pollutant approach) allocated all of the costs to one pollutant and zero cost to the other. The second method (the multi-pollutant approach) allocated costs among the pollutants that a given technology reduced (i.e., in this case GHG in the form of limitations on methane, and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. Completion combustion devices have a cost of control of \$403 per ton of methane or \$481 per ton of VOC for oil well completions and recompletions when 100 percent of the cost is attributed to one pollutant and zero to the other. Under the multipollutant approach where the cost is prorated to both pollutants equally (i.e., a 50 percent to methane and 50 percent to VOC), the cost of control is \$202 per ton of methane and \$241 per ton of VOC. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 3-3.

### 3.3.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including NO<sub>x</sub>, CO, sulfur oxides (SO<sub>x</sub>), CO<sub>2</sub>, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the

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<sup>27</sup> The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals the 2009 average value for the combustion device is \$3,195.

<sup>28</sup> Available at <http://research.stlouisfed.org/fred2/series/GDPDEF/>.

flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.<sup>29</sup> The high methane content of the gas stream routed to the completion combustion device suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.<sup>30</sup>

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.<sup>31</sup> These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided in Table 3-5.

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<sup>29</sup> See footnote 25.

<sup>30</sup> Ibid.

<sup>31</sup> Ibid.

**Table 3-3. Reduced Emission Completion and Combustion Emission Reductions and Cost Impacts Summary**

Control Technology	Emissions Reduced Per Completion <sup>a</sup> (short tons)		Volume of Whole Gas Captured (Mcf/completion)	Value of Whole Gas Captured (\$/completion)	Annual Cost (\$)	Cost of Control Per Completion (excluding gas savings) (\$/short ton)		Cost of Control Per Completion (including gas savings) (\$/short ton)	
	Methane	VOC				Methane	VOC	Methane	VOC
REC (100) <sup>b</sup>	8.75	7.33	899	\$3,597	\$13,459	\$1,539	\$1,837	\$1,127	\$1,346
REC (50/50) <sup>c</sup>	8.75	7.33	899	\$3,597	\$13,459	\$769	\$919	\$564	\$673
REC and Combustion device (100) <sup>b,d</sup>	9.23	7.73	899	\$3,597	\$17,183	\$1,861	\$2,222	\$1,471	\$1,757
REC and Combustion device (50/50) <sup>c,d</sup>	9.23	7.73	899	\$3,597	\$17,183	\$930	\$1,111	\$736	\$879
Completion Combustion (100) <sup>b</sup>	9.23	7.73	0	\$0	\$3,723	\$403	\$481	\$403	\$481
Completion Combustion (50/50) <sup>c</sup>	9.23	7.73	0	\$0	\$3,723	\$202	\$241	\$202	\$241

a. Assumes 95% control.

b. Scenario where 100 percent of the cost of control is attributed to methane and VOC.

c. Scenario where 50 percent of the cost of control is attributed to methane and 50 percent is attributed to VOC.

d. Control option that combines use of a REC and a combustion device to attain 95 percent control.

**Table 3-4. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1<sup>a</sup>**

<b>Pollutant</b>	<b>Emission Factor (lb/MMBtu)</b>
THC <sup>b</sup>	0.14
CO	0.31
NO <sub>x</sub>	0.068
PM <sup>c</sup>	0-274
<b>Pollutant</b>	<b>Emission Factor (kg CO<sub>2</sub>/MMBtu)</b>
CO <sub>2</sub> <sup>d</sup>	60

a. Based on combustion efficiency of 98 percent.

b. Measured as methane-equivalent.

c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.

d. Carbon dioxide factor is derived from the CO<sub>2</sub> emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

### 3.4 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO<sub>x</sub>, and particulate matter (PM) from the combustion of the completion gases in the completion combustion device. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1. Require combustion for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 2. Require REC for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 3. Require REC and combustion for hydraulically fractured oil well completions and recompletions where gas can be recovered with REC; and
- Regulatory Option 4. Require combustion where gas cannot be recovered with REC.

The following sections discuss these regulatory options.

#### 3.4.1 Evaluation of Regulatory Options

Under Regulatory Option 1, nearly all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., NO<sub>x</sub>, CO). Therefore, EPA rejected Regulatory

**Option 1.**

The second regulatory option would require RECs for all completions and recompletions of hydraulically fractured oil wells. As stated previously, RECs are not technically feasible for all well completions, such as exploratory wells due to their distance from sales lines. Further, RECs are also not always technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas or inert gas concentrations.

The third regulatory option consists of a combination of REC and combustion for hydraulically fractured oil well completions. As discussed for Regulatory Option 2, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure or inert gas concentrations. In order to allow for owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g., wellhead pressure or inert gas concentrations), or infrastructure issues (e.g., absence of pipelines or processes on-site which can be used to route captured gas) Regulatory Option 3 also allows for the use of a completion combustion device in combination with RECs.

Under this option, some venting must be allowed in lieu of combustion for situations in which combustion would present safety hazards, other concerns.

Regulatory Option 4 reduces emissions through combustion in situation where gas cannot be recovered through REC (for exploratory and delineation wells due to their distance from sales lines, low pressure wells).

## 4.0 FUGITIVE EMISSIONS STANDARDS

In the TSD for the proposed rule, monitoring options for reducing fugitive emissions from well sites and compressor stations were analyzed. The monitoring options that were analyzed included optical gas imaging (OGI) and Method 21 at monitoring frequencies of annual, semiannual and quarterly. For Method 21 repair thresholds of 10,000 ppm, 2,500 ppm and 500 ppm were also analyzed for each of the monitoring frequencies. Based on the analysis in the proposed rule TSD, the semiannual OGI monitoring option was selected as BSER for well sites and compressor stations. Comments on the proposed BSER analysis were received during the proposed rule comment period, and the BSER analysis for the OGI option was re-evaluated to take into account these comments. In response to comments, Method 21 was also re-evaluated as an alternative option for fugitive emission monitoring.

### 4.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as pressure release valves (PRVs), pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

For the purposes of the analysis and regulatory evaluation of fugitive emissions from components and equipment, the EPA differentiated between the current definition of "equipment" in the rule<sup>32</sup> and the intended definition for the purposes of addressing fugitive emissions. Therefore in the final rule, the EPA have defined a new term, "fugitive emissions component" as the focus of the

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<sup>32</sup> The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

requirements for fugitive emissions. The proposed definition for fugitive emissions component is as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a gas-driven pneumatic controller or a gas-driven pump, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from sites other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

The EPA received comment that this proposed fugitive emissions component definition was too broad and vague and may include equipment such as separators, pressure vessels, and dehydrators instead of the components (i.e., valves, connectors) on the equipment. The commenters also asserted that the "included but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Based on these comments, the EPA has revised the definition of fugitive emissions component in the final rule to read:

*Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*



In April of 2014, the EPA published a white paper<sup>33</sup> which summarized the EPA's current understanding of methane and VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities. The white paper also outlined the EPA's understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

## **4.2 Fugitive Emissions Data and Emissions Factors**

### *4.2.1 Model Plants*

For the proposed rule, model plants were developed to estimate fugitive emissions from well sites and compressor stations. Data from the 2016 draft GHG Inventory<sup>34</sup>, developed with the most recently published GHGRP reported data, were used to determine the equipment counts for well sites and compressor stations. Component counts per piece of equipment were those used in the GHG Inventory and GHGRP, which were derived the EPA/GRI study and 40 CFR, part 98, subpart W tables, were then used to determine the total number of fugitive components (valves, connectors, OELs, and PRVs) at each of these sites. A description of the data and methodology for determining fugitive emissions for these model plants are discussed in the following sections.

### *4.2.2 Oil and Gas Production Well Sites*

Oil and natural gas production practices and equipment vary from site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Baseline model plant emissions for the natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from GHG Inventory, derived from GHGRP, EPA/GRI,

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<sup>33</sup> U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf>.

<sup>34</sup> The draft 2016 GHG Inventory was the most recent data available at the time of this analysis. The 2016 GHG Inventory was finalized April 15, 2016 with the same data that was used in the public review draft. Therefore, this analysis is consistent with the most recent final GHG Inventory.

and 40 CFR part 98, subpart W tables as described above, and the component oil and natural gas production emission factors from AP-42<sup>35</sup>. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the emissions from the production segment (e.g., oil production well sites and natural gas production well sites) are presented in Table 4-1. The emission factors in Table 4-1 are also used to calculate fugitive emissions from gathering and boosting stations.

**Table 4-1. Oil and Gas Production Operations Average TOC Emissions Factors**

Component Type	Component Service	Emission Factor <sup>a</sup> (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

#### 4.2.2.1 Proposed Rule Well Site Model Plant

A model plant for natural gas and oil well sites was developed using the average number of wells associated with a well site using data from the DrillingInfo HPDI® database<sup>36</sup>. The analysis, described in the TSD for the proposed rule, determined that the national average of wells per well site was 1.81, and was rounded to 2.0 wells per well site for the model plant fugitive analysis for both natural gas production and oil production well sites.

For the proposed rule, average equipment count per well data from the EPA/GRI document for natural gas production well sites and GHG Inventory for oil production well sites were used to determine the number of production equipment located at a well site. The average equipment count per well for each of the equipment types were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer.

The types of production equipment located at a natural gas well site includes: gas wellheads, separators, meters/piping, in-line heaters, and dehydrators. The types of components that are associated

<sup>35</sup> U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

<sup>36</sup> Drilling Information, Inc. 2011. *DI Desktop*. 2011 Production Information Database.

with this production equipment include: valves, connectors, OELs, and PRVs. Component counts for each of the production equipment items were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer.

Baseline fugitive emissions for the proposed rule were calculated using the estimated component counts for the natural gas well site and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS<sup>37</sup>. For the proposed rule, the fugitive emissions for the natural gas production well site model plant were determined to be 4.54 tons per year of methane and 1.26 tons per year of VOC.

For oil well sites, data from the GHG Inventory, derived from GHGRP reported data, were used to estimate equipment counts for these sources. The types of oil well site equipment include: oil well heads, separators, headers and heater/treaters. Fugitive emissions components counts for these equipment types were estimated using component count data from Table W-1C of 40 CFR part 98, subpart W.

The estimated baseline fugitive emissions from oil well sites were calculated using the estimated component counts and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. For the proposed rule, the fugitive emissions for the oil well site model plant were determined to be 1.09 tons per year of methane and 0.30 tons per year of VOC.

#### *4.2.2.2 Final Rule Natural Gas Well Site Model Plant*

During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016<sup>38</sup> GHG Inventory, and was used to revise the equipment

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<sup>37</sup> Memorandum to Bruce Moore. U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking". July 28, 2011.

<sup>38</sup> In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

counts for the natural gas well sites. The average equipment count per well was multiplied by the average number of wells per well site (2) and rounded to the next highest integer. The updated equipment counts per natural gas well site were 2 separators, 3 meters/piping, 1 in-line heaters, and 1 dehydrators per well. In comparison to the model plant in the proposed rule TSD, the only change in equipment counts was for meters/piping which increased from 1 to 3. Average component counts for each piece of equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for natural gas production well sites is presented in Table 4-2.

The baseline fugitive emissions for the natural gas well site model plant were calculated using the revised component counts for the natural gas well site model plant and the oil and natural gas production AP-42 TOC emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the natural gas well site model plant were determined to be 5.50 tons per year of methane and 1.53 tons per year of VOC and are provided in Table 4-3.

#### *4.2.2.3 Final Rule Oil Well Site Model Plant*

Comments on the proposed rules stated that methane emissions from oil well site model plants were underestimated. While some oil wells produce very little natural gas (oil wells with a gas-to-oil-ratio less than 300 standard cubic feet of gas per stock barrel of oil), other oil wells produce significant volumes of natural gas (oil wells with a gas-to-oil-ratio greater than 300 standard cubic feet of gas per stock barrel of oil). To address these types of oil wells, two model plants were developed to estimate fugitive emissions from oil well sites. The oil well site model plant developed for the proposed rule was used to define the oils wells with a gas-to-oil ratio less than 300 standard cubic feet of gas per stock barrel of oil (< 300 GOR). During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016<sup>39</sup> GHG Inventory, and was used to revise

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<sup>39</sup> In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

the equipment counts for the oil well sites. The equipment count for this model plant consists of 2 oil wellheads, 1 separator, 1 header, and 1 heater/treater. To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (> 300 GOR), three meters/piping were added to the equipment counts included for the < 300 GOR model plant to account for the handling of the natural gas from the well. Component counts for the oil well equipment (wellhead, separator, header, heater/treater) were obtained from Table W-1C of subpart W. The component counts for meters/piping were obtained from the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per production equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for oil well site model plants are presented in Table 4-4.

Baseline model plant emissions for the oil well site model plants were calculated using the fugitive emissions component counts and the component oil and natural gas production emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the < 300 GOR model plant were determined to be 1.23 tons per year of methane and 0.33 tons per year of VOC. The fugitive emissions for the > 300 GOR model plant were determined to be 2.75 tons per year of methane and 0.75 tons per year of VOC. A summary of the emissions are provided in Table 4-5.

**Table 4-2. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant**

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Equipment <sup>a</sup>				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
Total						138.9	509.4	14.3	6.9
Rounded Total						139	510	15	7

a. Data Source: EPA/GRI, CH<sub>4</sub> Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

**Table 4-3. Estimated Fugitive Emission Estimate for Natural Gas Well Site Model Plant**

Natural Gas Well Site Model Plant Component	Model Plant Component Count <sup>a</sup>	Uncontrolled Emission Factor <sup>b</sup> (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane <sup>c</sup>	VOC <sup>d</sup>
Valves	139	0.0045	4.196	1.166
Connectors	510	0.0002	0.684	0.190
OELs	15	0.002	0.201	0.056
PRVs	7	0.0088	0.413	0.115
Total			5.50	1.53

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.

b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

c. Methane emissions calculated using 0.695 weight ratio for Methane/TOC obtained from gas composition memorandum.

d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

**Table 4-4. Average Fugitive Emissions Component Count for Oil Well Site Model Plant**

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment <sup>a</sup>					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR) <sup>a</sup>											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Total							29	54	42	0	2
Oil Well Model Plant (> 300 GOR) <sup>b</sup>											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
Total							68	54	186	2	4

a. Oil well (<300 GOR) component counts obtained from Table W-1C of 40 CFR part 98, subpart W.

b. Oil well (>300 GOR) component counts from 40 CFR Part 98, subpart W, Table W-1C.

**Table 4-5. Estimated Fugitive Emission Estimate for Oil Well Site Model Plant**

Oil Well Site Model Plant Component	Model Plant Component Count <sup>a</sup>	Uncontrolled Emission Factor <sup>b</sup> (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane <sup>c</sup>	VOC <sup>d</sup>
<i>Oil Well Model Plant (&lt; 300 GOR)</i>				
Valves	29	0.0045	0.876	0.243
Flanges	54	0.00039	0.185	0.039
Connectors	42	0.0002	0.056	0.016
OELs	0	0.002	0	0
PRVs	2	0.0088	0.118	0.033
Total			1.23	0.33
<i>Oil Well Model Plant (&gt; 300 GOR)</i>				
Valves	68	0.0045	2.053	0.571
Flanges	54	0.00039	0.185	0.039
Connectors	186	0.0002	0.250	0.069
OELs	2	0.002	0.027	0.007
PRVs	4	0.0088	0.236	0.066
Total			2.75	0.75

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.

b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

c. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.

d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

#### 4.2.3 Compressor Stations

The proposed rule TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (e.g., valves, connectors) that may be sources of fugitive emissions associated with these operations.



*4.2.3.1 Proposed Rule Compressor Station Model Plant*

For the proposed rule TSD, baseline model plant emissions for compressor stations were calculated using the fugitive emissions component counts from the EPA/GRI document and the component oil and natural gas production emission factors from AP-42 for gathering and boosting stations and EPA/GRI emission factors for transmission and storage stations. Annual emissions were calculated assuming 8,760 hours of operation each year. The AP-42 emission factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the new source emissions from the gathering and boosting stations are presented in Table 4-1. In the proposed rule TSD, the fugitive emissions from gathering and boosting stations were estimated to be 35.1 tons per year of methane and 9.77 tons per year of VOC. The model plant fugitive emissions for transmission stations were estimated to be 62.4 tons per year of methane and 1.73 tons per year of VOC, and 164.4 tons per year of methane and 4.55 tons per year of VOC for storage stations.

*4.2.3.2 Final Rule Compressor Station Model Plant*

Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct them to the natural gas processing plants. These stations have similar production equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators and other equipment) to well sites; however, they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressor seals are addressed in Chapter 8 of this document. A summary of the fugitive emissions component counts for oil and gas gathering and boosting stations are presented in Table 4-6.

The proposed gathering and boosting model plant did not change from proposal. Therefore, the baseline emissions that are discussed in Section 4.2.3.1 remain the same for the final TSD and are summarized in Table 4-7. The emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

#### *4.2.3.3 Final Rule Natural Gas Transmission and Storage Model Plant*

Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. The segments include fugitive emissions from components related to inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. The blowdown open-ended lines were included in the proposed rule TSD, but were determined, based on comments, to be a vent rather than a fugitive emission source. Therefore in this analysis, emissions from blowdown open-ended lines were removed from the component list and the associated emissions were not included in the total fugitive emissions from transmission and storage stations. For the other components at these facilities, fugitive emissions component counts and methane emission factors were obtained from the EPA/GRI study. A summary of the fugitive emissions component counts, component emission factors and baseline methane and VOC emissions for transmission and storage model plants are presented in Table 4-8. The average fugitive emissions for transmission stations were determined to be 40.4 tons per year of methane and 1.12 tons per year of VOC and 142.4 tons per year of methane and 3.94 tons per year of VOC for storage facilities. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

**Table 4-6. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plant**

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment <sup>a</sup>				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
Total						906	2,864	83	48
Rounded Total						906	2,864	83	48

a. Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

**Table 4-7. Estimated Fugitive Emissions for Gathering and Boosting Station Model Plant**

Gathering and Boosting Station Model Plant Component	Model Plant Component Count	Uncontrolled Emission Factor <sup>a</sup> (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane <sup>b</sup>	VOC <sup>c</sup>
Valves	906	0.0045	27.35	7.603
Connectors	2,864	0.0002	3.84	1.068
OELs	83	0.002	1.11	0.310
PRVs	48	0.0088	2.83	0.788
Total			35.1	9.77

a. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

b. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.

c. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

**Table 4-8. Estimated Fugitive Emissions for Natural Gas Transmission and Storage Model Plant**

Component	Model Plant Component Count <sup>a</sup>	Component Methane Emission Factor <sup>a</sup> (Mscf/year/component)	Methane Emissions <sup>b</sup> (tpy)	VOC Emissions <sup>c</sup> (tpy)
<b>Transmission Facility</b>				
Valve	673	0.867	12.1	0.336
Control Valve	31	8	5.2	0.143
Connectors	3,068	0.147	9.4	0.260
OEL	51	11.2	11.9	0.329
PRV	14	6.2	1.8	0.050
Total			40.4	1.12
<b>Storage Facility</b>				
Valve	1,868	0.867	33.7	0.933
Connector	5,571	0.147	17.0	0.472
OEL	353	11.2	82.3	2.77
PRV	66	6.2	8.52	0.236
Valve (Inj/With)	30	0.918	0.57	0.016
Connector (Inj/With)	89	0.125	0.23	0.006
OEL (Inj/With)	7	0.237	0.03	0.001
PRV (Inj/With)	1	1.464	0.03	0.001
Total			142.4	3.94

a. Component counts and methane emission factors for non-compressor related components obtained from EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

b. Methane emissions calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.

c. VOC emissions calculated using 0.0277 weight ratio for VOC/methane obtained from Gas Composition memorandum.

## 4.3 Control Techniques

### 4.3.1 Potential Control Techniques

The use of OGI and Method 21 to monitor and reduce fugitive emissions from well sites and compressor stations was evaluated in the TSD for the proposed rule. Based on this analysis, it was determined that semiannual monitoring using OGI was BSER for both well sites and compressor stations. The EPA received numerous comments on this BSER determination and re-evaluated the OGI option using updated information received during the comment period. The re-evaluation for the final rule is provided in the following sections.

#### *4.3.2 Fugitive Emissions Detection and Repair with OGI*

##### *4.3.2.1 Description*

The reduction of fugitive emissions from well sites and compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. Under this option, the final rule states that monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA needed to estimate the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI the operator would not be able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions would be required to be repaired. If a fugitive emissions component cannot be immediately repaired during the monitoring survey, the operator must repair or replace the component as soon as practicable, but no later than 30 days after detection of the fugitive emissions. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (e.g., a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

##### *4.3.2.2 Emission Reduction Potential*

Information in the white paper related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not

provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission<sup>40</sup> which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy ( $\geq 6$  to  $\leq 12$  tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy ( $> 12$  to  $\leq 50$  tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy ( $> 50$  tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on the information in the studies and EPA's engineering judgement, the potential emission reduction percentages for the proposed rule were estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies<sup>41</sup> were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500

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<sup>40</sup> Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9)*. February 7, 2014.

<sup>41</sup> Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program, April 25, 2016.

ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF<sup>42</sup> using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.<sup>43</sup>

#### *4.3.2.3 Cost Impacts*

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

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<sup>42</sup> ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016.

<sup>43</sup> See Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be \$57.80 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of \$231.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of \$3,468.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for annual monitoring was estimated to be \$925 semiannual monitoring was estimated to be \$1,850 and quarterly monitoring \$3,699.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of \$58 for compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities). For companies that own and operate well sites, the cost notification of compliance status was estimated to be \$58 per well site for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.
- Cost of a Method 21 Monitoring Device of \$10,800.
- Costs for implementing a fugitive emission monitoring plan for a company defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:
  - Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of \$925 per monitoring event. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be \$42 per monitoring event.
  - The cost for OGI monitoring using an outside contractor was assumed to be \$600 for a well site and \$2,300 for a compressor station.<sup>44</sup>
  - Annual repair costs were estimated to be \$299 per monitoring event for well sites, \$3,436 per monitoring event for gathering and boosting stations, \$3,361 per monitoring event for transmission stations, and \$6,946 per monitoring event for storage facilities. These costs were estimated assuming that 1.18 percent of the components are found to leak<sup>45</sup> during monitoring and 75 percent are repaired online and 25 percent are repaired offline.

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<sup>44</sup> Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

<sup>45</sup> The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (e.g., pumps LL, valve LL, agitators LL). There is no information



- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of \$58 per hour. This assumes the company is able to perform the resurvey without retaining contractors. The capital costs include the cost of Method 21 instrumentation (estimated to be \$10,800<sup>46</sup>). For compressor stations, the cost to resurvey repaired components was estimated to be \$2.00 per component.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, notification of initial compliance status, and purchase of a Method 21 instrumentation. The total capital cost of these activities was calculated to be \$17,620 per company defined areas for semiannual monitoring and \$19,470 per company define areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company defined area<sup>47</sup>, the capital cost per well site was estimated to be \$759 for annual monitoring, \$801 for semiannual monitoring and \$885 for quarterly monitoring. For compressor stations (gathering and boosting stations, transmission stations and storage facilities) the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation was calculated to be \$16,407 per facility. For gathering and boosting stations, this capital cost was assumed to be shared with other gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated 7 gathering and boosting stations, and the capital cost of each of these stations was estimated to be \$2,393.

For all oil and natural gas segments, the annual cost includes; subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and

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on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

<sup>46</sup> Average of subsequent monitoring costs in Table 13 from the Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180

<sup>47</sup> The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, semiannual and quarterly OGI surveys. The OGI monitoring cost memorandum<sup>48</sup> present the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant approach) that a given technology reduced (i.e., GHG (in the form of limiting methane emissions) and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 4-9, 4-10 and 4-11 presents a summary of the cost of control for methane and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method. Tables 4-12, 4-13 and 4-14 present a summary of the capital and annual costs, and the cost of control for methane and VOC using the multi-pollutant method (i.e., 50 percent of the cost attributed to methane and 50 percent of the cost attributed to VOC).

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<sup>48</sup> Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA, Evaluation of Cost methodologies for OGI Monitoring, April 6, 2016.

#### *4.3.2.4 Secondary Impacts*

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors<sup>49</sup> and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO<sub>x</sub>). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO<sub>x</sub>.

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<sup>49</sup> AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. <https://www3.epa.gov/otaq/ap42.htm#highway>

**Table 4-9. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option – Single Pollutant<sup>50</sup>**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Well Site <sup>d</sup>	2.20	0.61	\$759	\$1,318	\$809	\$600	\$2,158	\$368	\$1,324
Oil Well Site (GOR < 300) <sup>d</sup>	0.49	0.13	\$759	\$1,318	\$1,204	\$2,670	\$9,953	\$2,438	\$9,089
Oil Well Site (GOR > 300 GOR) <sup>d</sup>	1.10	0.30	\$759	\$1,318	\$1,063	\$1,198	\$4,380	\$967	\$3,533
Well Site Program Weighted Average <sup>h</sup>						<b>\$1,224</b>	<b>\$4,464</b>	<b>\$993</b>	<b>\$3,619</b>
Gathering & Boosting Station <sup>e</sup>	14.1	3.91	\$2,393	\$7,777	\$7,777	\$553	\$1,990	\$553	\$1,990
Transmission Station <sup>f</sup>	16.2	0.45	\$16,407	\$10,117	\$10,117	\$626	\$22,626	\$626	\$22,626
Storage Facility <sup>g</sup>	57.0	1.58	\$16,407	\$13,798	\$13,798	\$242	\$8,751	\$242	\$8,751
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$541</b>	<b>\$3,098</b>	<b>\$541</b>	<b>\$3,098</b>

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*

<sup>50</sup> As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

**Table 4-10. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option – Single Pollutant<sup>51</sup>**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Production Well Site <sup>d</sup>	3.3	0.917	\$801	\$2,285	\$1,521	\$693	\$2,494	\$461	\$1,660
Oil Well Sites (GOR < 300) <sup>d</sup>	0.74	0.199	\$801	\$2,285	\$2,114	\$3,085	\$11,503	\$2,854	\$10,639
Oil Well Site (GOR > 300 GOR) <sup>d</sup>	1.65	0.451	\$801	\$2,285	\$1,903	\$1,385	\$5,062	\$1,153	\$4,215
Well Site Program Weighted Average <sup>h</sup>						<b>\$1,415</b>	<b>\$5,160</b>	<b>\$1,183</b>	<b>\$4,314</b>
Gathering & Boosting Station <sup>e</sup>	21.1	5.86	\$2,393	\$13,534	\$13,534	\$642	\$2,309	\$642	\$2,309
Transmission Station <sup>f</sup>	24.2	0.67	\$16,407	\$15,868	\$15,868	\$655	\$23,659	\$655	\$23,659
Storage Facility <sup>g</sup>	85.5	2.37	\$16,407	\$23,230	\$23,230	\$272	\$9,822	\$272	\$9,822
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$625</b>	<b>\$3,480</b>	<b>\$625</b>	<b>\$3,480</b>

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$13,120 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$20,482 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*

<sup>51</sup> *Ibid.*

**Table 4-11. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant<sup>52</sup>**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Production Well Site <sup>d</sup>	4.4	1.222	\$885	\$4,220	\$3,201	\$960	\$3,453	\$728	\$2,619
Oil Well Sites (GOR < 300) <sup>d</sup>	0.99	0.265	\$885	\$4,220	\$3,991	\$4,272	\$15,929	\$4,041	\$15,064
Oil Well Site (GOR > 300 GOR) <sup>d</sup>	2.20	0.602	\$885	\$4,220	\$3,710	\$1,918	\$7,010	\$1,686	\$6,163
Well Site Program Weighted Average <sup>h</sup>						<b>\$1,960</b>	<b>\$7,145</b>	<b>\$1,728</b>	<b>\$6,299</b>
Gathering & Boosting Station <sup>e</sup>	28.1	7.81	\$2,393	\$25,049	\$25,049	\$891	\$3,205	\$891	\$3,205
Transmission Station <sup>f</sup>	32.3	0.89	\$16,407	\$27,369	\$27,369	\$847	\$30,606	\$847	\$30,606
Storage Facility <sup>g</sup>	114.0	3.15	\$16,407	\$42,093	\$42,093	\$369	\$13,348	\$369	\$13,348
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$864</b>	<b>\$4,732</b>	<b>\$864</b>	<b>\$4,732</b>

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$24,622 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$39,345 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*

<sup>52</sup> Ibid.

**Table 4-12. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Multi-Pollutant Method**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Production Well Site <sup>d</sup>	2.20	0.61	\$759	\$1,318	\$809	\$300	\$1,079	\$184	\$662
Oil Well Sites (GOR < 300) <sup>d</sup>	0.49	0.13	\$759	\$1,318	\$1,204	\$1,335	\$4,977	\$1,219	\$4,545
Oil Well Site (GOR > 300 GOR) <sup>d</sup>	1.10	0.30	\$759	\$1,318	\$1,063	\$599	\$2,190	\$483	\$1,767
Well Site Program Weighted Average <sup>h</sup>						<b>\$612</b>	<b>\$2,232</b>	<b>\$496</b>	<b>\$1,810</b>
Gathering & Boosting Station <sup>e</sup>	14.1	3.91	\$2,393	\$7,777	\$7,777	\$277	\$995	\$277	\$995
Transmission Station <sup>f</sup>	16.2	0.45	\$16,407	\$10,117	\$10,117	\$313	\$11,313	\$313	\$11,313
Storage Facility <sup>g</sup>	57.0	1.58	\$16,407	\$13,798	\$13,798	\$121	\$4,375	\$121	\$4,375
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$271</b>	<b>\$1,549</b>	<b>\$271</b>	<b>\$1,549</b>

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$16,696 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$1,191 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$7,376 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$7,369 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$11,050 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*

**Table 4-13. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option - Multi-Pollutant Method**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with saving) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Production Well Site <sup>d</sup>	3.3	0.917	\$801	\$2,285	\$1,521	\$347	\$1,247	\$231	\$830
Oil Well Sites (GOR < 300) <sup>d</sup>	0.74	0.199	\$801	\$2,285	\$2,114	\$1,543	\$5,752	\$1,427	\$5,319
Oil Well Site (GOR > 300 GOR) <sup>d</sup>	1.65	0.451	\$801	\$2,285	\$1,903	\$693	\$2,531	\$577	\$2,108
Well Site Program Weighted Average <sup>h</sup>						<b>\$708</b>	<b>\$2,580</b>	<b>\$592</b>	<b>\$2,157</b>
Gathering & Boosting Station <sup>e</sup>	21.1	5.86	\$2,393	\$13,534	\$13,534	\$321	\$1,155	\$321	\$1,155
Transmission Station <sup>f</sup>	24.2	0.67	\$16,407	\$15,868	\$15,868	\$327	\$11,829	\$327	\$11,829
Storage Facility <sup>g</sup>	85.5	2.37	\$16,407	\$23,230	\$23,230	\$136	\$4,911	\$136	\$4,911
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$312</b>	<b>\$1,740</b>	<b>\$312</b>	<b>\$1,740</b>

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$17,620 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$13,120 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$20,482 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*



**Table 4-14. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option - Multi-Pollutant Method**

Model Plant	Annual Emission Reductions <sup>a</sup> (tpy)		Capital Cost <sup>b</sup> (\$)	Annual Cost (\$/year)		Cost of Control (without savings) (\$/ton)		Cost of Control (with savings) <sup>c</sup> (\$/ton)	
	CH <sub>4</sub>	VOC		without savings	with savings	CH <sub>4</sub>	VOC	CH <sub>4</sub>	VOC
Natural Gas Production Well Sites <sup>d</sup>	4.40	1.222	\$885	\$4,220	\$3,201	\$480	\$1,726	\$364	\$1,310
Oil Well Sites (GOR < 300) <sup>d</sup>	0.99	0.265	\$885	\$4,220	\$3,991	\$2,136	\$7,964	\$2,020	\$7,532
Oil Well Sites (GOR > 300 GOR) <sup>d</sup>	2.20	0.602	\$885	\$4,220	\$3,710	\$959	\$3,505	\$843	\$3,081
Well Site Program Weighted Average <sup>h</sup>						<b>\$980</b>	<b>\$3,572</b>	<b>\$864</b>	<b>\$3,150</b>
Gathering & Boosting Station <sup>e</sup>	28.1	7.8	\$2,393	\$25,049	\$25,049	\$445	\$1,603	\$445	\$1,603
Transmission Station <sup>f</sup>	32.3	0.9	\$16,407	\$27,369	\$27,369	\$424	\$15,303	\$424	\$15,303
Storage Facility <sup>g</sup>	114.0	3.2	\$16,407	\$42,093	\$42,093	\$185	\$6,674	\$185	\$6,674
Compressor Stations Program Weighted Average <sup>h</sup>						<b>\$432</b>	<b>\$2,366</b>	<b>\$432</b>	<b>\$2,366</b>

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.

b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be \$16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of \$16,407.

c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

d. Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7% interest.

e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7% interest.

f. Annual cost for transmission station includes annual monitoring and repair cost of \$24,622 and amortization of the capital cost over 8 years at 7% interest.

g. Annual cost for storage facilities includes annual monitoring and repair cost of \$39,345 and amortization of the capital cost over 8 years at 7% interest.

h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

*Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.*

## 4.4 Regulatory Options

Monitoring of fugitive emissions was evaluated using OGI and Method 21 in the TSD for the proposed rule. For OGI, monitoring frequencies of annual, semiannual and quarterly were evaluated for well sites and compressor stations. Annual, semiannual and quartering monitoring was also evaluated for Method 21 at three different leak definitions; 500 ppm, 2,500 ppm and 10,000 ppm. Based on the results of these evaluations, semiannual monitoring using OGI was selected as BSER for well sites and compressor stations.

For this analysis, the OGI monitoring options were updated for the final rule using information received since proposal for the proposed rule. The OGI monitoring options include;

- Regulatory Option 1 – The implementation of an annual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 2 – The implementation of a semiannual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 3 – The implementation of a quarterly OGI fugitive emissions monitoring and repair program.

### 4.4.1 OGI Monitoring Options

As noted above, the EPA calculated a weighted average cost of control for well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 4-15.

**Table 4-15. Summary of the Cost of Control for the OGI Monitoring Options<sup>53</sup>**

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant (\$/ton)		Multi-Pollutant (\$/ton)		Single-Pollutant (\$/ton)		Multi-Pollutant (\$/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
<b>Well Sites</b>								
1 - Annual	\$1,224	\$4,464	\$612	\$2,232	\$993	\$3,619	\$496	\$1,810
2 - Semiannual	\$1,415	\$5,160	\$708	\$2,580	\$1,183	\$4,314	\$592	\$2,157
3 - Quarterly	\$1,960	\$7,145	\$980	\$3,572	\$1,728	\$6,299	\$864	\$3,150
<b>Compressor Stations</b>								
1 - Annual	\$504	\$2,225	\$252	\$1,112	\$272	\$1,201	\$136	\$601
2 - Semiannual	\$580	\$2,562	\$290	\$1,281	\$396	\$1,749	\$198	\$875
3 - Quarterly	\$802	\$3,540	\$401	\$1,770	\$618	\$2,728	\$309	\$1,364

#### 4.4.2 EPA Method 21 as an Alternative to OGI Monitoring

##### 4.4.2.1 Description

As an alternative to OGI monitoring, the EPA evaluated allowing the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations to determine if the emissions reductions were equal to or greater than the emissions reductions achieved using OGI monitoring. As with OGI monitoring, emissions reductions vary based on the frequency of the monitoring of the components as well as the repair threshold. Based on comments received on the proposed rule, the EPA evaluated repair thresholds of 500 ppm and 10,000 for Method 21 fugitive emissions monitoring.

##### 4.4.2.2 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair

<sup>53</sup> *Ibid.*

components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 4-16 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1) and solving for leak fraction. The initial leak frequencies can also be extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 4-16.

Using the parameters in Table 4-16, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 4-17.

**Table 4-16. Parameters and Assumptions Used to Calculate Monitoring Cycles**

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	$ALR = 0.044 * LF + 0.000017$	$ALR = 0.078 * LF + 0.00013$

**Table 4-17. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair**

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Annual	42	68	40
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 4-17 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 4-9 through 4-14), Table 4-18 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 parts per million leak thresholds. For annual monitoring, both the Method 21 leak thresholds had higher emission reductions than the OGI monitoring option. Only the 500 parts per million leak threshold had emission reductions that were equal to or greater than the OGI monitoring option for semiannual and quarterly monitoring.

**Table 4-18. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair**

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy) <sup>a</sup>		Method 21 500 ppm (tpy) <sup>a</sup>	
	Methane	VOC	Methane	VOC	Methane	VOC
<b>Annual Monitoring</b>						
Gas Well Sites	2.20	0.61	2.32	0.65	3.75	1.04
Oil Well Sites (GOR < 300)	0.49	0.13	0.52	0.14	0.84	0.23
Oil Well Sites (GOR > 300)	1.10	0.30	1.16	0.32	1.88	0.51
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
<b>Semiannual Monitoring</b>						
Gas Well Sites	3.30	0.92	3.01	0.84	4.14	1.15
Oil Well Sites (GOR < 300)	0.74	0.20	0.68	0.18	0.93	0.25
Oil Well Sites (GOR > 300)	1.65	0.45	1.51	0.41	2.07	0.57
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
<b>Quarterly Monitoring</b>						
Gas Well Sites	4.40	1.22	3.70	1.03	4.53	1.26
Oil Well Sites (GOR < 300)	0.99	0.26	0.83	0.22	1.02	0.27
Oil Well Sites (GOR > 300)	2.20	0.60	1.85	0.51	2.27	0.62
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.3	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 4-5 and 4-8 and percent reduction shown in Table 4-21.

## 5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves.

The 2012 NSPS promulgated requirements for control of emissions from pneumatic controllers in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD.

This chapter describes pneumatic controllers in the transmission and storage segment, including their function and associated emissions. Options available to reduce emissions from pneumatic controllers in the transmission and storage segment are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic controllers.

### 5.1 Process Description

#### 5.1.1 *Pneumatic Controllers*

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the transmission and storage segment, an estimated 84,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.<sup>54</sup>

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to

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<sup>54</sup> U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.

operate or control a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized that “closed loop” systems are applicable only in instances with very low pressure<sup>55</sup> and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller’s bleed stream. Since actuation emissions serve the controller’s functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions.<sup>56</sup> For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because intermittent controllers are inherently low emitting sources and the total emissions are dependent on the applications in which they are used, the EPA did not include intermittent controllers in this analysis. This is consistent with the treatment of these controllers under the 2012 NSPS.

In addition, not all pneumatic controllers are gas driven. At sites with electrical service sufficient

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<sup>55</sup> Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. Meeting Minutes from EPA Meeting with the API. October 2011.

<sup>56</sup> The EPA received comments indicating that in some cases intermittent controllers had continuous emissions, and low-bleed pneumatic controllers were observed to have emission rates that were 270 percent higher than the EPA’s emission factor for these devices, in some cases approaching the emission rate of high-bleed controllers. The EPA believes this is the result of malfunctioning controllers. The data the EPA have does not indicate that emissions from intermittent controllers are significant under normal operating conditions. The EPA are continuing to research this issue; however, the EPA do not believe additional requirements are warranted for such controllers based on the incidental, non-standard operation observed during these studies.



to power an instrument air compressor electrically powered pneumatic devices can be used. In addition, it may be possible to use electrically powered pneumatic devices at sites with electrical service. These “non-gas driven” pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not gas driven, they do not directly release natural gas. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas source category likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.<sup>57</sup>

## 5.2 Emissions Data and Information

### 5.2.1 Summary of Major Studies and Emission

In the evaluation of the emissions from pneumatic controllers in the transmission and storage segment and the potential options available to reduce the emissions, the EPA consulted numerous studies and sources of information. Table 5-1 presents these studies and sources of information with an indication of the type of relevant information contained in each resource.

**Table 5-1. Major Studies and Sources of Information Reviewed for Emissions and Activity Data**

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule and Technical Supporting Document <sup>a</sup>	EPA	2014	Nationwide	X	
Draft Inventory of GHG Emissions and Sinks: 1990-2014 <sup>b</sup>	EPA	2016	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry <sup>c</sup>	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) <sup>d</sup>	EPA	1996	Nationwide	X	

<sup>57</sup> Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Methane Emissions from the Petroleum Industry <sup>e</sup>	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States <sup>f</sup>	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program <sup>g</sup>	EPA	2000-2010	Other	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the U.S. <sup>h</sup>	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia <sup>i</sup>	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas <sup>j</sup>	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries <sup>k</sup>	ICF International	2014	Nationwide	X	X

a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.

b. U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.

c. Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the GRI and EPA. EPA-600/R-96-080c. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the GRI and EPA. EPA-600/R-96-080e. June 1996, and Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.

d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.

e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.

f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.

g. U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.

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

i. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.

j. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.

k. Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

### 5.2.2 Representative Pneumatic Device Emissions

Continuous bleed pneumatic controllers can be classified into two types based on their emission rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.<sup>58</sup>

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the GHG Reporting rule<sup>59</sup>, the Inventory of GHG Emissions and Sinks, new studies, as well as pneumatic controller vendor information obtained during the development of the NSPS rulemaking. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold. Since publication of the white paper, additional data have become available on emissions from pneumatic controllers, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015, and Allen et al. 2014. GHGRP reported methane emissions for 2014 are 197,387 tons CO<sub>2</sub> Eq.in transmission, and 111,354 tons CO<sub>2</sub> Eq.in storage. The 2016 GHG Inventory, with emissions data for 1990-2014, calculates that national methane emissions for pneumatic controllers are 694,801 tons CO<sub>2</sub>Eq. in transmission and 734,112 tons CO<sub>2</sub>Eq. in storage. In the Subramanian et al. 2015 data set, the average emission rate for pneumatic controllers in the transmission segment was 12.9 scfh, and the average emission rate for pneumatic controllers in the storage segment was 21.2 scfh. Information was not available on the fraction of high bleed versus low and intermittent bleed controllers in each population.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have

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<sup>58</sup> The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the GRI in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

<sup>59</sup> Available at <http://www.epa.gov/ghgreporting/reporters/subpart/w.html>.

emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.<sup>60,61</sup> While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. For this analysis, the EPA determined that best available emissions rate estimates for pneumatic controllers are presented in Table W-3 of the GHG Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W).

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from the average pneumatic controller type in the transmission and storage segment then estimate methane and VOC using a representative gas composition.<sup>62</sup>

The specific ratios from the representative gas composition were 0.908 lbs of methane per pound of natural gas and 0.0277 lbs VOC per pound methane. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

**Table 5-2. Average Bleed Emission Estimates per Pneumatic Controller in the Natural Gas Transmission and Storage Segment<sup>a, b</sup>**

High-Bleed (tpy)		Low-Bleed (tpy)	
Methane	VOC	Methane	VOC
3.013	0.083	0.227	0.00628

a. The conversion factor used in this analysis is 1,000 cubic feet (Mcf) of methane is equal to 0.0208 tons methane.

b. Natural gas transmission and storage emission factors for continuous bleed controllers were derived from Table W-1A of Subpart W.

### 5.3 Control Techniques

Several options to reduce emissions from pneumatic controllers were identified. Table 5-3 provides a summary of these options for reducing emissions from pneumatic controllers including: instrument air, non-gas driven controls, and enhanced maintenance. The use of instrument air systems, as discussed in the 2012 NSPS TSD<sup>63</sup>, requires a constant source of electric power. Because electric power is not necessarily available at all transmission and storage affected facilities, the use of instrument air systems would not be practically feasible as a control for emissions from pneumatic controllers in this

<sup>60</sup> U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.

<sup>61</sup> All rates are listed at an assumed supply gas pressure of 20 psig.

<sup>62</sup> See footnote 3.

<sup>63</sup> See footnote 2.

industry segment. Likewise, because the mechanical systems identified for use in this industry would require, at minimum, a backup source of electric power, this option is also not considered to be practically feasible for use in controlling these pneumatic controller emissions. The enhanced maintenance option is considered to be too variable and costly as a viable option for control pneumatic controller emissions. Based on these concerns, further analyses of these options were not conducted.

Given the various applicability, cost of emission reductions and cost issues with the control options, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic controllers. This conclusion is consistent with and supported by requirements of States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed controllers are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis.

As noted above, intermittent controllers are assumed to have zero bleed emissions. In addition, these controllers are assumed to not always be used in the same functional application as continuous bleed controllers. Therefore, intermittent controllers are not an appropriate option for control for all continuous bleed controllers. It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed.

**Table 5-3. Alternative Control Options for Pneumatic Controllers**

<b>Option</b>	<b>Description</b>	<b>Applicability/Effectiveness</b>	<b>Estimated Cost Range</b>
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around \$165 more than high bleed versions.
Convert to Instrument Air <sup>a</sup>	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. These systems can achieve 100 percent reduction in emissions. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back- up natural gas pneumatic device.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed Device <sup>b</sup>	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below \$1,000 to \$10,000 for entire systems.

<b>Option</b>	<b>Description</b>	<b>Applicability/Effectiveness</b>	<b>Estimated Cost Range</b>
Enhanced Maintenance <sup>c</sup>	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or lose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

a. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.

b. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.

c. CETAC-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

### 5.3.1 Low-Bleed Controller Emission Reduction Potential

As discussed in the above sections, low-bleed controllers provide the same operational function as high-bleed controllers, but have lower continuous bleed emissions. As summarized in Table 5-4, the average achievable reduction in emissions per controller is estimated to be approximately 2.79 tons of methane and 0.077 tons of VOC. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device currently available on the market.

**Table 5-4. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Controller with a Representative Low-Bleed Pneumatic Controller in the Natural Gas Transmission and Storage Segment**

<b>Baseline Emission reductions - High-Bleed Replaced with Low-Bleed<sup>a</sup></b> <b>(tpy)</b>	
<b>Methane</b>	<b>VOC</b>
2.79	0.077

a. Average emission reductions based on the typical emission rate from high-bleed and low-bleed controllers as listed in Table 5-2.

### 5.3.2 Emission Reduction Potential

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the transmission and storage segment.<sup>64</sup> This corresponds to 96 new high-bleed devices in the production segment (out of 120) that can be replaced with a new low-bleed alternative.

Applicability may depend on the function of instrumentation for an individual device such as whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and

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<sup>64</sup> See footnote 54.



precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

### 5.3.3 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.<sup>65</sup> As Table 5-5 indicates, the average cost for a low bleed pneumatic is \$2,471, while the average cost for a high bleed is \$2,698.<sup>66</sup> Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of \$227 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was annualized for a 15-year period using a 7 percent interest rate. This equated to an annualized cost of around \$25 per low-bleed controller.

**Table 5-5. Cost Projections for Representative Pneumatic Controllers<sup>a</sup>**

Controller Type	Minimum Cost (\$)	Maximum Cost (\$)	Average Cost (\$)	Low-Bleed Incremental Cost (\$)
High-Bleed Controller	\$387	\$7,398	\$2,471	\$227
Low-Bleed Controller	\$554	\$9,356	\$2,698	

a. Cost data from the 2012 NSPS was converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator. During the development of the 2012 NSPS major pneumatic controller vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

Although monetary savings associated with additional gas captured exist, these savings were not estimated for the transmission and storage segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. The cost per ton of emissions reduced was then calculated in two ways. The first method, the single pollutant approach, allocated all of the costs to one pollutant and zero to the other(s). The second method, the multipollutant approach, prorated costs among the pollutants that a given technology reduced (in this case GHG in the form of limiting methane emissions, and VOC). This proration was based on estimates of the percentage reduction expected for

<sup>65</sup> Ibid.

<sup>66</sup> Costs are estimated in 2012 U.S. Dollars.

each pollutant. Table 5-6 provides a summary of low-bleed pneumatic cost of control.

**Table 5-6. Cost-of Control for Low-Bleed Pneumatic Controllers versus High Bleed Pneumatics for the Transmission and Storage Segment<sup>67</sup>**

Method	Incremental Capital Cost Per Unit <sup>a</sup> (\$)	Total Annual Cost Per Unit <sup>b</sup> (\$/year)	Emission reductions (tpy)		Cost of Control (\$/ton)	
			Methane	VOC	Methane	VOC
Single Pollutant Approach 100%	\$227	\$25	2.79	0.077	\$9	\$323
Multipollutant Approach 50/50	\$227	\$25	2.79	0.077	\$4	\$162

a. Incremental cost of a low bleed controller versus a high bleed controller as summarized in Table 6-7.

b. Annualized cost assumes a 7 percent interest rate over a 15-year equipment lifetime.

#### 5.3.4 Secondary Impacts

Low-bleed pneumatic controllers are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes would be created, no wastewater generated, and no electricity required. Therefore, there are no secondary impacts expected from the use of low-bleed pneumatic devices.

## 5.4 Regulatory Options

EPA evaluated the following Regulatory alternatives for pneumatic controllers:

- Regulatory Option 1. Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2. Establish an emissions limit equal to 6 scfh.

#### 5.4.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely need to install instrument air systems to meet the threshold limit. Because facilities located in the transmission and storage segment might not always have sufficient electrical service to install an instrument air systems, this option would not be practically feasible in all situations. In addition, the cost of supplying electric power (which is highly variable) would need to be considered, which would likely render the cost of this control option unreasonable. Therefore, EPA rejected Regulatory Option 1 for facilities in the transmission and storage segment.

<sup>67</sup> As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the columns for the single pollutant approach present the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the transmission and storage segment. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria would be required to ensure the device function dictates the precision of a high bleed device. Therefore, EPA is utilizing Regulatory Option 2 for facilities in the transmission and storage segment.

## 6.0 PNEUMATIC PUMPS

The natural gas industry uses a variety of pneumatic gas-powered pumps where there is no reliable electrical power to “control processing problems and protect equipment”.<sup>68</sup> Pneumatic pumps are “small positive displacement, reciprocating units used throughout the oil and natural gas production sector to inject precise amounts of chemicals into process streams [or for freeze protection glycol circulation].”<sup>69</sup> Most chemical injection pumps (CIPs) fall into two main types: diaphragm, generally for heat tracing or plunger/piston, generally for chemical and methanol injection. This chapter describes pneumatic pumps including their function and associated emissions. Options available to reduce emissions from pneumatic pumps are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic pumps.

### 6.1 Process Description

In many situations across all segments of the oil and gas industry, pneumatic pumps make “use of gas pressure where electricity is not readily available.”<sup>70</sup> In the production segment, the supply gas is mostly produced natural gas, whereas in processing, the supply gas may be compressed air. In these gas-driven pneumatic pumps, characteristics that affect methane emissions include “the frequency of operation, the size of the unit, the supply gas pressure, and the inlet methane composition.”<sup>71</sup>

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps “recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.”<sup>72</sup> Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks. CIPs, i.e. piston/plunger pumps or small diaphragm pumps, inject small desired amounts of chemicals such as methanol to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

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<sup>68</sup> Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996.

<sup>69</sup> Ibid.

<sup>70</sup> Ibid.

<sup>71</sup> Ibid.

<sup>72</sup> U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. April 2014.

The piston and diaphragm pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.”<sup>73</sup>

Chemical injection pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged. This complete movement represents one full stroke.<sup>74</sup>

Typical chemicals injected in an oil or gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H<sub>2</sub>S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Since the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.<sup>75</sup>

Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.<sup>76</sup>

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<sup>73</sup> Ibid.

<sup>74</sup> Ibid.

<sup>75</sup> Ibid.

<sup>76</sup> GlobalSpec. Diaphragm Pumps Information. Available at [http://www.globalspec.com/learnmore/flow\\_transfer\\_control/pumps/diaphragm\\_pumps](http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps).

In addition, not all pneumatic pumps are gas-driven. These “non-natural-gas driven” pneumatic pumps can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not natural gas-driven, they do not directly release natural gas or VOC emissions. However, these systems have other energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power an air control system. This analysis assumed that natural gas processing plants and natural gas transmission stations are the only facilities in the oil and natural gas source category highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.<sup>77</sup> The application of electrical controls is further elaborated in Section 6.2.

#### 6.1.1 Emissions Data and Information

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each study.

**Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data**

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule	EPA	2012	Nationwide	X	
Inventory of U.S. GHG Emissions and Sinks: 1990-2014	EPA	2016	Nationwide/ Regional	X	
Methane emissions from the Natural Gas Industry	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry	EPA	1999	Nationwide	X	
Natural Gas STAR Program	EPA	2012	Study Specific	X	X

<sup>77</sup> Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.

### 6.1.1.1 Representative Pneumatic Pump Emissions

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic pumps<sup>78,79</sup>, Subpart W of the GHG Reporting rule<sup>80</sup>, U.S. GHG Natural Gas and Petroleum Inventories (GHG Inventory)<sup>81</sup>, and U.S. EPA GRI Report<sup>82</sup>. Subpart W and GHG Inventory use the emission factors from the U.S. EPA GRI Report. Similarly, EPA determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA GRI Report. For the activity factor, EPA determined the best available data is the GHG Inventory. Since publication of the white paper, additional data have become available on emissions from pumps, including GHGRP 2014 reporting year data. In 2014, reported methane emissions from chemical injection pumps in the production segment were 3,037,798 tons of CO<sub>2</sub> Eq. In the Inventory of Greenhouse Gas Emissions and Sinks: 1990-2014, national methane emissions from chemical injection pumps for 2014 are around 8,034,400 tons of CO<sub>2</sub>Eq.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in each industry segment and then estimate VOC and HAP using the gas composition as was determined for the NSPS.<sup>83</sup> The specific ratios from the gas composition used for this analysis were 0.278 lbs VOC per pound methane in the production and processing segments. Table 6-2 summarizes the estimated bleed emission factors for a representative pneumatic pump by industry segment.

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<sup>78</sup> U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.

<sup>79</sup> U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.

<sup>80</sup> U.S. Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases from Petroleum and Natural Gas Systems – Subpart W. Washington, DC. November 2010.

<sup>81</sup> U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2012. Available at <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html>.

<sup>82</sup> Gas Research Institute (GRI)/U.S. Environmental Protection Agency. Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m).

<sup>83</sup> See footnote 3.

**Table 6-2. Average Bleed Emission Estimates per Pneumatic Pump**

Segment/Pump Type	Emission Factor (scf/hr) <sup>a</sup>	Emission factor (Mcf/year) <sup>b</sup>	Emission Factor (tpy) <sup>c</sup>	Emission Factor (tpy) <sup>d</sup>
	Natural Gas	Methane	Methane	VOC
<i>Production</i>				
Diaphragm	22.45	163	3.46	0.96
Piston	2.48	18	0.38	0.11
<i>Processing</i>				
Small Diaphragm	22.45	163	3.46	0.96
Medium Diaphragm	22.45	163	3.46	0.96
Large Diaphragm	22.45	163	3.46	0.96
Small Piston	2.48	18	0.38	0.11
Medium Piston	2.48	18	0.38	0.11
Large Piston	2.48	18	0.38	0.11

a. Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R-96-080m), Sections 6.1 – Diaphragm Pumps and 6.2 – Piston Pumps. In the development of the emission factor, the GRI study incorporated a usage factor of 44% for diaphragm pumps and 40% for piston pumps.

b. Assumes 8760 hrs/yr and volumetric fraction of methane is 82.9% of natural gas in natural gas production and processing.

c. Assumes density of methane is 19.26 g/scf.

d. Assumes 0.27797 VOC content per pound of methane in natural gas production and processing.

## 6.2 Control Techniques

Gas-driven chemical pumps emit methane during normal operations. Depending on the type of pump, and the constraints of the location, companies can utilize a variety of technologies to reduce emissions. Table 6-3 provides a summary of these options for reducing emissions from gas-driven chemical pumps including: instrument air, solar, electricity, or routing emissions to a gas capture system or flare.

In situations where the replacement of gas-driven pumps with electric, solar and instrument air pumps is not possible, emissions can be captured via a vapor recovery unit (VRU), or sent to a combustion device. Emission control options for gas-driven pumps are described in the following section.



**Table 6-3. Alternative Control Options for Gas-Driven Pumps**

<b>Option</b>	<b>Description</b>	<b>Applicability/Effectiveness</b>	<b>Estimated Cost Range</b>
Convert to Solar Pumps	Solar power cells can generate electricity to power the pump. Solar cells can utilize a back-up power system to ensure reliability.	Solar powered pumps are only reliable in areas where the sun can power the pump reliably. These devices can result in 100 percent reduction in emissions where applicable.	Capital costs for converting to solar pumps is approximately \$2,300 per device
Convert to Electric Pumps	Electric pumps can be used where a reliable source of electricity is available at the facility.	Electric powered pumps are only reliable with a constant supply of electricity. Overall, this option is applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Capital costs range between \$1,807 to \$5,352 plus electricity costs and an average annual maintenance cost of \$263 per device.
Convert to Instrument Air <small>Error! Bookmark not defined.</small>	Instrument air systems can be used by replacing compressed air for the gas in pumps. These systems include a compressor, electrical power source, air dehydrator (depending on the type of pump), and volume tank.	Instrument air systems reduce emissions by 100 percent by replacing natural gas with instrument air. This technology offers economies of scale, where it is more economical at facilities with more pneumatic pumps. The system requires a reliable source of electrical power.	A complete cost analysis is provided in Section 6.3.3 System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Route Natural Gas to an Existing Control Device	Routing natural gas from a gas-driven pump entails piping to a control device inlet stream.	Routing natural gas pumps to a combustion device reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when a control device with available capacity is present on site.	Capital costs will vary depending on the distance of pipeline necessary, but are approximately \$5,433 per device.
Route Natural Gas to Newly Installed Control Device	Routing natural gas from a gas-driven pump to a control device requires installation of a control device and piping between the pump and the control device.	Routing natural gas-driven pumps to a combustion control device typically reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when utilities (i.e., electricity, water) needed to run the device are readily available.	Capital costs will be approximately \$48,500 with annual costs around \$104,000.
Route Natural Gas to Existing Gas Capture System	Routing natural gas from a gas-driven pump entails piping to a VRU.	Routing natural gas-driven pumps to a VRU reduces VOC and methane emissions through gas capture where emission reduction efficiencies are typically 95 percent. Routing natural gas	Capital costs will vary depending on the distance of pipeline necessary, but are estimated to be approximately \$5,433 per device.

Option	Description	Applicability/Effectiveness	Estimated Cost Range
		to a VRU is applicable when an existing VRU with available capacity is present on site.	
Route Natural Gas to Newly Installed Gas Capture System	Routing natural gas from a gas-driven pump to a gas capture system requires the installation of a gas capture system such as a VRU and piping between the pump and the capture system. There must also be an onsite use for the captured gas such as a combustion engine; otherwise, a control device would be required.	Installing a VRU and sending natural gas from pumps results in emission reductions of approximately 95percent. This option is most effective at facilities with a large number of pumps, and other emission sources that can also be sent to the VRU.	Capital costs will be approximately \$36,000 with annual costs around \$7,500.

## *6.2.1 Solar Pumps*

### *6.2.1.1 Emissions Reduction Potential*

Solar pumps provide the same functionality as gas-driven pumps, and can be utilized at remote sites where a reliable source of electricity is not available. Solar-charged direct current (DC) pumps can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 pounds per square inch gage (psig) and have zero natural gas emissions. Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions. Therefore, based on the emissions from Table 6-2 above, the EPA estimates converting natural gas-driven chemical pumps to solar-powered pumps can reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump for all segments. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year per piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

### *6.2.1.2 Effectiveness*

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Solar-powered pumps are typically low volume pumps that inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

### *6.2.1.3 Cost Impacts*

The primary costs associated with conversion to solar pumps are the initial capital expenditures and annual maintenance costs which are typically lower than gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar powered pumps includes the capital cost of replacing the pump with a solar powered pump and operating cost. The operating costs are estimated to be 10 percent of the capital costs. Based on Natural Gas STAR document, "PRO Fact Sheet:

Convert Natural Gas-Driven Chemical Pumps”<sup>84</sup>, the cost for solar-powered electric pumps are approximately \$2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor are \$2,227 (2012 dollars). The EPA estimates there would be no additional annual operating cost for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a natural gas-driven pump with a solar pump is \$317. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year for diaphragm pumps and \$87 per year per piston pump.

#### *6.2.1.4 Secondary Impacts*

No secondary impacts from conversion to solar powered pumps are expected.

### *6.2.2 Electric Pumps*

#### *6.2.2.1 Emission Reduction Potential*

Electric pumps also provide the same functionality as gas-driven pumps, and are only restricted by availability of a reliable source of electricity. Electric pumps have zero natural gas emissions, as summarized in Table 6-4, and converting gas-driven chemical pumps to an electric pump can reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

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<sup>84</sup> U.S. EPA. PRO Fact Sheet No. 202. Convert Natural Gas-Driven Chemical Pumps. Available at <http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf>.

### 6.2.2.2 Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at processing plants or large dehydration facilities that have access to reliable power.

### 6.2.2.3 Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, “PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,”<sup>85</sup> the cost of electric pumps to replace diaphragm pumps is \$4,647 and to replace a piston pump is \$1,819 in 2012 dollars depending on the horsepower of the unit.<sup>86</sup> The annual operating costs for the electric pumps is estimated to be \$293. Annualizing the capital cost over the life expectancy of the pump at a 7 percent discount rate, the annual cost for replacing a natural gas-driven pump with an electric pump is \$954 for diaphragm pump, and \$552 for a piston. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year for diaphragm pumps and \$87 per year per piston pump.

### 6.2.2.4 Secondary Impacts

The secondary impacts from electric pumps are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

## 6.2.3 Instrument Air System

### 6.2.3.1 Process Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same natural gas-driven pumps can be used for natural gas and compressed air, without altering any of the parts of the pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to a reliable source of electricity can install an instrument air system. A description of each of the

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<sup>85</sup> Ibid.

<sup>86</sup> U.S. EPA. Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps. Available online - [http://www.epa.gov/gasstar/documents/ll\\_glycol\\_pumps3.pdf](http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf).

components as described in the Natural Gas STAR document, “PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air”:<sup>87</sup>

- Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.
- Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, without affecting the process control functions.

#### *6.2.3.2 Emission Reduction Potential and Effectiveness*

Instrument air eliminates all emissions from natural gas-driven pumps, but can only be used in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more

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<sup>87</sup> See footnote 78.

economical and therefore more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.<sup>88</sup> Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

#### *6.2.3.3 Cost Impacts*

As stated earlier, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of natural gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.<sup>89</sup>

For natural gas processing, the cost of emission reductions of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because the EPA assumes new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. As was discussed in the 2011 NSPS TSD, the EPA assumes that existing processing plants have an instrument air system in place, including backup systems, and that the cost of adding additional air load to the system would be confined to the incremental cost of upgrading or replacing the compressor and connecting the natural gas-driven pumps to the system. Therefore, for this analysis, the cost being attributed to the replacement of natural gas-driven pumps with air-driven pumps includes the annualized cost of replacing or adding a compressor and installation of the associated piping to connect the pumps to the existing system, and the associated energy costs for operating the new

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<sup>88</sup> U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.

<sup>89</sup> Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.

compressor. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps.

Because the EPA has no data to characterize the number and types of gas-driven pumps at natural gas processing plants, the EPA developed several model plant scenarios that would likely cover a reasonable range of the numbers and types of pumps that might be found at natural gas processing plants. The model plants represented processing plants with 4, 10, 20, 50 and 100 total pumps. Because there is a significant variation in emission profiles between natural gas-driven diaphragm and piston pumps, the EPA also evaluated, within each model plant, three distribution scenarios for the pumps (i.e., 50 percent diaphragm and 50 percent piston, 25 percent diaphragm and 75 percent piston, and 75 percent diaphragm and 25 percent piston.). In our analysis, the EPA determined the total additional air capacity needed based on the estimated natural gas emission rate for the two types of natural gas-driven pumps, and based on the model plant scenarios, determined the volume of additional air capacity that would need to be addressed by the compressor. The EPA then based the analysis on the use of 90 percent of available capacity of the system. The EPA determined that there were basically three sizes (small, medium and large) compressors that would address the range of model plants. Table 6-4 summarizes the model plant analysis of required system capacity and potential emission reductions. The compressor costs used in our analysis were drawn from the costing analysis conducted for the 2011 NSPS proposal for instrument air systems for pneumatic controllers (See Section 5 of the 2011 TSD). The EPA estimated costs, including operating costs, at three size levels; small, medium and large. Table 6-5 summarizes the cost replacement of the various size compressors into an existing instrument air system.

Because gas emissions are avoided, the use of an instrument air system to control natural gas-driven pumps will have natural gas savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pumps and \$87 per year per piston pump.

#### *6.2.3.4 Secondary Impacts*

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.



**Table 6-4. Model Plant Characterization for Replacing Gas-Driven Pumps with Instrument Air System**

Model Plant Size	Annual Compressor Cost <sup>a</sup>	Pump Distribution Scenario <sup>b</sup>	Total Number of Pumps	Number of Diaphragm Pumps	Number of Piston Pumps	Total Additional Air Capacity Required (scf/hour)	Gas Saved <sup>c</sup> (Mcf)	Emission reductions <sup>d</sup> (tpy)	
								Methane	VOC
Small	10,051	50/50	4	2	2	50	49.8	7.7	2.1
		75/25	4	3	1	70	69.8	10.8	3.0
		25/75	4	1	3	30	29.9	4.6	1.3
Medium Small	10,051	50/50	10	5	5	125	124.6	19.2	5.3
		75/25	10	7.5	2.5	175	174.5	26.9	7.5
		25/75	10	2.5	7.5	75	74.7	11.5	3.2
Medium	32,271	50/50	20	10	10	249	249.2	38.4	10.7
		75/25	20	15	5	349	349.1	53.8	15.0
		25/75	20	5	15	149	149.4	23.0	6.4
Medium Large	72,394	50/50	50	25	25	623	623.1	96.0	26.7
		75/25	50	37.5	12.5	873	872.7	134.5	37.4
		25/75	50	12.5	37.5	374	373.5	57.5	16.0
Large	72,394	50/50	100	50	50	1,246	1246.2	192.0	53.4
		75/25	100	75	25	1,745	1745.4	269.0	74.8
		25/75	100	25	75	747	747.0	115.0	32.0

a. See Table 6-5 for the compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

**Table 6-5. Cost of Compressor Replacement for Existing Instrument Air System**

<b>Compressor Size</b>	<b>Air Capacity (scf/hour)</b>	<b>Capital Cost (\$)</b>	<b>Capital Cost + Installation<sup>a</sup> (2008)</b>	<b>Total Capital Cost<sup>b</sup> (\$2012)</b>	<b>Annualized Cost<sup>c</sup> (\$)</b>	<b>Labor Cost (\$2008)</b>	<b>Power Cost (\$2008)</b>	<b>Total O&amp;M<sup>d</sup> (\$2008)</b>	<b>Total O&amp;M<sup>d</sup> (\$2012)</b>	<b>Annual Cost<sup>e</sup> (\$)</b>
Small	135	\$3,772	\$5,658	\$5,999	\$854	\$1,334	\$7,340	\$8,674	\$9,197	\$10,051
Medium	562	\$18,855	\$28,282	\$29,989	\$4,270	\$4,333	\$22,075	\$26,408	\$28,002	\$32,271
Large	1,350	\$33,183	\$49,775	\$52,779	\$7,515	\$5,999	\$55,188	\$61,187	\$64,880	\$72,394

a. Installation cost is estimated to be 50 percent of capital cost.

b. Cost was escalated to 2012 using the FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (<http://research.stlouisfed.org/fred2/series/GDPDEF/#>).

c. Annualized capital cost using a 7% interest rate and an equipment life of 10 years.

d. The total O&M includes both the annual labor cost and the annual power cost.

e. The total annual cost includes the annualized capital cost and the total O&M.

## 6.2.4 *Install or Route Gas to Combustion Device*

### 6.2.4.1 *Emission Reduction Potential*

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas emitted, but rather combusts the gas volume. Costs for routing the natural gas to a combustion device are further described in Table 6-3. The EPA estimates capture and combustion device efficiency to be 95 percent reduction. Therefore, methane reductions are estimated to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a combustion device will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

### 6.2.4.2 *Effectiveness*

Capture systems combined with combustion devices are considered a reliable mechanism to reduce approximately 95 percent of emissions. Each combustion device requires a reliable ignition source where the average gas consumption per pilot burner is 70 scf per hour.<sup>90</sup> Most processing plants or large dehydration facilities already have at least one existing combustion device.

### 6.2.4.3 *Cost Impacts*

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital costs and operating costs. Based on the analysis conducted for the 2012 NSPS for a combustion device to control emissions from storage vessels,<sup>91</sup> the capital cost for installing a new combustion device is \$32,301 in 2008 dollars. The EPA estimates that the capital cost for installing a new combustion device is \$34,250 and the annual operating costs are \$17,001 in 2012 dollars. Based on the life expectancy for a combustion device, the EPA estimate the annualized cost of installing a new combustion device to be \$21,877 using a 7 percent discount rate. For the proposal, the estimated annualized cost of routing emissions to an existing combustion device was \$285 using a 7 percent discount rate. Because the gas captured is combusted there is no gas savings associated with use of a combustion device.

Based on comments received from the proposal, the EPA revised our estimated cost for routing emissions to an existing control device. EPA received cost estimates from two commenters that claimed

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<sup>90</sup> Ibid.

<sup>91</sup> U.S. EPA docket ID: EPA-HQ-OAR-2010-0505-0045.

that the proposed cost estimate for routing emissions to an existing control device or process was too low. One commenter<sup>92</sup> claimed that there were engineering costs in addition to the cost to pipe emissions in a closed vent system (CVS) to a control device and that the total capital cost would be \$5,800. Another commenter<sup>93</sup> provided detailed cost with respect to installing a CVS that considers that there could be a significant distance between the pump location and the control device on a site. This commenter suggested that the cost would be \$8,500 to route emissions through a CVS to an existing control device.

The cost estimates the EPA received from the commenters were not directly comparable to each other, nor were they directly comparable to the proposal cost estimate. Therefore, in order to consider the additional costs provided by the commenters in our analysis, the EPA treated the costs as individual, all-inclusive cost estimates for routing emissions to an existing control device. The EPA calculated the average of the capital cost from proposal and the two commenter estimates and found the estimated capital cost to be \$5,433. Using the 7 percent discount rate, the EPA calculated the annualized cost for each of the commenter estimates to be \$826 (from the \$5,800 estimate) and \$1,210 (from the \$8,500 estimate). The EPA averaged these annualized costs with the proposed annualized cost of \$285 which resulted in a revised annualized cost of \$774.

#### *6.2.4.4 Secondary Impacts*

There are secondary impacts from combustion of emissions routed from natural gas-driven pumps. The combustion of the recovered natural gas creates secondary emissions of hydrocarbons, NO<sub>x</sub>, CO<sub>2</sub>, and CO. A summary of the estimated secondary emission are presented in Table 6-6. No other wastes should be created or wastewater generated.

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<sup>92</sup> EPA-HQ-OAR-2010-0505-6884-A1.

<sup>93</sup> EPA-HQ-OAR-2010-0505-6881.

**Table 6-6. Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device**

Pump Type	Secondary Impacts (tpy)				
	THC <sup>a</sup>	CO <sup>b</sup>	CO <sub>2</sub> <sup>c</sup>	NO <sub>x</sub> <sup>d</sup>	PM <sup>e</sup>
Diaphragm	0.02	0.03	14	0.01	0
Piston	0.002	0.004	2	0.001	0

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a “lightly smoking” flare.

## 6.2.5 Install or Route Gas to VRU

### 6.2.5.1 Emission Reduction Potential

Use of a vapor recovery technology has the potential to reduce the emissions from natural gas-drive pumps by 100 percent if all vapor is recovered. However, the effectiveness of the gas capture system and downtime for maintenance would reduce capture efficiency and therefore, the EPA estimates that routing emissions from a natural gas-driven pump to an existing VRU, or a newly installed VRU can reduce the gas emitted by approximately 95 percent, while at the same time, capturing the gas for beneficial use. The EPA estimates that methane emission reductions for routing gas to a VRU to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a VRU will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

### 6.2.5.2 Effectiveness

VRUs are reliable, typically with a backup compressor system to allow for shutdowns and repairs. VRUs are more economical for facilities with multiple gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants and large dehydration facilities.

### 6.2.5.3 Cost Impacts

Routing natural gas to an existing VRU or installing a new VRU, have both capital costs and maintenance costs. Based on the analysis conducted for the 2012 NSPS for control of emissions from

storage vessels<sup>94</sup>, the capital cost and installation costs for a VRU is estimated to be \$98,186 in 2008 dollars. The EPA estimates the capital cost of installation of a VRU to be \$104,111 and the annual operation and maintenance cost to be \$9,932 in 2012 dollars. If a VRU is already on site, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. The total annualized cost of a new VRU is estimated to be \$24,755 based on a 7 percent discount rate.

As discussed above, for the proposal the EPA estimated the cost of routing emissions to an existing VRU to be \$2,000 in 2012 dollars. The annualized cost of routing gas to an existing VRU is estimated to be \$285 based on a 7 percent discount rate. In addition, because there is potential for beneficial use of gas recovered through the VRU, the EPA estimates an annual gas recovered as 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The gas savings realized is estimated to be \$749 per diaphragm pump and \$84 per piston pump, per year based on \$4.00 value per Mcf of gas recovered.

As discussed above in section 6.2.4.3 with respect to routing emissions to an existing combustion control device, the EPA considered additional cost estimates submitted during the proposed rule public comment period and have revised the estimated cost for routing emissions to an existing VRU to be the same as the cost of routing to an existing combustion device, or \$774 annualized cost.

#### *6.2.5.4 Secondary Impacts*

The secondary impacts from use of a VRU are indirect, variable and dependent on the electrical supply used to power the VRU. No other secondary impacts are expected.

### **6.3 Regulatory Options**

The control technologies evaluated for natural gas-driven pumps included options that provided 100 percent emission reductions. These options included replacing the pumps with solar-powered pumps or electric pumps or use of instrument air systems to eliminate natural gas emissions. The EPA also evaluated gas recovery and gas combustion technologies that would result in 95 percent emission reductions.

The use of instrument air systems and electric pumps requires a consistent supply of electric power and the use of solar-powered pumps and routing emissions to a VRU requires a reliable supply of backup electric power. Because reliable electric power is not universally available for production, gathering and boosting and transmission and storage locations these control technologies were

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<sup>94</sup> Ibid.

determined to not be technically viable options for those segments. Because electric power is typically available at natural gas processing plants, those technologies are considered technically viable for the processing segment.

For the final rule, we have revaluated our best available emissions and usage data for piston pumps. Based on our emissions data these pumps have inherently low emissions primarily due to size. In addition, available information indicates that these pumps are typically used intermittently which further limits their emission potential. Therefore, we determined that based on their low emissions, control of piston pumps is not warranted at this time and we have excluded piston pumps from further evaluation.

Based on the costs and estimated emission reductions for each of the viable emission control alternatives, the EPA further evaluated the cost per ton of emissions reduced for methane and VOC. The cost per ton of emissions reduced was calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to one pollutant and zero cost to the other. The second method, or the multipollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This multipollutant approach is based on estimates of the percentage reduction expected for each pollutant.

Based on the above considerations, for the proposal the EPA evaluated the following regulatory alternatives:

- Regulatory Option 1. Require a zero emission standard for diaphragm pumps at natural gas processing plants.
- Regulatory Option 2. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities.
- Regulatory Option 3. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities only where an existing control device or process is available.

#### *6.3.1 Evaluation of Regulatory Options*

Regulatory Option 1 would require zero emissions of methane and VOC from gas-driven, diaphragm pumps at natural gas processing plants. To attain this emission reduction, the facility would need to either replace the natural gas-driven diaphragm pumps with solar-powered or electric pumps or use instrument air systems to replace natural gas-driven function with air-driven function. The EPA evaluated the cost of control for each of these options based on the estimated emission reductions as detailed above.

Using the single-pollutant (allocate all of the costs to one pollutant and zero to the other) for calculating cost of control, for the use of an instrument air system at natural gas processing plants the EPA estimates the cost per ton of methane reduced to be between \$374 and \$2,185 and the cost per ton of VOC reduced to be between \$1,344 and \$7,861 without considering gas savings. With gas savings, for the use of an instrument air system at natural gas processing plants, the cost per ton of methane reduced was \$146 and \$1,957, and the cost per ton of VOC reduced was between \$527 and \$7,042. Using the multi-pollutant method of allocating cost between methane and VOC, the EPA estimates the cost of control, without considering gas savings, ranged from \$187 to 1,093 per ton of methane reduced and \$672 and \$3,930 per ton of VOC reduced. When considering gas savings, the EPA found the cost of control to range from \$73 to \$979 per ton of methane reduced and \$263 to \$3,521 per ton of VOC reduced. The range of cost per ton is dependent on the size of the system/compressor needed for the facility.

Under the single pollutant approach, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pumps to be between (\$136) and \$1,223 per ton of methane reduced or between (\$489) and \$4,235 per ton of VOC reduced, considering gas savings.<sup>95</sup> Under the multi-pollutant approach and considering savings, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pump to be between (\$68) and \$1,337 per ton of methane reduced and between (\$244) and \$2,112 per ton of VOC reduced, considering gas savings. The EPA considers these costs to be reasonable. Based on these cost of control values for methane and VOC, EPA determined that Regulatory Option 1 is appropriate for the natural gas processing segment. Tables 6-7 through 6-10 summarize the cost of control for each of these options for the natural gas processing segment. For the final rule, the EPA had no changes to this analysis for natural gas processing plants.

The control technologies that produce zero emissions (or 100 percent reduction in emissions) (i.e., solar-powered and electric pumps and instrument air systems) are not technically viable alternatives for the production and transmission and storage segments where reliable electric power is not universally available. Instead, the available control technologies for those segments produce a 95 percent emission reduction. Therefore, the second regulatory option would require a 95 percent reduction in emissions at production sites, transmission stations and storage facilities. To attain this emission reduction, the facility could route emissions to a VRU or a combustion device.

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<sup>95</sup> Negative cost reflects a net savings considering gas saved.



For the proposal, the EPA calculated the cost of control for this option for each control technology by the single-pollutant and multi-pollutant methods described above. For the installation of a new VRU or combustion device, the cost of control for methane and VOC emission reductions ranged from \$3,652 to over \$1 million per ton. The cost of control for a new combustion device ranged between \$3,328 to over \$1 million per ton. Based on these cost of control values for methane and VOC, Regulatory Option 2 was rejected for all segments. For the final rule, the EPA had no changes to this analysis. Tables 6-11 through 6-14 summarize the cost of control for Option 2 for all segments.

For the proposal, EPA evaluated Regulatory Option 3 to require 95 percent control of emissions in all segments only where an existing control device or process was available. The sole cost associated with this option that would be attributed to the emission reduction would be the cost of routing the diaphragm pump emissions to the control device. As discussed above, for the final rule, the EPA has revised the estimated cost to route emissions to either an existing VRU or an existing combustion device based on commenter provided cost estimates. Under the new analysis the capital cost is approximately \$5,433, which when annualized at a 7 percent discount rate, resulted in an annualized cost of \$774. Based on this annualized cost, using the single-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is \$235 per ton for all segments. The cost of control for VOC reductions is \$847 per ton for the production and processing segments and \$8,496 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is \$8 per ton for all segments. The cost of control for VOC emission reductions is \$27 per ton for the production and processing segments and \$274 per ton for the transmission and storage segment.

Using the multi-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is \$118 per ton for all segments. The cost of control for VOC reductions is \$423 per ton for the production and processing segments and \$4,248 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is \$4 per ton for all segments. The cost of control for VOC emission reductions is \$14 per ton for the production and processing segments and \$137 per ton for the transmission and storage segment... EPA found these methane costs to be reasonable and selected Option 3 for control of natural gas-driven diaphragm pump emissions for all segments. Tables 6-15 through 6-16 summarize results of our cost of control analyses.

**Table 6-7. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Single-Pollutant<sup>96</sup>**

Plant Size	Compressor Cost <sup>a</sup>	Scenario <sup>b</sup>	Total Number of Pumps	Total Gas Saved <sup>c</sup> (Mcf)	Emission reductions <sup>d</sup> (tpy)		Cost of control (without savings) (\$/ton)		Cost of control (with savings) <sup>c</sup> (\$/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	\$10,051	50/50	4	49.8	7.7	2.1	\$1,309	\$4,708	\$1,081	\$3,890
		75/25	4	69.8	10.8	3.0	\$934	\$3,360	\$707	\$2,543
		25/75	4	29.9	4.6	1.3	\$2,185	\$7,861	\$1,957	\$7,042
Medium Small	\$10,051	50/50	10	124.6	19.2	5.3	\$523	\$1,883	\$296	\$1,065
		75/25	10	174.5	26.9	7.5	\$374	\$1,344	\$146	\$527
		25/75	10	74.7	11.5	3.2	\$874	\$3,144	\$646	\$2,325
Medium	\$32,271	50/50	20	249.2	38.4	10.7	\$840	\$3,023	\$613	\$2,205
		75/25	20	349.1	53.8	15.0	\$600	\$2,158	\$373	\$1,340
		25/75	20	149.4	23.0	6.4	\$1,403	\$5,048	\$1,175	\$4,229
Medium Large	\$72,394	50/50	50	623.1	96.0	26.7	\$837	\$3,011	\$527	\$1,895
		75/25	50	872.7	134.5	37.4	\$558	\$2,007	\$311	\$1,119
		25/75	50	373.5	57.5	16.0	\$1,674	\$6,022	\$1,031	\$3,711
Large	\$72,394	50/50	100	1246.2	192.0	53.4	\$418	\$1,505	\$150	\$539
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	\$837	\$3,011	\$402	\$1,446

a. See Table 6-5 for compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

<sup>96</sup> As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

**Table 6-8. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Multi-Pollutant Method**

Plant Size	Compressor Cost <sup>a</sup>	Scenario <sup>b</sup>	Total Number of Pumps	Total Gas Saved <sup>c</sup> (Mcf)	Emission reductions <sup>d</sup> (tpy)		Cost of Control (without savings) (\$/ton)		Cost of Control (with savings) <sup>c</sup> (\$/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	\$10,051	50/50	4	49.8	7.7	2.1	\$654	\$2,354	\$541	\$1,945
		75/25	4	69.8	10.8	3.0	\$467	\$1,680	\$353	\$1,271
		25/75	4	29.9	4.6	1.3	\$1,093	\$3,930	\$979	\$3,521
Medium Small	\$10,051	50/50	10	124.6	19.2	5.3	\$262	\$942	\$148	\$533
		75/25	10	174.5	26.9	7.5	\$187	\$672	\$73	\$263
		25/75	10	74.7	11.5	3.2	\$437	\$1,572	\$323	\$1,163
Medium	\$32,271	50/50	20	249.2	38.4	10.7	\$420	\$1,512	\$307	\$1,103
		75/25	20	349.1	53.8	15.0	\$300	\$1,079	\$186	\$670
		25/75	20	149.4	23.0	6.4	\$702	\$2,524	\$588	\$2,114
Medium Large	\$72,394	50/50	50	623.1	96.0	26.7	\$418	\$1,505	\$263	\$948
		75/25	50	872.7	134.5	37.4	\$279	\$1,004	\$156	\$559
		25/75	50	373.5	57.5	16.0	\$837	\$3,011	\$516	\$1,855
Large	\$72,394	50/50	100	1246.2	192.0	53.4	\$209	\$753	\$75	\$269
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	\$418	\$1,505	\$201	\$723

a. See Table 6-5 for compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in \$786 savings per diaphragm pump and \$87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

**Table 6-9. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Single-Pollutant<sup>97</sup>**

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
					Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
		Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm	Electric <sup>a</sup>	3.46	0.96	4,175	22.45	197	\$786	\$276	\$994	\$49	\$175
Diaphragm	Solar	3.46	0.96	\$2,000	22.45	197	\$786	\$92	\$330	(\$136)	(\$489)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

**Table 6-10. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Multi-Pollutant Method**

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
					Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
		Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm	Electric <sup>a</sup>	3.46	0.96	\$4,175	22.45	197	\$786	\$138	\$497	\$24	\$88
Diaphragm	Solar	3.46	0.96	\$2,000	22.45	197	\$786	\$46	\$165	(\$68)	(\$244)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

<sup>97</sup> See footnote 50.

**Table 6-11. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Single-Pollutant Method**

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$24,755	22.45	187	\$749	\$7,531	\$27,094	\$7,304	\$26,275
Processing	3.29	0.91	\$24,755	22.45	187	\$749	\$7,531	\$27,094	\$7,304	\$26,275
Transmission	3.29	0.09	\$24,755	22.45	187	\$749	\$7,531	\$271,888	\$7,304	\$263,666
Storage	3.29	0.09	\$24,755	22.45	187	\$749	\$7,531	\$271,888	\$7,304	\$263,666

*Note: No gas savings is attributed to transmission and storage.*

**Table 6-12. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Multi-Pollutant Method**

Segment	Emission Reductions (tpy/pump)		Annualized Cost (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value (\$)	without savings		with savings	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$24,755	22.45	187	\$749	\$3,766	\$13,547	\$3,652	\$13,137
Processing	3.29	0.91	\$24,755	22.45	187	\$749	\$3,766	\$13,547	\$3,652	\$13,137
Transmission	3.29	0.09	\$24,755	22.45	187	\$749	\$3,766	\$135,944	\$3,652	\$131,833
Storage	3.29	0.09	\$24,755	22.45	187	\$749	\$3,766	\$135,944	\$3,652	\$131,833

*Note: No gas savings is attributed to transmission and storage.*

**Table 6-13. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Single-Pollutant Method**

Segment	Type of Pump	Emission reductions (tons/yr-pump)		Annualized Cost (\$2012)	Cost of Control (\$/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	\$21,877	\$6,656	\$23,944
Processing	Diaphragm	3.287	0.914	\$21,877	\$6,656	\$23,944
Transmission	Diaphragm	3.287	0.091	\$21,877	\$6,656	\$240,279
Storage	Diaphragm	3.287	0.091	\$21,877	\$6,656	\$240,279

**Table 6-14. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Multi-Pollutant Method**

Segment	Type of Pump	Individual Pneumatic Pump Emission Reductions (tons/yr-pump)		Annualized Cost (\$2012)	Cost of Control (\$/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	\$21,877	\$3,328	\$11,972
Processing	Diaphragm	3.287	0.914	\$21,877	\$3,328	\$11,972
Transmission	Diaphragm	3.287	0.091	\$21,877	\$3,328	\$120,140
Storage	Diaphragm	3.287	0.091	\$21,877	\$3,328	\$120,140

**Table 6-15. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Single-Pollutant Method**

Pump Type/ Segment	Emission Reductions <sup>a</sup> (tpy/pump)		Annualized Cost <sup>b</sup> (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/ yr)	Value <sup>c</sup> (\$)	without savings		with savings <sup>d</sup>	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$774	22.45	187	\$749	\$235	\$847	\$8	\$27
Processing	3.29	0.91	\$774	22.45	187	\$749	\$235	\$847	\$8	\$27
Transmission	3.29	0.09	\$774	22.45	187	\$749	\$235	\$8,496	\$8	\$274
Storage	3.29	0.09	\$774	22.45	187	\$749	\$235	\$8,496	\$8	\$274

a. Based on 95 percent control.

b. Based on capital cost of \$5,433 annualized using a 7 percent discount rate.

c. Based on \$4.00 per Mcf average price for natural gas.

d. Applies to VRU only. There is no gas savings with a combustion device.

**Table 6-16. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Multi-Pollutant Method**

Pump Type/ Segment	Emission Reductions <sup>a</sup> (tpy/pump)		Annualized Cost <sup>b</sup> (\$)	Natural Gas			Cost of Control (\$/ton)			
	Methane	VOC		Emission Factor (scf/h)	Saved (Mcf/yr)	Value <sup>c</sup> (\$)	without savings		with savings <sup>d</sup>	
							Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	\$774	22.45	187	\$749	\$118	\$423	\$4	\$14
Processing	3.29	0.91	\$774	22.45	187	\$749	\$118	\$423	\$4	\$14
Transmission	3.29	0.09	\$774	22.45	187	\$749	\$118	\$4,248	\$4	\$137
Storage	3.29	0.09	\$774	22.45	187	\$749	\$118	\$4,248	\$4	\$137

a. Based on 95 percent control.

b. Based on capital cost of \$5,433 annualized using a 7 percent discount rate.

c. Based on \$4.00 per Mcf average price for natural gas.

d. Applies to VRU only. There is no gas savings with a combustion device.



## 7.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors.

The 2012 NSPS promulgated requirements for control of emissions from wet seal centrifugal compressors and reciprocating compressors in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD for information on the production and processing segments.

This chapter discusses the emissions from these compressors in the transmission and storage segment and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

### 7.1 Process Description

#### 7.1.1 *Reciprocating Compressors*

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

#### 7.1.2 *Centrifugal Compressors*

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy.

These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs. The opposing forces create a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are typically lower for dry seals in comparison to wet seals.

## 7.2 Emissions Data and Emissions Factors

### 7.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide emission estimates from reciprocating and centrifugal compressors. These studies are provided in Table 7-1, along with the type of information contained in the study.

**Table 7-1. Major Studies Reviewed for Emissions and Activity Data**

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Public review draft Inventory of U.S. GHG Emissions and Sinks: 1990-2014 <sup>a</sup>	EPA	2016	Nationwide	X	
GHG Mandatory Reporting Rule and TSD <sup>b</sup>	EPA	2013	Nationwide	X	
Methane Emissions from the Natural Gas Industry <sup>c</sup>	GRI/EPA	1996	Nationwide	X	
Natural Gas STAR Program <sup>d,e</sup>	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study <sup>f</sup>	URS Corporation, UT Austin, and U.S. EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and	API/ANGA	2012	Regional	X <sup>h</sup>	

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Analysis of API and ANGA Survey Responses <sup>g, h</sup>					
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries <sup>i</sup>	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

a. U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.

b. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2014.

c. National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, EIA. EPA-600/R-96-080h. June 1996.

d. U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. EPA. 2006.

e. U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals In Centrifugal Compressors. *Natural Gas STAR*. EPA. 2006.

f. URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011.

[http://www.utexas.edu/research/ceer/GHG/files/FReports/XA\\_83376101\\_Final\\_Report.pdf](http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf).

g. API and America's Natural Gas Alliance (ANGA). 2012. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses. Final Report. September 21, 2012.

h. The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emissions information was included.

i. ICF International. 2014. Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries. Prepared for the Environmental Defense Fund. March 2014.

### 7.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study<sup>98</sup> and the methane-to-VOC ratio developed in the gas composition memorandum.<sup>99</sup> The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 lbs of methane per Mcf. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 7-2. Once the methane emissions were calculated, the ratio of VOC-to-methane

<sup>98</sup> National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

<sup>99</sup> See footnote 3.

was used to estimate VOC emissions. The specific VOC-to-methane ratios used for this analysis were 0.278 lbs VOC per pound of methane for the production and processing segments, and 0.0277 lbs VOC per pound of methane for the transmission and storage segment. A summary of the reciprocating compressor emissions are presented in Table 7-3.

The centrifugal compressor emission factors for wet seals and dry seals are based on data used in the GHG Inventory<sup>100</sup>. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.<sup>101</sup>

Since publication of the white paper, additional data have become available on compressor emissions in transmission and storage, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015. These data confirm the significant emissions from these sources, but indicate that emissions levels differ from those assumed in this analysis. In the 2013 GHGRP transmission and storage data set, reported emissions from reciprocating compressors are 2,100,647 tons CO<sub>2</sub> Eq. of methane, and reported emissions from centrifugal compressors are 697,643 tons CO<sub>2</sub> Eq. of methane. The Subramanian study, compared total average methane emissions per compressor in transmission and storage for both reciprocating and centrifugal compressors to those in the 2015 GHG Inventory, and found that the 2015 GHG Inventory had higher average emissions. The 2016 GHGI inventory includes updated estimates for reciprocating and centrifugal compressors, based on data from the Subramanian study and GHGRP.

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<sup>100</sup> U.S. EPA. Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014.

<sup>101</sup> Ibid.

**Table 7-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors**

Compressor Station	Reciprocating Compressors			Centrifugal Compressors		
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor <sup>a</sup>	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)	Pressurized Factor <sup>a</sup>
Transmission	57 <sup>b</sup>	3.3	79.1%	47.7 <sup>d</sup>	6 <sup>d</sup>	30.0 <sup>d</sup>
Storage	51 <sup>c</sup>	4.5	67.5%	47.7 <sup>d</sup>	6 <sup>d</sup>	22.4 <sup>d</sup>

a. Percent of hours per year that a compressor is pressurized.

b. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.

c. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.

d. U.S. EPA. Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014. Annex 3.5 Table A-129.

**Table 7-3. Baseline Emission Estimates for Reciprocating and Centrifugal Compressors**

Compressor Location	Baseline Emission Estimates (tpy)	
	Methane	VOC
<b>Reciprocating Compressors</b>		
Transmission	27.1	0.75
Storage	28.2	0.78
<b>Centrifugal Compressors (Wet Seals)</b>		
Transmission	157	4.34
Storage	117	3.24
<b>Centrifugal Compressors (Dry Seals)</b>		
Transmission	19.7	0.546
Storage	14.7	0.407

## 7.3 Control Techniques

### 7.3.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas across the piston rod packing. This includes replacement of the compressor rod packing or replacement of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas across the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings

reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate option for reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.<sup>102</sup> Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a combustion device. A summary of these techniques are presented in the following sections.

One control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a combustion device was considered to be a viable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. “Beam” type compressors have two seals, one on each end of the compressor, while “over-hung” compressors have a seal on only the “inboard” (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes “O-

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<sup>102</sup> U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. Washington DC. 2006.

ring” rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the “inboard” (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a combustion device.

### 7.3.2 Reciprocating Compressor Rod Packing Replacement

#### 7.3.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the rod packing ensures the correct fit is maintained between packing rings and the rod.

#### 7.3.2.2 Emissions Reduction Potential

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The emission reductions for the transmission and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors (as presented in Table 6-2) and the average emission factor for newly installed rod packing. This calculation, shown in the Equation 1 below, was performed for the transmission and storage segment.

**Equation 1**

$$R_{PTS} = \frac{Comp_{New}^{PTS} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6}$$

where:

$R_{PTS}$  = Potential methane emission reductions from transmission or storage compressors replacing rod packing, in million cubic feet per year (MMcf/year).

$Comp_{New}^{PTS}$  = Number of new transmission or storage compressors.

$E_{G\&B}$  = Methane emission factor for transmission or storage compressors in Table 7-2, in cubic feet per hour per cylinder.

$E_{New}$  = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder<sup>103</sup> for this analysis.

$C$  = Average number of cylinders for transmission or storage compressors in Table 7-2.

$O$  = Percent of time during the calendar year the average transmission or storage compressor is in the operating and standby pressurized modes, 79.1%, 67.5% respectively.

8760 = Number of days in a year.

$10^6$  = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating compressor rod packing replacement in the transmission and storage segment is presented in Table 7-4. The emissions of VOC were estimated using the methane emissions calculated above and the methane-to-VOC- ratio developed for each of the segments in the gas composition analysis conducted for the NSPS.<sup>104</sup>

**Table 7-4. Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing for a Typical Year**

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Typical Year					
Transmission	15	21.7	0.601	325	9
Storage	17	21.8	0.605	109	10

### 7.3.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas STAR Lessons Learned document<sup>105</sup> which estimated the cost to replace the rod packing rings to be \$1,712 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing placement is based on number of hours that the compressor operates, or the time since the last replacement. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program.<sup>106</sup> The

<sup>103</sup> Ibid.

<sup>104</sup> See footnote 3.

<sup>105</sup> See footnote 102.

<sup>106</sup> Ibid.



cost impacts are based on the replacement of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

For the 2012 NSPS, the number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This percentage of hours is, on average, the number of hours per year a reciprocating compressor is pressurized and was used as the basis for the cost evaluation as it was determined to be the best available industry-wide percent pressurized value. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3.8 years for transmission compressors and 4.4 years for storage compressors using the operating factors in Table 7-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3122 for transmission compressors and 0.2720 for storage compressors. The capital costs were calculated using the average rod packing cost of \$1,712 and the average number of cylinders per segment as presented in Table 7-2. The annual costs were calculated using the capital cost and the capital recovery factors.

The cost per ton of emissions reduced was then calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to each pollutant separately. The second method, or multi-pollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant approach was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for the transmission and storage segment is shown in Table 7-5.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement, however, these savings were not included in the cost estimates for the transmission and storage segment because it is assumed that the owner/operator of the compressor generally is not the owner of the natural gas that is compressed at their compressor stations.

**Table 7-5. Cost of Control for Reciprocating Compressor Rod Packing Replacement (\$2012)**

Compressor Location	Capital Cost (\$)	Annual Cost (\$/yr)	Cost of Control		Cost of Control	
			Single-Pollutant Approach		Multi-Pollutant Approach	
			(\$/ton)		(\$/ton)	
			Methane	VOC	Methane	VOC
Transmission	\$5,650	\$1,748	\$81	\$2,910	\$40	\$1,455
Storage	\$7,705	\$2,077	\$95	\$3,434	\$48	\$1,717

#### 7.3.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no maintenance of electrical systems and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing is replaced based on operating hours or time since the last replacement.

### 7.3.3 Centrifugal Compressor Dry Seals

#### 7.3.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. 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 at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce gas emissions compared to wet seals. At the same time, they significantly reduce operating costs and enhance compressor efficiency compared to wet seals. Economic and environmental advantages of using dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of less than 6 scfm methane per compressor.<sup>107</sup> While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.<sup>108, 109</sup>
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.
- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet seal systems require 50 to 100 kilowatt (kW) per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

#### 6.3.3.2 Emissions Reduction Potential

The emission reduction of the dry seal compressor was calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 7-2 were used in combination with an operating factor of 30 percent for transmission centrifugal compressors and 22.4 percent for storage centrifugal

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<sup>107</sup> U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. October 2006. Available at [http://epa.gov/gasstar/documents/ll\\_wetseals.pdf](http://epa.gov/gasstar/documents/ll_wetseals.pdf).

<sup>108</sup> "Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry". US EPA, ICF International, PEMEX, EnCana Oil & Gas, Hy-Bon Engineering, Pluspetrol, Gazprom, VNIIGAZ. World Gas Conference 10/2009. Available at [http://www.epa.gov/gasstar/documents/best\\_paper\\_award.pdf](http://www.epa.gov/gasstar/documents/best_paper_award.pdf).

<sup>109</sup> U.S. Environmental Protection Agency. Methodology for Estimating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2009. Washington, DC. April, 2011. Annex 3. Page A-153.

compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors are based on data from the GHG Inventory.<sup>110</sup> The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.<sup>111</sup> A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 7-6.

**Table 7-6. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals**

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	137	3.79	0	0
Storage	1	102	2.83	102	2.83

#### 7.3.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. From the Natural Gas STAR Program, General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between \$50,000 and \$100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3 percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000 (\$79,268 in 2012 dollars). The annual cost was calculated as the capital recovery of this capital cost assuming a 20-year equipment life and 7 percent interest which came to \$7,482 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of dry seal compressor is \$88,300 in comparison to wet seal compressor. The cost per ton of emissions reduced was then

<sup>110</sup> See footnote 4.

<sup>111</sup> U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR. 2006.

calculated in two ways. The single-pollutant method allocated all of the costs to each pollutant separately. The multi-pollutant method prorated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant method was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for dry seals is presented in Table 7-7 along with the methane and VOC cost of control for the dry seal compressor option. We do not consider revenues from gas savings for transmission and storage facilities because it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station.

**Table 7-7. Cost of Reductions for Centrifugal Compressor Using Dry Seal Compressors (\$2012)**

Compressor Location	Capital Cost (\$)	Annual Cost Per Compressor (\$/compressor-year)		Methane Cost of Control (\$/ton)		VOC Cost of Control (\$/ton)	
		without savings	with O&M savings	without savings	with O&M savings	without savings	with O&M savings
Single-Pollutant							
Transmission	\$79,268	\$7,482	-\$85,843	\$55	-\$627	\$1,974	-\$22,642
Storage	\$79,268	\$7,482	-\$85,843	\$73	-\$840	\$2,643	-\$30,324
Multi-Pollutant Method							
Transmission	\$79,268	\$7,482	-\$85,843	\$27	-\$314	\$987	-\$11,321
Storage	\$79,268	\$7,482	-\$85,843	\$37	-\$420	\$1,322	-\$15,162

#### 7.3.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

### 7.3.4 Centrifugal Compressor Wet Seals Routed to a Combustion Device

#### 7.3.4.1 Description

Another control option used to reduce emissions from centrifugal compressors equipped with wet seals is to route the emissions to a combustion device or capture the emissions and route them to a process (e.g., a fuel system). A wet seal system uses oil that is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas. The

center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to a combustion device or to a process.

#### 7.3.4.2 Emissions Reduction Potential

Combustion devices have been used in the oil and natural gas industry to combust gas streams that have VOC and organic HAP. A combustion device typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves 95 percent reduction of methane, VOC, and organic HAP. The wet seal emissions in Table 7-2 were used along with the control efficiency to calculate the emission reductions from this option. A summary of the emission reductions is presented in Table 7-8.

**Table 7-8. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Combustion Device**

Compressor Station	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	149	4.12	0	0
Storage	1	111	3.08	111	3.08

#### 7.3.4.3 Cost Impacts

The capital and annual cost of the combustion device (an enclosed flare for the analysis) was calculated using the methodology in the EPA Control Cost Manual.<sup>112</sup> The heat content of the gas stream was calculated using information from the gas composition memorandum.<sup>113</sup> A summary of

<sup>112</sup> EPA Air Pollution Control Cost Manual - Sixth Edition, (EPA 452/B-02-001).

<sup>113</sup> See footnote 3.

the capital and annual costs for wet seals routed to a flare is presented in Table 7-9. The cost per ton of emissions reduced was then calculated in two ways. The single-pollutant approach allocated all of the costs to each pollutant separately. The multi-pollutant approach allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. The methane and VOC cost of control for the wet seals routed to a combustion device option is also shown in Table 7-9. There is no cost savings estimated for this option because the recovered gas is combusted.

**Table 7-9. Cost of Control for Centrifugal Compressor Wet Seal Emission Routed to a Combustion Device**

Compressor Location	Capital Cost (\$)		Annual Cost per Compressor (\$/compressor-year)		Cost of Control New CD (\$/ton)		Cost of Control Existing CD (\$/ton)	
	New CD	Existing CD	New CD	Existing CD	Methane	VOC	Methane	VOC
<b>Single-Pollutant</b>								
Transmission	\$71,783	\$23,252	\$114,146	\$3,311	\$767	\$27,705	\$22	\$804
Storage	\$71,783	\$23,252	\$114,146	\$3,311	\$1,028	\$37,105	\$30	\$1,076
<b>Multi-Pollutant Method</b>								
Transmission	\$71,783	\$23,252	\$114,146	\$3,311	\$384	\$13,853	\$11	\$402
Storage	\$71,783	\$23,252	\$114,146	\$3,311	\$514	\$18,553	\$15	\$538

CD = Control Device

#### 7.3.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a combustion device. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO<sub>x</sub>, CO<sub>2</sub>, and CO emissions). A summary of the estimated secondary emission are presented in Table 7-10. No other wastes should be created or wastewater generated.

**Table 7-10. Secondary Impacts from Wet Seal Emissions Routed to a Combustion Device**

Compressor Location	Secondary Impacts from Wet Seals Routed to a Combustion Device (tpy)				
	THC <sup>a</sup>	CO <sup>b</sup>	CO <sub>2</sub> <sup>c</sup>	NO <sub>x</sub> <sup>d</sup>	PM <sup>e</sup>
Transmission	0	0	0	0	0
Storage	0.58	1.29	550	0.28	0.01

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares.

Assumes a “lightly smoking” flare.

## 7.4 Regulatory Options

EPA evaluated the following regulatory options:

- Regulatory Option 1. Require replacement of the reciprocating compressor rod packing based on 26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2. Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3. Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

### 7.4.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 7.3.1. The methane and VOC cost of control for reciprocating compressors at transmission stations is \$81 and \$2,910 per ton, respectively. The methane and VOC cost of control for reciprocating compressors at storage facilities is \$95 and \$3,434 per ton, respectively. Based on these cost of control values for methane, EPA selected Regulatory Option 1 for the transmission and storage segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 7.3.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in



comparison to wet seals. Under the single pollutant approach, the methane and VOC cost of emission reductions for dry seals compressors was calculated to be \$55 per ton and \$1,974 per ton respectively for centrifugal compressors located at transmission facilities, not including the savings from operation and maintenance costs. When those savings were considered the methane and VOC cost of control was calculated to be (\$627) per ton and (\$22,642) per ton. Also under the single pollutant approach, the methane and VOC cost of control for dry seal compressors was calculated to be \$73 per ton and \$2,643 per ton respectively for centrifugal compressors located at storage facilities, not including the savings from operation and maintenance costs.<sup>114</sup> When those savings were considered, the methane and VOC cost of control was calculated to be (\$840) per ton and (\$30,324) per ton. However, commenters on the 2011 Oil and Natural Gas NSPS noted that are certain situations where installing a dry seal system is not feasible, such as where gas composition is inadequate and in retrofits of some existing compressors due to housing design or operational requirements. Therefore, EPA rejected Regulatory Option 2 as a regulatory option for centrifugal compressors located at transmission or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a combustion device or process. Under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be \$767 per ton and \$27,705 per ton respectively for centrifugal compressors located at transmission facilities. Also under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be \$1,028 per ton and \$37,105 per ton respectively for centrifugal compressors located at transmission facilities. However, facilities may already have a combustion device operating at the facility or would route the captured gas back to a useful process rather than flaring it. Those facilities would not incur the additional capital cost and operation and maintenance costs of the flare. Under the single pollutant approach for those facilities the methane and VOC cost of control were calculated to be \$22 per ton and \$804 per ton respectively for transmission facilities and \$30 per ton and \$1,076 per ton respectively for storage facilities. Based on these cost of control values, EPA is selecting Regulatory Option 3 for the transmission and storage segment.

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<sup>114</sup> Negative cost is the result of operation and maintenance savings for dry seals.

## **VOLUME 2: NATIONAL LEVEL IMPACTS**

### **8.0 NATIONWIDE IMPACTS FOR HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS**

#### **8.1 Nationwide Emissions**

##### *8.1.1 Determination of Number of Completions and Recompletions*

The first step in this analysis is to estimate nationwide baseline emissions in 2012, the year selected as the baseline year. In order to develop the baseline emissions, the EPA estimate the average number of wells that would be affected using the number of completions and recompletions performed in a typical year derived from the DrillingInfo database extract as described above. This value was then multiplied by the potential uncontrolled emissions per well completion listed in Table 3-2.

The DrillingInfo database includes the most recent completion date for all reported wells in the US. Therefore, the methodology described above for calculating the number of hydraulically fractured oil well completions from the HPDI® database in 2012 identifies wells initially fractured in 2012 and wells that were refractured (recompletions) in 2012. Because these recompletions are included in the database and resulting extracted dataset, it is not necessary to calculate a refracture frequency.

To more accurately estimate baseline emissions for this analysis, and to ensure no emission reductions were calculated for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. The number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing state regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., the number of wells impacted by local (as opposed to state level) regulations could not be determined because data for wells subject to county or local ordinance level regulations are not available. Therefore, the calculated percentage of wells subject to state regulation based on the identified state regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under state regulations, the DrillingInfo database extract well count data (described

above) was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the states identified as having existing controls. In our proposal, the EPA identified Colorado, and Wyoming as the only states requiring controls on completions comparable to the NSPS requirements prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared.<sup>115</sup> The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to Wyoming, the Colorado Oil and Gas Conservation Commission (COOGCC) requires a renewable energy certificate (REC) for both oil and natural gas wells.<sup>116</sup> It was assumed for proposal that the ratio of wells in Colorado and Wyoming to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in Wyoming to the number of total nationwide wells was assumed to represent the percentage of controlled well recompletions as it was the only state identified as having regulations directly related to recompletions. The EPA used the referenced GOR of less than (<) 100,000 scf/bbl for oil wells to identify the oil wells located in Wyoming and Colorado. From this review it was estimated that 8.81 percent of oil well completions are controlled in absence of federal regulation.

The EPA received significant comment that the proposal did not consider the existing control requirements for a then-proposed, now-final requirements in North Dakota that requires flaring of all emissions during the flowback stage of completions. In particular, the North Dakota Air Pollution Control Rules require that all organic gases and vapors be burned by flares and the North Dakota Industrial Commission requires that all vented casinghead gas be burned, pending arrangements for disposition for some useful purpose.<sup>117</sup> Considering the comments, for the final

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<sup>115</sup> Wyoming BACT permitting guidance. Available at [http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL\\_Oil%20and%20Gas%20Revision\\_UGRB.pdf](http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf).

<sup>116</sup> COGCC 805 Series Rules (805.b.(3)A). Available at <http://cogcc.state.co.us/> and the Colorado Code of Regulations at: <http://www.sos.state.co.us/CCR/Welcome.do>.

<sup>117</sup> N.D. Admin. Code§ 33-15-07-02(1) and§ 43-02-03-45

rule, the EPA determined that the percentage of completions and recompletions conducted in North Dakota for oil wells greater than or equal to 300 GOR was 9.4 percent.

Finally, the EPA determined the number of exploratory oil well completions based on the percentage breakdown between exploratory and development wells in the National Energy Modeling System (NEMS). NEMS is a model of the U.S. energy economy developed and maintained by the EIA. NEMS is used to produce the Annual Energy Outlook (AEO), a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. The NEMS source code is publicly available and fully documented. The source code and accompanying documentation is released annually when a new AEO is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. Based on the NEMS AEO 2014 Reference Case, 3.8 percent of oil wells are exploratory and 96.2 percent are development wells.

In addition, as for the development of the 2012 NSPS for gas well completions, the EPA is aware that some oil well completions and workovers are controlled voluntarily using RECs or combustion devices. However, the EPA could not identify a national level data source on this practice from which the EPA could estimate the numbers of voluntarily controlled oil well completions. Therefore, due to lack of data and a reliable benchmark for estimating the number of voluntarily controlled completions, the EPA assumed zero for our analysis of baseline emissions.

In order to determine nationwide impacts of the number of new oil well completions and recompletions, the EPA used the base year of 2012 activity data (see the 2015 Proposal TSD for details on the 2012 base year projection) as described above and projected activity numbers for the years 2020 and 2025 based on predictions from the NEMS Oil and Gas Supply Model. The EPA calculated the compound annual growth rate (CAGR) between 2012 and 2015 for development and exploratory oil wells based on the AEO 2015 Reference Case. The CAGR for development wells was found to be -0.1 percent and the CAGR for exploratory wells was found to be 6.2 percent. These factors were used to calculate the number of exploratory and development oil well completion for the years 2020 and 2025.

Table 8-1 summarizes the estimated number of hydraulically fractured oil well completions derived from our analysis detailed above.

**Table 8-1. Estimated Number of Hydraulically Fractured Oil Well Completions and Recompletions - 2020 and 2025**

<b>Hydraulically Fractured Oil Well Completions</b>	<b>2020</b>	<b>2025</b>
Total Oil Well Completions and Recompletions	19,703	20,988
<i>Total with &lt; 300 GOR</i>		
Development	4,481	4,774
Exploratory/Delineation	177	188
<i>Total with ≥ 300 GOR</i>		
Development	13,862	14,730
Exploratory/Delineation	1,183	1,296
<i>Total with ≥ 300 GOR and Regulated by States (CO and WY) (Comparable to NSPS)</i>		
Development	1,100	1,168
Exploratory/Delineation	92	101
<i>Total with ≥ 300 GOR and Regulated by States (ND) (Flaring only)</i>		
Development	1,200	1,275
Exploratory/Delineation	103	112
<i>Total with ≥ 300 GOR, Not Regulated by States (CO and WY)</i>		
Development	12,762	13,562
Exploratory/Delineation	1,091	1,195

Because the proposed and final rule requirements affect oil well completions and recompletions differently, particularly where activities are currently controlled under a state regulation, the EPA estimated the number of projected well completions and recompletions which would be affected under different control scenarios under the NSPS. Specifically, the EPA calculated activity numbers for the following control scenarios:

- Development oil wells that are greater than or equal to 300 GOR which are currently venting and are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by a state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2015) and not located in ND and that are capable of conducting a REC. The EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, it is technically infeasible for them to conduct a REC, therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and

13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to technical infeasibility reasons (other than low pressure). See the discussion in 3.3.2.1 with respect to technical infeasibility as being reasons for not being required to conduct a REC. The EPA estimates that 10 percent of these oil wells are not capable of conducting a REC.

- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, due to low pressure cannot conduct a REC, and therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to low pressure. As discussed in section 8.2.1 below, the EPA estimate that 40 percent of these oil wells are not capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently flaring based on state requirements that are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are located in ND and that are capable of conducting a REC. As discussed in section 8.2.1 below the EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- All other development oil wells. This number is the development oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC, plus the greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.
- Exploratory and delineation oil wells that are greater than or equal to 300 GOR and are currently venting which would now be required to combust emissions. This is the number of exploratory and delineation oil wells that are not covered by state regulation in CO or WY and that are not located in ND. The EPA assumes that 100 percent of these wells are venting.
- All other exploratory and delineation oil wells. This number is the exploratory/delineation oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC plus the

greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.

Table 8-2 summarizes the estimates of the numbers of oil well completions and recompletions based on these control scenarios above.

**Table 8-2. Estimated Number of Total Oil Well Completions and Recompletions by Control Scenario under the NSPS for 2020 and 2025**

<b>Estimated Control Scenario Under NSPS</b>	<b>2020</b>	<b>2025</b>
Development Oil Wells (Venting/REC with Combustion)	5,781	6,144
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	1,229
Development Oil Wells (Venting, LP/Combustion)	4,625	4,915
Development Oil Wells (Flaring/REC)	600	637
Development Oil Wells (No change)	6,181	6,580
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	1,083
Exploratory/Delineation Oil Wells (No change)	372	401

REC = Reduced Emissions Completion, TI for REC, Combustion = Technical infeasibility for a REC, combustion required, LP = Low pressure well

### 8.1.2 Nationwide Emission Estimates

Using the estimated emissions per source as shown in Table 3-2, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil well completions and recompletions in the base year 2012 and projected completions and recompletions for the projected years 2020 and 2025 were calculated and are summarized in Table 8-3. All values have been rounded to the nearest ton for estimation purposes.

**Table 8-3. Nationwide Baseline Emissions for 2020 and 2025 from Hydraulically Fractured Oil Well Completions and Recompletions**

Well Source Subcategory	Emissions Per Event (tpy)		Number of Uncontrolled Wells <sup>a</sup>	Baseline Nationwide Emissions (tpy)	
	Methane	VOC		Methane <sup>b</sup>	VOC <sup>b</sup>
Projected Year 2020					
All Oil Wells	9.72	8.14	13,853	122,279	102,396
1. Developmental Oil Wells	9.72	8.14	12,162	112,672	94,351
2. Exploratory/Delineation Oil Wells	9.72	8.14	988	9,607	8,045
Projected Year 2025					
All Oil Wells	9.72	8.14	14,007	130,257	109,078
1. Developmental Oil Wells	9.72	8.14	12,925	119,734	100,266
2. Exploratory/Delineation Oil Wells	9.72	8.14	1,083	10,523	8,812

a. The number of controlled wells is equal to all wells less wells controlled based on state regulations in ND, CO and WY.

b. Based on the assumption that VOC content is 0.8374 lbs VOC per pound methane. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. These values do not account for secondary emissions from portion of gas that is directed to a combustion device.

## 8.2 Nationwide Impacts of the Final Rule (for purposes of Regulatory Impact Analysis)

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to final standards for oil well completions and recompletions. See the rule package for details of the final standards.

### 8.2.1 Primary Environmental Impacts of Regulatory Options

The selected standards for oil well completions and recompletions are as follows:

- Subcategory 1 - Development (i.e., wells which do not meet the definition of exploratory or delineation wells) Oil Well Completions and Recompletions: Operational standard for completions and recompletions with hydraulic fracturing which requires a combination of REC with combustion, but allows for combustion alone or venting during specified situations.
- Subcategory 2 - Exploratory and Delineation Oil Well Completions and Recompletions: An operational standard for completions and recompletions with hydraulic fracturing which requires completion combustion devices with an allowance for venting during specified situations.



As noted in section 3.3.1 above, there are several control scenarios under which an oil well might be affected under the NSPS. The number of completions and recompletions that would be subject to the various regulatory requirements under the NSPS is listed in Table 8-3.

Table 8-4 summarizes the nationwide emission reduction estimates for each of the estimated control scenarios for the projected years 2020 and 2025. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion or recompletion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Additionally, where it is technically infeasible to conduct a REC, the EPA estimated a 95 percent emission reduction as the result of combustion where required. As discussed in section 3.3.2.1 above, there are several instances where conducting a REC is not feasible. The EPA estimate, for the purposes of estimating impacts that 50 percent of oil wells will be capable of conducting a REC and that 40 percent of the oil wells will not be able to conduct a REC due to low pressure in the well. Another 10 percent of the oil wells are estimated to not be able to conduct a REC due to other technical infeasibility such as access to gas lines, inert gas concentration, safety or other hazards where the separator cannot be operated. Nationwide emission reductions were estimated by applying this 95 percent reduction to the uncontrolled baseline emissions presented in Table 3-2.

#### *8.2.2 Nationwide Cost Impacts*

The operational standards for development wells that can conduct a REC include both REC and a completion combustion device, therefore the total incremental cost of the operational standard for developmental oil well completions and for recompletions is estimated at around \$17,183, which includes the costs in Table 3-3 for the REC equipment and transportation in addition to the cost for the completion combustion device. The cost for a completion combustion device alone is estimated to be \$3,723. The cost for addition of REC equipment to a site that is already combusting emissions is estimated to be \$13,459.

For the projected year 2020, applying the cost for the combined REC with completion combustion device to the estimated 5,781 oil wells that are estimated to be capable of conducting a REC, the total nationwide cost was estimated to be approximately \$78.5 million, which includes an estimated annual savings of approximately \$20.8 million when natural gas savings are considered. Likewise, for projected year 2025, the cost for RECs with combustion device applied to 6,144

development oil well completions and recompletions, the total nationwide cost was estimated to be approximately \$83.5 million, including annual savings estimated at around \$22.1 million when natural gas savings are considered.

For development oil wells not capable of conducting a REC due to technical infeasibility, the cost of a REC and combustion control device applied to the 1,156 completions in 2020 and the 1,229 completions in 2025, the nationwide cost was estimated to be approximately \$19.9 million and \$21 million respectively. These completions have no gas savings because the separator is estimated to not be able to function and therefore no gas will be able to be recovered. Finally, for wells that are currently flaring emissions, the EPA estimate 600 wells in 2020 and 637 wells in 2025. The nationwide costs for addition of REC to these completions are approximately \$5.9 million in 2020 and \$6.3 million in 2025 which includes gas savings of approximately \$2.2 million and \$2.3 million, respectively.

For development oil wells that meet the definition of low pressure wells, the standard requires combustion of emissions and a separator is not required to be onsite.<sup>118</sup> Therefore, the EPA apply the cost of a combustion control device to the estimated 4,625 low pressure oil wells estimated for the year 2020 and the estimated 4,915 for the year 2025, the nationwide cost was estimated to be approximately \$17.2 million and \$18.3 million respectively. The total nationwide cost estimated for development oil well completions is approximately \$121.7 million for the year 2020 (including \$23 million in gas savings) and \$129.2 million for the year 2025 (including \$24.4 million in gas savings).

For exploratory and delineation oil well completions, the EPA apply the cost of a combustion control device to the 988 oil well completions estimated for the year 2020 and the 1,083 oil wells estimated for the year 2025, and the nationwide costs associated with exploratory and delineation oil well completions is approximately \$3.7 million for 2020 and \$4 million for 2025. Table 8-4 summarizes the estimated nationwide emission reductions and costs for each of these control scenarios.

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<sup>118</sup> Note that for the final rule the low pressure well definition has been revised. See Appendix A for a full discussion of the revised low pressure well definition.

**Table 8-4. Nationwide Emission and Cost for Control Scenarios under the Final Subpart OOOOa**

Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS <sup>a</sup>	Annual Cost Per Completion Event <sup>b</sup>	Nationwide Emission Reductions <sup>c</sup>				Total Nationwide Costs	
			(tpy)				(\$/year)	
		(\$)	Methane	VOC	HAP	CO2e <sup>d</sup>	without savings	with savings <sup>e</sup>
Projected Year 2020								
Development Oil Wells (Venting/REC with Combustion)	5,781	\$17,183	53,379	44,699	5.3	1,210,611	\$99,333,820	\$78,539,011
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	\$17,183	10,674	8,938	1.1	242,080	\$19,863,327	\$19,863,327
Development Oil Wells (Venting, LP/Combustion)	4,625	\$3,723	42,705	35,761	4.3	968,531	\$17,221,179	\$17,221,179
Development Oil Wells (Flaring/REC)	600	\$13,459	0	0	0	0	\$8,075,587	\$5,917,329
Development Oil Wells (No change)	6,181	\$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	\$3,723	9,123	7,639	0.9	206,899	\$3,678,816	\$3,678,816
Exploratory/Delineation Oil Wells (No change)	372	\$0	0	0	0	0	0	0
Total	19,703	N/A	115,880	97,038	12	2,628,121	148,172,729	125,219,662

Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS <sup>a</sup>	Annual Cost Per Completion Event <sup>b</sup>	Nationwide Emission Reductions <sup>c</sup>				Total Nationwide Costs	
			(tpy)				(\$/year)	
		(\$)	Methane	VOC	HAP	CO2e <sup>d</sup>	without savings	with savings <sup>e</sup>
Projected Year 2025								
Development Oil Wells (Venting/REC with Combustion)	6,144	\$17,183	56,731	47,506	5.7	1,286,627	\$105,571,180	\$83,470,625
Development Oil Wells (Venting/ TI for REC, Combustion)	1,229	\$17,183	11,348	9,503	1.1	257,367	\$21,117,672	\$21,117,672
Development Oil Wells (Venting, LP/Combustion)	4,915	\$3,723	45,383	38,003	4.5	1,029,260	\$18,300,993	\$18,300,993
Development Oil Wells (Flaring/REC)	637	\$13,459	0	0	0	0	\$8,573,581	\$6,282,231
Development Oil Wells (No change)	6,580	\$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	1,083	\$3,723	10,000	8,374	1.0	226,793	\$4,032,548	\$4,032,548
Exploratory/Delineation Oil Wells (No change)	401	\$0	0	0	0	0	0	0
Total	20,989	N/A	123,461	103,386	12	2,800,048	157,595,975	133,204,070

REC = Reduced Emissions Completion, TI for REC, Combustion = Technically infeasible to conduct REC, combustion required, LP = Low pressure wells

a. As presented in Table 4-43.

b. From Table 4-6.

c. Assumes no emission reductions for wells controlled by state regulation in CO, WY, and ND.

d. Assumes 0.90718474 metric tonnes per short ton and global warming potential of methane = 25.

e. Assumes savings only for scenarios where REC is performed.

### **8.3 Nationwide Secondary Impacts**

Regulatory Options 3 and 4 require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although it is understood that the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 3 and 4, it was assumed that 90 percent of flowback is captured and an additional 5 percent of the remaining gas is combusted. For Subcategory 1 oil well completions and recompletions with hydraulic fracturing, it is assumed around 50 Mcf (5 percent of 999 Mcf) of natural gas is combusted on a per well basis when a REC is performed. For Regulatory Option 3 for Subcategory 1 oil wells where combustion is used for control and for Regulatory Option 4 for Subcategory 2 oil well completions and recompletions with hydraulic fracturing, it is assumed that 949 Mcf (95 percent of 999 Mcf) of flowback emissions are combusted by the combustion device. The impacts of pollutant emissions per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 3-5.

For the projected year 2020, for Subcategory 1 well completions and recompletions controlled by a REC combined with a combustion device, it is estimated 0.002 tons of NO<sub>x</sub> are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. For subcategory 1 and subcategory 2 well completions controlled with a combustion device alone, it is estimated 0.37 tons of NO<sub>x</sub> are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions for projected year 2020, the proposed regulatory options are estimated to produce around 300 tons of NO<sub>x</sub> in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 8-5 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2020 and Table 8-6 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2025.

**Table 8-5. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2020<sup>a</sup>**

Pollutant	Regulatory Option 3 <sup>b,c</sup>				Regulatory Option 4 <sup>d</sup>		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	24	0.076	440	0.076	75	540
CO	0.008	54	0.169	975	0.169	167	1,196
NO <sub>x</sub>	0.002	12	0.037	214	0.037	37	262
PM	0.000	0	0.001	7	0.001	1	9
CO <sub>2</sub>	3.599	22,967	71.987	416,155	71.987	71,123	510,246

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Option 3 – REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 5 percent of the flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,381 developmental oil well completions and recompletions using this control scenario.

c. The REC operational standard (Regulatory Option 3 – Combustion) Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 5,781 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 988 exploratory wells fall into this category.

**Table 8-6. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2025<sup>a</sup>**

Pollutant	Regulatory Option 3 <sup>b,c</sup>				Regulatory Option 4 <sup>d</sup>		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	26	0.076	468	0.076	83	576
CO	0.008	57	0.169	1,037	0.169	183	1,2763
NO <sub>x</sub>	0.002	13	0.037	227	0.037	40	280
PM	0.000	0	0.001	8	0.001	1	9
CO <sub>2</sub>	3.599	24,407	71.987	442,287	71.987	77,962	544,655

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Options 3 REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 95 percent of the remaining flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,781 developmental oil well completions and recompletions using this control scenario.

c. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 6,144 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 1,083 exploratory wells fall into this category.

## **9.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS**

### **9.1 Nationwide Emissions from New Sources**

#### *9.1.1 Overview of Approach*

Similar to the approach used to calculate emissions from well site and compressor station model plants, nationwide emissions were calculated by using the model plant emissions that were calculated for the oil and natural well sites and compressor stations. These model plant emissions were used for estimating the baseline emissions and emission reductions for the new sources.

#### *9.1.2 Activity Data*

Data from oil and natural gas technical documents and inventories were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were used to estimate the number of new well sites, gathering and boosting stations, and transmission and storage facilities in 2012. A summary of the steps used to estimate the new sources for each of the oil and gas segments is presented in the following sections.

##### *9.1.2.1 Well Sites*

The DrillingInfo database provided the information on the number of oil and natural gas wells completed or recompleted in the 2012 in the U.S. The total number of new natural gas well completions, both conventional and fractured was determined to be 8,456. From this number of wells, the EPA subtracted wells that were assumed to be covered by state leak regulations as of the effective date of the revised NSPS. Based on our research, four states have recently enacted leak regulations; Colorado, Ohio, Wyoming and Utah. Below is a brief discussion of these state regulations:

- Colorado: Effective on April 14, 2014, requires well production facilities and natural gas compression station owners/operators to inspect components for leaks using an approved instrument monitoring method (AIMM). This LDAR program began as early as January 1, 2015 with inspection frequency varying based on the amount of fugitive VOC emissions identified (i.e., 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly). Monitoring inspections of well production facility and compressor station components must be conducted using Method 21, an infra-red camera, or other Division approved instrument based monitoring devices or methods. In addition, monthly audio, visual, and olfactory inspections must be



conducted to identify leaks. When OGI is used for leak detection, a leak is defined as any detectable emissions that are not associated with normal equipment operation (e.g. pneumatic device actuation)<sup>119</sup>. For compressor station facilities constructed prior to May 1, 2014, a leak is defined as any concentration of hydrocarbon above 2,000 ppm when Method 21 is used to conduct monitoring inspections. For well sites and compressor stations that were constructed on or after May 1, 2014, a leaks is defined as any concentration of hydrocarbon above 500 ppm when Method 21 is used.

- Ohio: On May 19, 2014 Ohio EPA approved two types of oil and gas well-site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing general permits for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT HH). Operators are required to develop and implement a site-specific LDAR program for ancillary equipment (e.g., vent, compressor, PRD, flange, etc.) that requires monitoring using a FLIR camera or Method 21. Quarterly monitoring is required for the first year and varies after that depending on performance.<sup>120</sup> Ohio has also proposed a package of general permits that have been designed around a natural gas compressor station that has the potential to leak greater than 10 tons per year of VOC. The general permit requirements include quarterly monitoring of ancillary equipment, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel using either an OGI or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.
- Utah: On June 5, 2014, Utah Department of Environmental Quality approved a “General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery” on June 5, 2014. This GAO requires LDAR for equipment (e.g., valves, pumps, etc.) at least annually, and initial quarterly surveying of sources with projected annual throughput of crude oil and condensate combined that is greater than 25,000 barrels. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy or an IR camera.<sup>121</sup>

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<sup>119</sup> Colorado regulations available at [https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9\\_0.pdf](https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf).

<sup>120</sup> Ohio regulations available at [http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1\\_PTIOA20140403final.pdf](http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf)  
<http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits>.

<sup>121</sup> Utah regulations are available at <http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf>.

- Wyoming: On June 30, 2015, Wyoming Department of environmental Quality issued regulations for existing (as of January 1, 2014) PAD and single-well oil and gas production facilities that are located in the Upper Green River Basin. The rule regulates fugitive emissions from PAD and single-well facilities or sources, and compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOC and requires owner/operators to develop and implement an LDAR protocol by January 1, 2017. Fugitive emissions monitoring can be conducted using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule - at least one quarterly evaluation must be done using Method 21, OGI, or other instrument based technology. The rule requires quarterly monitoring of control equipment, systems, and devices (e.g. reboiler overhead condensers, storage tanks, vent lines, valves, connectors, etc.).<sup>122</sup>

### 9.1.3 Emission Estimates

The nationwide emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities incrementally affected by the fugitive emission requirements in the NSPS for are summarized in Table 9-1. The summary includes baseline emissions for each of these segments for projected years 2020 and 2025.

**Table 9-1. Nationwide Baseline Emissions for Sources Subject to NSPS Monitoring and Repair Plans in 2020 and 2025**

Oil and Gas Segment	Number of Sources Subject to NSPS <sup>a</sup>	Methane Emissions (tpy)	VOC Emissions (tpy)
<b>Projected Year 2020</b>			
Natural Gas Well Sites	16,819	92,425	25,692
Oil Well Sites (GOR < 300)	32,392	39,989	10,726
Oil Well Sites (GOR > 300)	44,367	122,013	33,382
Gathering & Boosting Stations	480	16,868	4,689
Transmission Stations	20	808	22
Storage Stations	25	3,561	99

<sup>122</sup> Wyoming regulations are available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>.

<b>Oil and Gas Segment</b>	<b>Number of Sources Subject to NSPS<sup>a</sup></b>	<b>Methane Emissions (tpy)</b>	<b>VOC Emissions (tpy)</b>
<b>Projected Year 2025</b>			
Natural Gas Well Sites	34,487	189,515	52,680
Oil Well Sites (GOR < 300)	66,173	81,693	21,912
Oil Well Sites (GOR > 300)	90,636	249,256	68,196
Gathering & Boosting Stations	960	33,737	9,378
Transmission Stations	40	1,616	45
Storage Stations	50	7,122	197

a. Affected facilities in 2020 include new facilities in 2016 through 2020 which are assumed to still be operating in 2020. Affected facilities in 2025 includes new affected facilities in 2016 through 2025 which are assumed to still be operating in 2025.

According to our analysis, 20.87 percent of the total number of new natural gas well completions, both conventional and fractured, were covered by leak regulations in these four states. Therefore the number of new natural gas wells covered by federal regulations was estimated to be 6,691. Assuming an average of two natural gas wells per well site, the number of new well sites in 2012 was estimated to be 3,346. Projections from the NEMS data were used to estimate the total number of new natural gas completions, both conventional and hydraulically fractured in the years 2020 and 2025. The percentage of wells covered by state leak regulations, and the 2 natural gas wells per well site assumptions were applied to these totals to estimate the number of new natural gas production well sites. Our projected activity for year 2020 was developed to reflect the total number of affected facilities in 2020 which is the accumulation of newly affected facilities from 2016 through and including 2020. Likewise, our projected year 2025 reflects total accumulated newly affected facilities from 2016 through and including 2025. These activity estimates assume all newly affected facilities continue to be operating in the projected years. The number of natural gas well sites was estimated to be 16,819 well sites in 2020 and 34,487 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 30 percent of the total natural gas well sites based on a sensitivity analysis of the well site data.

For oil wells, the same approach used for natural gas wells was used to estimate the number of new oil wells in the U.S. The number of new oil well completions in 2012, both conventional and hydraulically fractured, was determined to be 35,404. It was assumed that 8.81 percent of these oil wells are covered by state regulations in 2012 based on information in the HPDI database, which includes: Colorado, Ohio, Wyoming and Utah. Therefore 32,285 new oil wells were not covered by state leak regulations in 2012. Assuming an average of two oil production wells per well site, the number of new oil production well sites

was determined to be 16,142 in 2012. Projections from the NEMS data were used to estimate the total number of new oil well completions in the years 2020 and 2025. The percentage of wells covered by State leak regulations, and the two oil wells per well site assumptions was applied to these totals to estimate the number of new oil well production sites. Because the requirements have impacts annually, our projected activity for years 2020 and 2025 were developed to reflect the facilities newly affected by the rule from 2016 through 2020 and 2016 through 2025, respectively, and assumed to still be in operation in the analysis years. The number of oil well sites were estimated to be 76,759 well sites in 2020 and 156,809 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 43 percent of the total oil well sites based on a sensitivity analysis of the well site data. Oil well sites with a gas-to-oil ratio of greater than 300 were assumed to account for 57.8 percent of the total oil well sites based on data from the HPDI database as summarized in Table 9-1.

#### *9.1.3.1 Gathering and Boosting Stations*

The number of new gathering and boosting stations was estimated using the current number of gathering compressors estimated in the GHG Inventory. The total number of small and large gathering compressors was listed as 36,066 in the inventory. The EPA/GRI document does not include a separate list of individual compressors for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the total number of compressors in the GHG Inventory, the number of gathering and boosting stations was estimated to be 8,015. To estimate the number of new gathering and boosting stations, the EPA used an annual growth rate of 1.2 percent, which is based on the gas well CAGR for new gas wells divided by the average wells per well site. This provided an estimate of 96 new gathering and boosting stations each year that would be affected sources under the proposed NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

#### *9.1.3.2 Transmission and Storage Facilities*

The number of new transmission and storage facilities was estimated by reviewing the annual number of facilities from the year 1990 to 2013 estimated in the GHG Inventory published in 2015 and determining

the rate of change in the number of these facilities over this period. The average change for the last 10 years was reviewed and the annual number of new transmission stations was determined to be 4 and the annual number of storage facilities was determined to be 5. The values were used to estimate the number of affected sources under the NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

#### *9.1.4 Nationwide Impacts of Regulatory Options*

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at production well sites and compressor stations.

##### *9.1.4.1 Primary Environmental Impacts of Regulatory Options*

Based on the discussion above, the EPA reconsidered Regulatory Options 1 and 2 for well sites and Regulatory Options 1, 2 and 3 for compressor stations. A summary of the options are provided below;

- Regulatory Option 1. Require the implementation of a fugitive emissions monitoring and repair program which includes annual monitoring of fugitive emissions components using OGI.
- Regulatory Option 2. Require the implementation of a fugitive emissions monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using OGI.
- Regulatory Option 3. Require the implementation of a fugitive emissions monitoring and repair program which includes quarterly monitoring of fugitive emissions components using OGI.

The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to the regulatory options listed above were estimated using data from the HPDI database. In 2020, which include all new and modified sources since 2016, it was estimated that there would be 76,759 oil well sites, 16,819 gas well sites, 480 gathering and boosting stations, 20 transmission stations, and 25 storage facilities subject to these options. In 2025, which include all new and modified sources since 2016, it was estimated that there would be 156,809 oil well sites, 34,487 gas well sites, 960 gathering and boosting stations, 40 transmission stations, and 50 storage facilities subject to these options.

It was estimated that OGI monitoring and repair can achieve an overall 40 percent VOC and methane reduction for annual monitoring, 60 percent VOC and methane reduction for semiannual monitoring, and 80 percent VOC and methane reduction for quarterly monitoring over the life span of the facility. These percent reduction values were estimated based on information from the EPA white paper and an analysis by the Colorado Air Quality Control Commission as described previously. Nationwide emission reductions were estimated by applying this 40, 60 and 80 percent VOC and methane reduction to the uncontrolled baseline emissions for well sites and compressor stations. In considering the three frequency options, the EPA considered the implementation issues with respect to the monitoring and repair plan and the EPA determined that, based on input from industry and regulatory agencies, that the program frequency should be consistent across the segments in the oil and natural gas source category. Therefore, nationwide impacts were estimated for these options as presented in Tables 9-2, 9-3 and 9-4.

#### *9.1.4.2 Cost Impacts*

##### OGI Monitoring and Repair Plans (Options 1, 2 and 3)

Regulatory Option 1 include annual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-2) include the costs for having a contractor perform the annual OGI survey, activities planning, repair costs, resurvey of repaired components using a Method 21 device, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of an annual OGI monitoring and repair program at well sites was calculated to be 127 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site, 64 Mscf/yr for an oil well site with a GOR > 300, and 29 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas saved was calculated to be 815 Mscf/yr for gathering and boosting stations, 836 Mscf/yr for transmission stations, and 2,950 Mscf/yr for storage facilities.<sup>123</sup>

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue

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<sup>123</sup> Natural gas savings calculated using the CH<sub>4</sub> reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA. Table 9-2 also summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1.

Regulatory Option 2 include semiannual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-3) include the costs for having a contractor perform the semiannual OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas savings from the implementation of a semiannual OGI monitoring and repair program were calculated to be 191 Mscf/yr for a natural gas production well site, 96 Mscf/yr for an oil production well site with a GOR > 300, and 43 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas savings were calculated to be 1,222 Mscf/yr for gathering and boosting stations, 1,255 Mscf/yr for transmission stations, and 4,424 Mscf/yr for storage facilities.<sup>124</sup> Table 9-3 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 2.

Regulatory Option 3 for well sites and compressor stations include quarterly monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-4) include the costs for having a contractor perform the quarterly OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of a quarterly OGI monitoring and repair

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<sup>124</sup> Ibid.

program at well sites was calculated to be 255 Mscf/yr for a natural gas production well site, 127 Mscf/yr for an oil well site with a GOR > 300, and 57 Mscf/yr for an oil production well site with a GOR < 300. The potential natural gas savings at compressor stations were calculated to be 1,629 Mscf/yr for gathering and boosting stations, 1,673 Mscf/yr for transmission stations, and 5,899 Mscf/yr for storage facilities.<sup>125</sup> Table 9-4 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 3.

#### *9.1.4.3 Low Producing Natural Gas and Oil Wells*

For the proposed rule, the EPA evaluated an alternative nationwide impact scenario that accounts for well sites that produce relatively little crude oil and/or natural gas. The EPA had proposed that low producing wells not be subject to fugitive emissions monitoring provisions. While there were several criteria for defining a low-producing well, the EPA believed the definition of a "stripper well" in Internal Revenue Services (IRS) regulations, was consistent with the type of well which would be considered low-producing under that scenario. Under the IRS regulations, a stripper well property "means, with respect to any calendar year, any property with respect to which the amount determined by dividing—(i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by (ii) the number of such wells, is 15 barrel equivalents or less".<sup>126</sup> This proposal was based on our belief at the time that low production wells have inherently low emissions from well completions and that many are owned and operated by small businesses. The EPA was concerned about the burden of the well completion requirement on small businesses, in particular if there is little emission reduction to be achieved.

However, based on information provided in the comments for the proposed rule, the EPA determined that fugitive emissions from low production wells may be comparable to fugitive emissions from other production wells. The low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges, connectors) as production well sites with production greater than 15 boe per day. This indicates that the component counts for low production well sites are similar to that of non-low production well sites, and hence the potential fugitive emissions from both types of well sites are comparable. The comments on the proposed rule stated that many of these well sites are developed for leasing purposes and are typically unmanned and not visited as often as

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<sup>125</sup> Ibid.

<sup>126</sup> 26 U.S.C. 613A(c)(6)(E).



other well sites. This may potentially allow fugitive emissions to go unnoticed longer. No data were provided in the comments on the proposed rule that shows low production well sites have lower GHG (principally as methane) or VOC emissions than normal production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In addition, discussions with the industry indicated that well site fugitive emissions are not based on production, but rather on the number of equipment and components. Therefore, the EPA believes that the emissions from low production and non-low production well sites are likely comparable and are included as affected sources for fugitive emissions.

**Table 9-2. Nationwide Emission and Cost Analysis for Regulatory Option 1 – Annual OGI Monitoring and Repair**

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)	Annual Cost Per Facility (\$)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$1,318	\$809	36,970	10,277	\$22.2	\$13.6
Oil Well Sites (GOR < 300)	32,392	\$1,318	\$1,204	15,996	4,290	\$42.7	\$38.9
Oil Well Sites (GOR > 300)	44,367	\$1,318	\$1,063	48,805	13,353	\$58.5	\$47.2
Well Sites Total	93,578	NA	NA	101,771	27,920	\$123.4	\$99.7
Gathering & Boosting	480	\$7,777	\$4,518	6,747	1,876	\$3.7	\$2.2
Transmission	20	\$10,117	\$6,372	323	9	\$0.2	\$0.1
Storage	25	\$13,798	\$590	1,424	39	\$0.3	\$0.01
Compressor Stations Total	525	NA	NA	8,494	1,924	\$4.2	\$2.3
Projected Year 2025							
Gas Well Sites	34,487	\$1,318	\$809	75,806	21,072	\$45.5	\$27.9
Oil Well Sites (GOR < 300)	66,173	\$1,318	\$1,204	32,677	8,765	\$87.2	\$79.7
Oil Well Sites (GOR > 300)	90,636	\$1,318	\$1,063	99,702	27,278	\$119.5	\$96.4
Well Sites Total	191,296	NA	NA	208,185	57,115	\$252.2	\$204
Gathering & Boosting	960	\$7,777	\$4,518	13,495	3,751	\$7.5	\$4.3
Transmission	40	\$10,117	\$6,372	646	18	\$0.4	\$0.3
Storage	50	\$13,798	\$590	2,849	79	\$0.7	\$0.02
Compressor Stations Total	1,050	NA	NA	16,990	3,848	\$8.6	\$4.6

**Table 9-3. Nationwide Emission and Cost Analysis for Regulatory Option 2 – Semiannual OGI Monitoring and Repair**

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)	Annual Cost Per Facility (\$)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$2,285	\$1,521	55,455	15,415	\$38.4	\$25.6
Oil Well Sites (GOR < 300)	32,392	\$2,285	\$2,114	23,993	6,436	\$74.0	\$68.5
Oil Well Sites (GOR > 300)	44,367	\$2,285	\$1,903	73,208	20,029	\$101.4	\$84.4
Well Sites Total	93,578	NA	NA	152,656	41,880	\$213.8	\$178.5
Gathering & Boosting	480	\$13,534	\$8,646	10,121	2,813	\$6.5	\$4.2
Transmission	20	\$15,868	\$10,250	485	13	\$0.3	\$0.2
Storage	25	\$23,230	\$3,418	2,137	59	\$0.6	\$0.1
Compressor Stations Total	525	NA	NA	12,743	2,885	\$7.4	\$4.5
Projected Year 2025							
Gas Well Sites	34,487	\$2,285	\$1,521	113,709	31,608	\$78.8	\$52.5
Oil Well Sites (GOR < 300)	66,173	\$2,285	\$2,114	49,016	13,147	\$151.2	\$139.9
Oil Well Sites (GOR > 300)	90,636	\$2,285	\$1,903	149,554	40,917	\$207.1	\$172.5
Well Sites Total	191,296	NA	NA	312,279	85,672	\$437.1	\$364.9
Gathering & Boosting	960	\$13,534	\$8,646	20,242	5,627	\$13.0	\$8.3
Transmission	40	\$15,868	\$10,250	969	27	\$0.6	\$0.4
Storage	50	\$23,230	\$3,418	4,273	118	\$1.2	\$0.2
Compressor Stations Total	1,050	NA	NA	25,484	5,772	\$14.8	\$8.9

**Table 9-4. Nationwide Emission and Cost Analysis for Regulatory Option 3 – Quarterly OGI Monitoring and Repair**

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility (\$)		Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million \$/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	\$4,220	\$3,201	73,940	20,553	\$70.9	\$53.8
Oil Well Sites (GOR < 300)	32,392	\$4,220	\$3,991	31,991	8,581	\$136.7	\$129.3
Oil Well Sites (GOR > 300)	44,367	\$4,220	\$3,710	97,610	26,706	\$187.2	\$164.6
Well Sites Total	93,578	NA	NA	203,541	55,840	\$394.8	\$347.7
Gathering & Boosting	480	\$25,049	\$18,532	13,495	3,751	\$12.0	\$8.9
Transmission	20	\$27,369	\$19,879	646	18	\$0.5	\$0.4
Storage	25	\$42,093	\$15,678	2,849	79	\$1.1	\$0.4
Compressor Stations Total	525	NA	NA	16,990	3,848	\$13.6	\$9.7
Projected Year 2025							
Gas Well Sites	34,487	\$4,220	\$3,201	151,612	42,144	\$145.5	\$110.4
Oil Well Sites (GOR < 300)	66,173	\$4,220	\$3,991	65,354	17,530	\$279.2	\$264.0
Oil Well Sites (GOR > 300)	90,636	\$4,220	\$3,710	199,405	54,557	\$382.4	\$336.2
Well Sites Total	191,296	NA	NA	416,371	114,231	\$807.1	\$710.6
Gathering & Boosting	960	\$25,049	\$18,532	26,989	7,502	\$24.0	\$17.8
Transmission	40	\$27,369	\$19,879	1,293	36	\$1.1	\$0.8
Storage	50	\$42,093	\$15,678	5,698	158	\$2.1	\$0.8
Compressor Stations Total	1,050	NA	NA	33,980	7,696	\$27.2	\$19.4

## **10.0 NATIONWIDE IMPACTS FOR PNEUMATIC CONTROLLERS**

### **10.1 Nationwide Emissions from New Sources**

#### *10.1.1 Approach*

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined using the methodologies described in section 10.1.2 of this chapter.

#### *10.1.2 Population of Controllers Installed Annually*

The number of pneumatic controllers installed in the transmission and storage segment was approximated using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given years total (e.g., 2012). This difference was assumed to be the number of new devices installed in the latter year (e.g., Number of new devices installed during 2012 equals pneumatics in 2012 minus pneumatics in 2011). A 10-year average was calculated based on the number of new controllers installed in 2003 through 2012 in order to determine the average number of new devices installed in a typical year. An average was taken of all years. Where the year change was negative, the average calculation treated it as zero.

The number of facilities estimated to be subject to regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low-bleed controllers, such as in Wyoming and Colorado. Therefore, the EPA considered all facilities to be unregulated for this analysis.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of intermittent controllers that would be installed versus a bleed controller. This estimate of the percent of intermittent and bleed controllers was based on data from the GRI study, where 32 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission and

storage segment.<sup>127</sup> The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 10-1 summarizes the estimated number of new devices installed per year.

**Table 10-1. Estimated Number of Pneumatic Controllers Installed in a Typical Year in the Natural Gas Transmission and Storage Segment**

Number of New Controllers Estimated for a Typical Year <sup>a, b</sup>		
Intermittent	Bleed-Devices	Total
256	120	376

a. National averages of population counts from the Inventory were refined to include the difference in intermittent and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 32 percent of the pneumatic controllers are bleed devices in the transmission and storage segment.

b. The number of pneumatics controllers estimated for the transmission and storage segment was approximated from comparing a 10 year average of new controllers installed in 2003 through 2012 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012.

### 10.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 10-2. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table W-3 of the GHG Reporting Rule, Subpart W since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

**Table 10-2. Nationwide Baseline Emissions from Representative Pneumatic Controller Installed in a Typical Year in Natural Gas Transmission and Storage Segment<sup>a, b</sup>**

Baseline Emissions from Representative New Continuous Bleed Controller (tpy)		Number of New Continuous Bleed Controllers Expected Per Year	Nationwide Baseline Emissions from New Continuous Bleed Controller (tpy)	
Methane	VOC		Methane	VOC
3.013	0.083	120	362	10

a. Baseline emissions were based on the bleed rates for a high-bleed controllers.

b. To estimate VOC emissions, the weight ratio of 0.0277 lbs VOC per pound methane was used.

## 10.2 Nationwide Cost Impacts of Regulatory Options

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective,

<sup>127</sup> See footnote 57.

however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Table 10-3 summarizes the nationwide emission reductions and nationwide costs impacts of the selected regulatory option for the natural gas transmission and storage segment. It is estimated to affect 96 new transmission and storage pneumatic controllers per year and 480 new affected sources through 2020 and 960 affected sources through 2025. The nationwide capital cost for projected year 2020 is estimated to be \$109,073 and annual costs of \$11,976 without considering value of gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2020 is a net savings of \$270,264. The nationwide capital cost for projected year 2025 is estimated to be \$218,146 and annual costs of \$23,951 without considering savings from gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2025 is a net savings of \$540,529.

**Table 10-3. Nationwide Cost and Emission Reduction Impacts for Pneumatic Controllers for Transmission and Storage for the Projected Years 2020 and 2025**

Number of Affected Facilities <sup>a</sup>	Capital Cost Per Controller <sup>b</sup>	Annual Costs		Nationwide Emission Reductions				Total Nationwide Costs (\$/year)		
		w/o savings	w/savings	(tpy)			(metric tonnes)	Capital Cost	Annualized Cost	
	(2012)	(\$/year)		Methane	VOC	HAP	CO2e		w/o savings	w/savings
Projected Year 2020										
480	\$227	\$25	(\$563)	1,338	37	1	30,335	\$109,073	\$11,976	(\$270,264)
Projected Year 2025										
960	\$227	\$25	(\$563)	2,675	74	2	60,671	\$218,146	\$23,951	(\$540,529)

a. The number of sources subject to NSPS for the natural gas transmission and storage segment represent the number of new controllers expected per year (120) reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed controllers can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments.

b. The capital cost is equal to the incremental cost of a low bleed device versus a new high bleed device.

c. Based on the global potential warming of methane equal to 25.

Note: Negative numbers reflect a net savings.



## 11.0 NATIONWIDE IMPACTS FOR PNEUMATIC PUMPS

### 11.1 Nationwide Emissions from New Sources

#### 11.1.1 Approach

Nationwide emissions from newly installed natural gas pneumatic pumps for a typical year were calculated by estimating the count of pneumatic pumps installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 6-2. The count of new pneumatic pumps installed for a typical year was determined for each natural gas production and natural gas processing. The methodologies that determined the estimated count of new pneumatic pumps installed in a typical year is provided below.

#### 11.1.2 Population of Pneumatic Pumps Installed Annually

For the natural gas production segment the count of new pneumatic pumps installed in a typical year was estimated by reviewing the annual count of pneumatic pumps from the year 1990 to 2012 reported in the GHG Inventory for the natural gas and oil production facilities and determining the rate of change in the count of pneumatic pumps in each inventory over this period. For all the years, the annual counts of new pneumatic pumps installed between two years were not consistent. The average change for the entire period was estimated to be 877 for natural gas facilities and (-161) for oil facilities. Additionally, the average change over the last 10 years was estimated to be 1,480 for natural gas facilities and 803 for oil facilities. Because of the fluctuation in the count of new pneumatic pumps from the years 1990 to 2012, it was assumed that the 10-year average change represented a better estimate of the current growth of pneumatic pumps. For proposal the EPA calculated the average change excluding years where there was a negative change in the number of pneumatic pumps IPs. Based on comments received, the EPA changed the methodology to include the years where there was a negative change as zero in the averaging calculation. Based on this methodology, the counts of new pneumatic pumps that would be affected sources under the proposed NSPS for a typical year was estimated to be 1,184 for natural gas facilities and 241 for oil facilities.

To forecast the count of pneumatic pumps replaced in a *typical* year, age and count of gas and oil wells for 2012 were extracted from DI Desktop®. The age of the pneumatic pump was assumed to be the age of the well. The average lifetime of a pneumatic pump was assumed to be 10 years. Therefore, a portion of CIPs that reached 10 years in a particular year were assumed to be replaced that year. For a typical year for this analysis, the replacement count for pneumatic pumps was estimated to be 340

diaphragm pumps and 340 piston pumps for gas wells with the same replacement pump counts for oil wells.

The GHG Inventory<sup>128</sup> does not estimate any emissions from pneumatic pumps for the natural gas processing, natural gas transmission and storage segments. Pneumatic pump data are not reported in GHGRP for these segments. For this analysis, the EPA assumed that pneumatic pumps are not used in these segments.

Once the population counts of pneumatic pumps in each segment were established, the count of pneumatic pumps was split into diaphragm and piston. Similar to the assumption used in the EPA/GRI Report,<sup>129</sup> for new and replaced pumps for each segment the EPA assumed 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps. Table 11-1 below summarizes the estimated count of new pumps installed per year.

**Table 11-1. Estimated Count of Pneumatic Pumps Installed in a Typical Year**

Segment/Pump Type	Number of New Pumps
Production/Diaphragm	1,052
Production/Piston	1,052
Processing/Diaphragm and Piston	0
Transmission/Diaphragm and Piston	0
Storage/Diaphragm and Piston	0

### 11.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic pumps for new sources in a typical year are summarized in Table 11-2 by industry segment and pump type.

<sup>128</sup> See footnote 81.

<sup>129</sup> See footnote 82.

**Table 11-2. Nationwide Baseline Emissions from Representative Pneumatic Pumps Installed in a Typical Year for the Oil and Natural Gas Industry**

Segment/Pump Type	Number of New Pumps <sup>a</sup>	Emission Factor (tpy) <sup>b</sup>		Nationwide Emissions (tpy)	
		Methane	VOC	Methane	VOC
Production/Diaphragm	1,052	3.46	0.96	3,641	1,012
Production/Piston	1,052	0.38	0.11	400	111
Processing/Diaphragm	0	3.46	0.96	0	0
Processing/Piston	0	0.38	0.11	0	0
Totals				4,040	1,123
Total Production				4,040	1,123
Total Processing				0	0
Total Transmission				0	0
Total Storage				0	0

a. From Table 7-3.

b. From Table 7-2.

## 11.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

The EPA calculated the nationwide impacts of the selected options by considering the estimated affected population for each of the target years, the estimated emission reductions per pneumatic pump controlled by the regulatory option and the annualized cost associated with that control option for that pump in that segment.

For Option 1, based on the activity analysis presented above, the EPA estimated there will be no new pneumatic pumps installed in the natural gas processing segment in either of the projected years 2020 or 2025. Therefore, there will be zero nationwide emission reductions and costs associated with Option 1.

For Option 3 for the final rule, the EPA estimated that there will be 1,052 new, modified, or reconstructed diaphragm pumps installed in a typical year. As noted above, due to inherently low emissions, piston pumps were removed from coverage under the final rule. In addition, for the final rule, the EPA included a provision that allowed for an exemption from control where it is determined to be technically infeasible to connect the pump to an existing control device or process at a non-greenfield site or where the a pump is limited use. The EPA has no data that provides information on the number of pumps located at sites where a control device or process is available. Further, the EPA have no data that indicates how often conditions with respect to the pump and/or the control device would be such that it would be technically infeasible to connect the pump to an existing control device or process or where a pump is limited use. In order to estimate impacts that account for these circumstances that would remove

control requirements for the pumps under the NSPS, the EPA has estimated that 75 percent of the new pumps will be able to be connect to an existing control device or process. Based on this estimate, 789 pumps in a typical year would be subject to control requirements under the rule.

For nationwide impacts, the EPA estimated that a total of 3,946 new or replaced diaphragm pumps will be installed in the production segment from 2016 through and including the projected year 2020, assumed to still be in operation in 2020. For the projected year 2025, the EPA determined the affected population as those affected facilities from the years 2016 through and including 2025, assumed to still be in operation in 2025. Therefore, the EPA estimated that 7,892 new diaphragm pumps will be installed in the production segment by 2025. Table 12-3 summarizes the estimated number of pumps that would be subject to the final rule provisions for the projected years 2020 and 2025.

**Table 11-3. Estimated Count of Pneumatic Pumps Installed Subject to NSPS for 2020 and 2025**

Segment/Pump Type	Estimated Number of New Pumps			
	Pumps Per Year <sup>a</sup>	Controlled Per Year Under NSPS	Controlled Under NSPS 2020	Controlled Under NSPS 2025
Production/Diaphragm	1,052	789	3,946	7,892
Production/Piston	1,052	0	0	0
Processing/Diaphragm and Piston	0	0	0	0

a. This number includes all newly installed, modified, and reconstructed pumps.

Based on these activity numbers, the nationwide emission reductions in 2020 are estimated to be 12,970 tons per year of methane and 3,605 tons per year of VOC from diaphragm pumps. The total nationwide emission reductions, for the projected year 2025, are estimated to be 25,940 tons per year of methane and 7,210 tons per year of VOC from diaphragm pumps.

The nationwide costs are based only on the Option 3 costs related to routing pump emissions to an existing combustion device or a VRU. The EPA estimated that the annualized cost for routing pump emissions either to a combustion device or a VRU would be \$774. Based on the estimated affected population of 3,946 pneumatic pumps in 2020, the EPA estimated the nationwide cost to be approximately \$3.1 million in 2020. The nationwide costs are estimated to be approximately \$6.1 million in 2025. Table 11-4 summarizes the nationwide emission reduction and cost impacts for projected years 2020 and 2025.

Secondary emissions impacts for Option 3 would include emissions resulting from the combustion of the recovered gas. Table 11-5 summarizes the nationwide secondary emissions for the projected year 2020 and 2025 for Option 3.

**Table 11-4. Nationwide Impacts for Gas-Driven Diaphragm Pumps for Projected Years 2020 and 2025**

Segment/ Affected Facility	Number of Pumps Subject to NSPS <sup>a</sup>	Annualized Cost <sup>b</sup>	Nationwide Emission Reductions <sup>c</sup>				Nationwide Costs
			(tpy)			(metric (tonnes) <sup>d</sup>	
		(\$)	Methane	VOC	HAP	CO <sub>2</sub> e	(million \$)
Projected Year 2020							
Natural Gas Processing	0	\$10,051 - \$72,394	0	0	0	0	\$0
Production	3,946	\$774	12,970	3,605	136	294,149	\$3.1
Projected Year 2025							
Natural Gas Processing	0	\$10,051 - \$72,394	0	0	0	0	\$0
Production	7,892	\$774	25,940	7,210	272	588,299	\$6.1

a. From Table 7-19.

b. From Table 7-18.

c. Based on 95 percent control.

d. Assumes 0.90718474 metric tonnes per short ton and global warming potential of methane = 25.

**Table 11-5. Nationwide Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device for Projected Years 2020 and 2025**

Segment	Secondary Impacts (tpy)				
	THC <sup>a</sup>	CO <sup>b</sup>	CO <sub>2</sub> <sup>c</sup>	NO <sub>x</sub> <sup>d</sup>	PM <sup>e</sup>
<b>Projected Year 2020</b>					
Production	60	133	56,699	292	1
<b>Projected Year 2025</b>					
Production	120	266	113,397	58	0

a. Total hydrocarbons - based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Carbon monoxide - based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Carbon Dioxide - based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Nitrous Oxides - based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Particulate Matter - based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

## 12.0 NATIONWIDE IMPACTS FOR COMPRESSORS

### 12.1 Nationwide Emissions from New Sources

#### 12.1.1 Overview of Approach

The number of new affected facilities in the oil and natural gas source category was estimated using data from the GHG Inventory.<sup>130</sup> The nationwide emissions estimates for new sources were then determined by multiplying the number of new sources for each oil and natural gas segment by the expected emissions per compressor based on the emission factor data presented in Table 7-3. A summary of the number of new, modified, and reconstructed reciprocating and centrifugal compressors for transmission and storage segment is presented in Table 7-4.

#### 12.1.2 Nationwide Activity Data for Compressors in Transmission and Storage

The number of reciprocating compressors and wet seal centrifugal compressors installed in the transmission and storage segment was estimated using the GHG Inventory. The number of new reciprocating compressors, wet seal centrifugal compressors, and dry seal centrifugal compressors installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given year's (e.g., 2012) total as represented in the Inventory. This difference was assumed to be the number of new compressors installed in the latter year (e.g., number of new compressors installed during 2012 equals the compressors reported in 2012 minus the compressors reported in 2011). A 10-year average was calculated based on the number of new compressors installed in 2003 through 2012 in order to determine the average number of new compressors installed in a typical year. Where the data indicated a decrease in new compressors, the average calculation counted those years as zero. An average was taken of all years and rounded to the nearest whole number. The results of this analysis are shown in Table 12-1.

**Table 12-1. Approximate Number of New Compressors in the Transmission and Storage Segment in a Typical Year<sup>a</sup>**

Compressor Location	Number of New Reciprocating Compressors	Number of New Centrifugal Compressors	
		Wet Seal	Dry Seal
Transmission	15	0	2
Storage	17	1	5

<sup>130</sup> See footnote 4.

a. Estimates of the number of new compressors were rounded to the nearest whole number.

### 12.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 12-2 by industry segment.

**Table 12-2. Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors for Projected Years 202 and 2025**

Compressor Location/Compressor Type	Nationwide Baseline Emissions (tpy)	
	Methane	VOC
<b>Projected Year 2020</b>		
<b>Transmission</b>		
Reciprocating Compressors	2,035	56
Wet Seal Centrifugal Compressors	0	0
<b>Storage</b>		
Reciprocating Compressors	2,401	675
Wet Seal Centrifugal Compressors	585	16
<b>Projected Year 2025</b>		
<b>Transmission</b>		
Reciprocating Compressors	4,070	113
Wet Seal Centrifugal Compressors	0	0
<b>Storage</b>		
Reciprocating Compressors	,4802	133
Wet Seal Centrifugal Compressors	1,169	32

## 12.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

Tables 12-3 and 12-4 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 15 reciprocating compressors at transmission facilities and 17 reciprocating compressors at underground storage facilities in a typical year. The nationwide impacts for projected year 2020 are based on a typical year. The projected affected number of compressors for projected year 2020 is calculated as all compressors affected from 2016 through and including 2020 and for 2025 as all compressors affected from 2016 through and including 2025, assumed to still be in operation in the analysis years. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-3.

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation

service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Regulatory Option 3 is expected to affect 1 new wet-seal centrifugal compressor in the transmission and storage segment (specifically at a storage facility) each year. The number of affected centrifugal compressors is low because the historical rate of growth in the overall number of wet seal centrifugal compressors in the segment has been low, indicating few new compressors are being installed. In addition, most new centrifugal compressors are expected to use dry seals, which would not be affected facilities. EPA did not change these activity numbers for the final rule. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-4. A summary of the nationwide secondary combustion-related emissions from Option 2 are summarized in Table 12-5.



**Table 12-3. Nationwide Cost Impacts for Regulatory Option 1**

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Total Nationwide Costs	Annualized Cost (\$/year)	
		Methane	VOC	Capital Cost (\$)	Without Savings	With Savings
Projected Year 2020						
Transmission	75	1,626	45	\$423,769	\$131,066	(\$205,534)
Storage	85	1,856	51	\$654,915	\$159,594	(\$207,676)
Projected Year 2025						
Transmission	150	3,252	90	\$847,537	\$262,132	(\$411,068)
Storage	170	3,712	103	\$1,309,830	\$353,049	(\$415,351)

Note: Negative number indicates net savings.

**Table 12-4. Nationwide Cost Impacts for Regulatory Option 3**

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Nationwide Costs			
		Methane	VOC	Capital Cost New CD <sup>a</sup> (\$)	Capital Cost Existing CD <sup>b</sup> (\$)	Annual Cost New CD <sup>a</sup> (\$/year)	Annual Cost Existing CD <sup>b</sup> (\$/year)
Projected Year 2020							
Transmission	0	0	0	\$0	\$0	\$0	\$0
Storage	5	555	21	\$358,914	\$116,260	\$570,728	\$16,553
Projected Year 2025							
Transmission	0	0	0	\$0	\$0	\$0	\$0
Storage	10	1,111	41	\$717,829	\$232,520	\$1,141,456	\$33,106

a. CD = Combustion Device Cost is based installation of a full system of control using a combustion device.

b. Cost is based on routing compressor to an existing combustion device.

**Table 12-5. Nationwide Secondary Impacts from Compressor Emissions Routed to a Combustion Device**

Compressor Location	Secondary Impacts (tpy)				
	THC <sup>a</sup>	CO <sup>b</sup>	CO <sub>2</sub> <sup>c</sup>	NO <sub>x</sub> <sup>d</sup>	PM <sup>e</sup>
<b>Projected Year 2020</b>					
Storage	2.9	6.4	2,748	1.4	0.05
<b>Projected Year 2025</b>					
Storage	5.8	13	5,496	2.8	0.10

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.

b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.

c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.

d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.

e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a “lightly smoking” flare.

## 13.0 NATURAL GAS SAVINGS

Affected facilities under the NSPS may recover natural that would have otherwise been vented or combusted as a result of controlling emissions. This section presents the value of recovered gas nationally.<sup>131</sup> With respect to the regulatory options presented above, there are several opportunities for gas savings to be realized, as noted below:

- For oil well completions, with implementation of a REC, the EPA estimated that 899 Mcf of natural gas is recovered during the average 3-day completion event.
- For equipment leaks, with implementation of the semiannual OGI monitoring and repair of leaks found, the EPA estimate that the average annual gas saved would be 43 Mcf for oil wells with GOR < 300, 96 Mcf for oil wells with GOR > 300, 191 Mcf for gas wells, 1,222 Mcf for gathering and boosting stations, 1,255 Mcf for transmission stations, and 4,424 for storage facilities. For quarterly monitoring and repair, the EPA estimate for average annual gas saved would be 57 Mcf for oil wells with GOR < 300, 127 Mcf for oil wells with GOR > 300, 255 Mcf for gas wells, 1,629 Mcf for gathering and boosting stations, 1,673 Mcf for transmission stations, and 5,899 for storage facilities.
- For pneumatic controllers, the EPA estimate the use of low-bleed controllers instead of high-bleed controllers will save 147 Mcf of natural gas per year.
- For reciprocating compressors, the EPA estimate that the replacement of rod packing every 26,000 hours of operations (or every three years) will avoid the loss of, for each reciprocating compressor, 1,122 Mcf per year for transmission facilities and 1,130 Mcf per year for storage facilities.<sup>132</sup>
- For centrifugal compressors, the EPA estimates that the replacement of one wet seal compressor with a dry seal compressor will save 5,290 Mcf per year.<sup>133</sup>

Based on the above per unit natural gas savings and the new source activity counts anticipated for the projected years 2020 and 2025 for the affected facilities, the EPA calculated

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<sup>131</sup> Note that operators in the gathering and boosting and transmission and storage segments of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost supporting BSER decisions in the preamble (and is presented in Volume 1 of this TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. This section addresses all gas savings regardless of presumed ownership.

<sup>132</sup> See footnote 2.

<sup>133</sup> See footnote 2.

the nationwide gas savings for each of the regulatory options discussed in the sections above for the projected years 2020 and 2025. Table 13-1 presents the estimated gas savings for these affected facilities.

**Table 13-1. Estimated Nationwide Natural Gas Savings for Selected Regulatory Options**

Affected Facility	Number of Affected Facilities Subject to NSPS <sup>a</sup>	Volume of Gas Saved (MMcf)	Value of Gas Saved (\$ million)
<b>Projected Year 2020</b>			
<i>Well Completions</i>			
Development Oil Wells	19,703	5,738	\$23
<i>Equipment Leaks</i>			
Oil Well Site <sup>b</sup>	76,759	5,633	\$22.5
Gas Well Site <sup>b</sup>	16,819	3,214	\$12.9
Gathering <sup>c</sup>	480	782	\$3.1
Transmission <sup>c</sup>	20	33	\$0.13
Storage <sup>c</sup>	25	147	\$0.59
Pneumatic Controllers	480	70.6	\$0.28
Pneumatic Pumps	3,946	0	\$0.00
Reciprocating Compressors - Transmission	75	84	\$0.34
Reciprocating Compressors - Storage	85	96	\$0.38
Centrifugal Compressors - Storage	5	26	\$0.10
Total Projected Year 2020	122,343	15,824	\$63
<b>Projected Year 2025</b>			
<i>Well Completions</i>			
Development Oil Wells	20,988	6,098	\$24.4
<i>Equipment Leaks</i>			
Oil Well Site	156,809	11,508	\$46
Gas Well Site	34,487	6,590	\$26.4
Gathering	960	1,564	\$6.3
Transmission	40	67	\$0.27
Storage	50	295	\$1.8
Pneumatic Controllers	960	141	\$0.56
Pneumatic Pumps	7,892	0	\$0
Reciprocating Compressors - Transmission	150	168	\$0.67
Reciprocating Compressors - Storage	170	192	\$0.77
Centrifugal Compressors - Storage	10	53	\$0.21
Total Projected Year 2025	230,407	26,676	\$107

a. Reflects only the number of affected facilities subject to the NSPS that will have potential gas savings (not all sources will have potential for gas savings).

b. For oil wells, the activity number reflects both oil well sites with GOR < 300 and oil well sites with GOR > 300. The gas savings for well sites are based on semiannual monitoring and repair.

c. The gas savings for compressor stations are based on quarterly monitoring and repair.

## 14.0 POTENTIAL NATIONWIDE CO<sub>2</sub> Eq. and HAP IMPACTS

Because methane is of concern for global warming effects, the EPA also calculated the global warming potential expressed as CO<sub>2</sub> Eq. for the methane reductions from the proposed regulatory options. For the purposes of this analysis, one ton of methane is equal to 25 tons of CO<sub>2</sub> Eq. The EPA have converted the CO<sub>2</sub> Eq. values to metric tonnes consistent with the presentation of CO<sub>2</sub> Eq. in the GHG Inventory.

In addition, there may be important HAP emission co-reductions a resulting from the application of emission controls under the NSPS. For the purposes of the NSPS, the EPA estimate HAP emissions by applying a ratio to the methane emissions. The ratio used is based on the gas composition analysis conducted for the NSPS.<sup>134</sup> Because gas composition was determined to vary between industry segments and between the various affected facilities, different ratios were used accordingly. Table 14-1 summarizes the HAP-to-methane ratios used for the various affected facilities in the various segments. Based on the methane emission reductions estimated in the above sections for the respective affected facilities and regulatory options, the EPA estimated the HAP emissions.

Table 14-2 summarizes the CO<sub>2</sub> Eq. and HAP emission reductions calculated for the affected facilities based on the finalized regulatory options.

**Table 14-1. HAP-to-Methane Ratios Used to Estimate HAP Emissions**

Segment	Affected Facility	HAP-to-Methane Ratio
Production	HF Oil Well Completions	0.0001
	Equipment Leaks:	
	Oil Well sites	0.0105
	Gas Well Sites	0.0105
	Gathering and Boosting	0.0105
Transmission	Pneumatic Pumps	0.0105
	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
Storage	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
	Centrifugal Compressor	0.000822

<sup>134</sup> See footnote 3.

**Table 14-2. HAP and CO<sub>2</sub> Eq. Reductions for Selected Regulatory Options**

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO <sub>2</sub> e (MT/year)
Projected Year 2020					
HF Oil Well Completions					
All Oil Wells	19,703	115,880	97,038	12	2,628,121
Development Oil Wells	18,955	106,758	89,399	11	2,421,222
Exploratory/Delineation Oil Wells	748	9,123	7,639	1	206,899
Equipment Leaks					
Oil Well Site	76,759	97,201	26,465	997	2,204,483
Gas Well Site	16,819	55,455	15,415	581	1,257,695
Gathering & Boosting	480	13,495	3,751	141	306,056
Transmission	20	646	18	0.5	14,657
Storage	25	2,849	79	2.3	64,609
Pneumatic Controllers	480	1,338	37	1	30,335
Pneumatic Pumps	3,946	12,970	3,605	136	294,149
Reciprocating Compressors					
Transmission	75	1,626	45	1.3	36,881
Storage	85	1,856	51	1.5	42,094
Centrifugal Compressors – Storage	5	555	15	0.4	23,178
Total Projected Year 2020	118,397	303,871	146,519	1,874	6,902,258
Projected Year 2025					
HF Oil Well Completions					
All Oil Wells	20,988	123,461	103,386	12	2,800,048
Development Oil Wells	20,191	113,461	95,012	11	2,573,255
Exploratory/Delineation Oil Wells	797	10,000	8,374	1	226,793
Equipment Leaks					
Oil Well Site	156,809	198,569	54,065	2,037	4,503,477
Gas Well Site	34,487	113,709	31,608	1,191	2,578,877
Gathering	960	26,989	7,502	283	612,111

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO <sub>2</sub> e (MT/year)
Transmission	40	1,293	36	1.1	29,314
Storage	50	5,698	158	4.7	129,218
Pneumatic Controllers	960	2,675	74	2	60,671
Pneumatic Pumps	7,892	25,940	7,210	272	588,299
<i>Reciprocating Compressors</i>					
Transmission	150	3,252	90	2.6	73,762
Storage	170	3,712	103	3.0	84,187
<i>Centrifugal Compressors</i>					
Storage	10	1,111	31	1	25,187
Total Projected Year 2025	222,516	506,409	204,263	3,810	11,485,151

## **15.0 COMPARISON OF TOTAL COST IMPACTS TO OVERALL INDUSTRY CAPITAL EXPENDITURES AND RECEIPTS**

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of BSER for the final standards as presented in Volume 1 of this TSD, we analyzed the total cost of the rule for each type of affected facility (as presented in Volume 2 of this TSD) under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the final standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the final standards to the level of new capital expenditures that the industry is incurring in the absence of the final standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey<sup>135</sup>. For the capital expenditures analysis, we determined the estimated nationwide capital costs estimated to be incurred by each type of affected facility to comply with the final standards<sup>136</sup>, then divided the nationwide capital costs by the new capital expenditures (census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICs codes that correspond to oil and natural gas production segment. Table 15-1 below summarizes the capital expenditure data used for our analysis.

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. Instead, for the purposes of this portion of the analysis, we used the first-year corporate-based costs for these standards.

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<sup>135</sup> Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See [http://www.census.gov/econ/aces/xls/2013/full\\_report.html](http://www.census.gov/econ/aces/xls/2013/full_report.html)

<sup>136</sup> The total capital cost estimate is based on the number of estimated affected facilities within the year and the capital cost per facility, however, the capital expenditure may not actually be incurred in that year.



In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to determine whether the annualized costs appear reasonable as a percentage of the revenues being generated by the industry. The annualized cost, as calculated for the rule, includes capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We included, where applicable, the cost savings realized from recovered natural gas. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census<sup>137</sup>. For the annual revenues analysis, we determined the estimated nationwide annualized costs incurred by each type of affected facility to comply with the final standards<sup>138</sup>, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICS codes that correspond to oil and natural gas production segment. Table 15-2 below summarizes the revenue data used for our analysis.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline transportation of natural gas". Although there is not a one-to-one correspondence between NAICS codes and the

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<sup>137</sup> Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see <http://www.census.gov/econ/susb/methodology.html>. For definitions of estimated receipts and other definitions, see <http://www.census.gov/econ/susb/definitions.html>.

<sup>138</sup> The estimated nationwide annualized costs were determined based on the estimated number of affected facilities in that year, however, these annualized costs are not necessarily incurred within that same year.

industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware the different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 15-3 summarizes the result of our analysis. In all cases we found that the rule impacts in comparison to either capital expenditures or revenues represent a fraction of one percent.

**Table 15-1. NAICS-Based Capital Expenditure Data**

<b>Capital Expenditures Data (millions \$, current\$)</b>			
<b>Oil and Natural Gas Segment</b>	<b>NAICS code</b>	<b>NAICS DESCRIPTION</b>	<b>Total New Expenditures</b>
Production	2111	Crude Petroleum and Natural Gas Extraction	\$158,911
	213111 213112	Support activities for oil and gas operations	\$19,966
	4862	Pipeline transportation of natural gas	\$12,891
Transmission and Storage			

**Table 15-2. NAICS-Based Revenue Data**

<b>Revenue Data (millions \$, 2012\$)</b>				
<b>Oil and Natural Gas Segment</b>	<b>NAICS CODE</b>	<b>NAICS DESCRIPTION</b>	<b>ESTIMATED RECEIPTS (\$1,000)</b>	<b>ESTIMATED RECEIPTS (millions 2012\$)</b>
Production	211111	Crude Petroleum and Natural Gas Extraction	\$276,076,578	\$276,077
	213112	Support Activities for Oil and Gas Operations	\$90,645,566	\$90,646
Processing	211112	Natural Gas Liquid Extraction	\$49,236,136	\$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	\$26,587,330	\$26,587

**Table 15-3. Comparison of Final NSPS OOOOa Nationwide Cost in 2025, by Affected Facility Cost to Industry Wide Capital Expenditures and Revenues**

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs	Total Nationwide Annual Cost	Nationwide Capital Cost/ Capital Expenditures	Nationwide Annual Cost/Receipts
	Units	(million 2012\$)	(million \$)	(%)	(%)
<i>Production</i>					
Hydraulically Fractured Oil Well Completions and Re Completions	21,000	160	130	0.09	0.04
Pneumatic Pumps	8,000	43	6.1	0.02	0.00
Fugitives - Well Sites	190,000	150	365	0.09	0.10
<b>Total Production Segment</b>	219,000	353	501	0.20	0.14
<i>Transmission and Storage</i>					
Compressors					
- Reciprocating	320	2	1	0.02	0.00
- Centrifugal	10	\$1.1	1	0.06	0.04
Pneumatic Controllers	960	0	0	0.00	0.00
Fugitives - Compressor Stations	1,100	4	27	0.03	0.10
<b>Total Transmission and Storage Segment</b>	2,400	7	29	0.11	0.14

Source : All cost information is from the "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Re Completions from Table 8-4, for Gas Driven Pumps from Table 11-4, for Fugitives - Well sites from Table 9-3, for Compressors, Reciprocating from Table 12-3, for Centrifugal from Table 12-4, for Pneumatic controllers from- Table 10-3, and for Fugitives - Compressor Stations from Table 9-4. The analysis results are rounded to two significant digits for this presentation. Capital costs reflect capital costs associated with affected facilities in 2025, including expenditures made prior to 2025.

## **APPENDIX A**

### **MEMORANDUM**

Development of the Low Pressure Well Equation for Determining REC Requirements at  
Hydraulically Fractured Oil and Gas Wells



## MEMORANDUM

FROM: ICF International

THRU: Graham Fitzsimons, EC/R

TO: Ravi Srivastava, U.S. EPA

DATE: April 29, 2016

SUBJECT: Technical Development of the Low Pressure Well Equation for Assessing REC Feasibility at Hydraulically Fractured Oil and Gas Wells

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This memorandum documents the method for estimating flowback pressure during completion for a hydraulically fractured petroleum well to assess whether a Reduced Emissions Completion (REC) can be implemented. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well is deemed a low pressure well. The memo provides background on low pressure wells, the technical development of the low pressure well equation (LPWE) and related correlations, comparison of LPWE predictions with those from an established well flow model, and an example calculation using the LPWE. A brief summary then follows the main body of this memo.

### **1. Background on Low Pressure Well Equation**

REC is a practice in which the natural gas produced during a well completion is captured and routed through the flow line, following hydraulic fracturing. To successfully perform an REC, the pressure of the gas needs to be sufficiently high to push the gas into the flow line. If a well does not have adequate pressure to push the gas into the flow line then the well is deemed a low pressure well.

In the March 2015 New Source Performance Standards (NSPS) proposal, EPA proposed to use the definition for low pressure gas well provided in the 2012 final NSPS rule for all wells (i.e. oil and/or gas). According to this definition, the pressure of the flowback fluid, immediately before it enters the flow line, is calculated by the following equation:

$$P_L \text{ (psia)} = 0.445 \cdot P_R - 0.038 \cdot L + 67.578 \quad (1)$$

Where  $P_L$  (psia) is predicted flow line pressure (sales line pressure is sometimes used interchangeably with flow line pressure),  $P_R$  (psia) is reservoir pressure (synonymous with formation pressure), and  $L$  (ft) is true vertical depth of the well.

If the  $P_L$  calculated using the above equation is less than the available actual flow line pressure, the well would be considered to be a low pressure well. Such a well cannot implement an REC during completion flowback.

The above equation is not appropriate for application to oil wells. This effort was undertaken to develop an equation for predicting pressure of the flowback fluid just before the fluid enters the flow line and essentially modifies equation (1) to account for additional pressure drop due to flows of oil and water.

While detailed models are available for calculating multiphase flow in oil and gas wells, these models typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. The LPWE described in this memorandum uses only those inputs for which estimates are understood to be available before well completion activity starts including:

- Wellhead production rates (gas, oil, and water);
- Wellhead oil gravity;
- Reservoir pressure and bottomhole temperature; and
- True vertical well depth.

The three flow regimes typically encountered during the flowback event include:

- a. **Fracture fluid flow.** After hydraulic fracture (frack) of a new or existing well, the well tubing is filled with large quantities of frack fluid which consists of injected liquid (i.e., water plus additives) and proppant (typically sand). This material must be evacuated to prepare the well for production.

During the initial flowback, virtually all of the flow output from the well consists of the frack material itself, rather than hydrocarbons from the formation, given that the well tubing is filled with the frack fluid. As the frack fluid reaches the surface, it is typically directed to atmospheric pressure storage, typically a tank.

- b. **Slug flow.** As the column of frack fluid flows to the surface, it is followed by hydrocarbons (gas and oil) and water from the formation and any inert gas introduced during the frack. Because of the differences in density and viscosity of the various flowback components (oil, water, gas, and frack fluid), at this point the flowing fluid typically has multi-phase slugs of gas and liquid. As the slug flow reaches the surface, it is directed to temporary storage where the liquids portion of the slug flow is contained while the gas portion of the slug flow is typically vented to the atmosphere or sent to a completion combustion device.

- c. **Steady flow.** Over time (on the order of hours to days), the slug flow transitions to a steady flow condition where the frack fluid slugs in the tubing have been largely evacuated and there is a reasonably steady flow of hydrocarbons (oil and gas) and water. For energized fracks, this steady flow of vapor may, for a time, contain a significant percentage of the inert gas introduced into the formation during the frack, and over time, (on the order of hours) the steady flow transitions to primarily hydrocarbons and water from the formation. Depending upon the pressure of the fluid (oil, gas, and water) downstream of the wellhead, the steady flow of fluid can be directed to surface equipment and then to the flow line or a completion combustion device.

The LPWE developed in this document applies to the steady flow of hydrocarbons encountered during the separation flowback stage<sup>1</sup>. Under this flow regime, gas may be separated and routed to the flow line.

## 2. Development of the Low Pressure Well Equation

Prior to developing the LPWE, research was performed to identify flow correlation models that adequately estimate the pressure drop across the well depth. In literature, a multitude of flow correlation models exist, ranging from simple pressure gradient models to complex mechanistic models. No flow correlation model is perfect and there is no model that can be applied to every situation. The hydrostatic pressure drop is typically the dominant component of pressure drop in wells. This component varies significantly with the gas-to-oil ratio, with higher volumes of oil significantly increasing the pressure drop due to oil having a higher density than gas. The frictional losses in wells constitute a small fraction of the total pressure drop across the entire well. Therefore, even for wells with horizontal section(s), it is the vertical section that determines the overall pressure drop characteristics. Hence for characterizing pressure drop in a well, it was important to focus on models that perform adequately for vertical wells. In general, the Hagedorn and Brown model<sup>2</sup> performs well for vertical wells, and is typically a good choice for such wells<sup>3</sup>.

All flow correlation models, including Hagedorn and Brown, typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. Therefore use of such models for determining REC requirements

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<sup>1</sup> Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

<sup>2</sup> Hagedorn, A.R. and Brown, K.E., "Experimental study of pressure gradients occurring during continuous two-phase flow in small diameter vertical conduits," JPT, April 1965, 475.  
<https://www.onepetro.org/journal-paper/SPE-940-PA>

<sup>3</sup> Rao, B., "Multiphase Flow Models Range of Applicability", May, 1998,  
<http://ctes.nov.com/documentation/technotes/Tech%20Note%20Multiphase%20Flow%20Models.pdf>.



could pose practical limitations. Consequently, a need was identified to develop a simpler model that could be used to determine whether an REC can be performed. The LPWE developed in this work uses only those inputs for which estimates are understood to be available before well completion activity starts.

The development of the LPWE starts from an energy balance that takes into account the two main components of pressure drop for oil and gas wells – hydrostatic and frictional. As such, the LPWE developed in this work modifies equation (1) to account for these components of pressure drop resulting from flow of oil and water in a well.

Under steady flow conditions during flow back, the flow of oil, gas, water, and proppant in well tubing can be visualized as a column of fluid<sup>4</sup> experiencing<sup>5</sup>:

- The hydrostatic pressure drop due to the weight of the fluid column in the well tubing;
- Frictional pressure drop due to friction at the tubing walls opposing the flow to the surface;
- The pressure of the hydrocarbons and water at bottom hole conditions; and
- The pressure of the hydrocarbons and water at the well head.

Consequently<sup>6</sup>,

$$P_{WH} = P_{BH} - (\Delta P_g)_h - (\Delta P_o)_h - (\Delta P_w)_h - \Delta P_f \quad (2)$$

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<sup>4</sup> Pressure drop from horizontal sections of a well is assumed to be negligible compared to the vertical sections of the same well due to the hydrostatic pressure drop being the dominant component of total pressure drop compared to the frictional component in the lateral sections.

<sup>5</sup> An additional force due to fluid acceleration is also present. Since this force contributes a negligible amount to total pressure drop across the well tubing, the impact of this force is ignored.

<sup>6</sup> Hydrostatic pressure drop due to small amounts of proppant during separation flowback is implicit in the hydrostatic drop due to water.

Where  $P_{WH}$  is well-head pressure,  $P_{BH}$  is bottomhole pressure,  $(\Delta P_g)_h$  is total hydrostatic pressure drop due to the gas phase,  $(\Delta P_o)_h$  is total hydrostatic pressure drop due to the oil phase,  $(\Delta P_w)_h$  is total hydrostatic pressure drop due to the water phase, and  $\Delta P_f$  is total frictional pressure drop.

The pressure drop due to friction typically contributes a small amount to the overall total pressure drop, and it can be expressed as a percentage,  $x(\%)$ , of the total pressure drop:

$$\Delta P_f = x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h + \Delta P_f]$$

Simplifying and solving for pressure drop due to frictional losses:

$$\Delta P_f = \frac{x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h]}{[100 - x(\%)]} \quad (3)$$

Substituting equation (3) into equation (2) yields:

$$P_{WH} = P_{BH} - (\Delta P_g)_h - (\Delta P_o)_h - (\Delta P_w)_h - \frac{x(\%) \cdot [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h]}{[100 - x(\%)]}$$

Simplifying further yields:

$$P_{WH} = P_{BH} - \left[ \frac{100}{100 - x(\%)} \right] [(\Delta P_g)_h + (\Delta P_o)_h + (\Delta P_w)_h] \quad (4)$$

Now the pressure drops due to flow of gas, oil, and water can be expressed in terms of respective pressure gradients across the well. Then equation (4) can be written as,

$$P_{WH} (psia) = P_{BH} (psia) - \left[ \frac{100}{100 - x(\%)} \right] \left[ \left( \frac{\Delta P_g}{L} \right)_h + \left( \frac{\Delta P_o}{L} \right)_h + \left( \frac{\Delta P_w}{L} \right)_h \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (5)$$

Where  $L$  is the true vertical depth of the well, expressed in feet.

In the previous evaluation conducted for the 2012 NSPS, the flow line and bottom hole pressures for a gas well were expressed as:

$$P_L (psia) = \frac{P_{WH}}{1.01} (psia) \quad (6)$$

and

$$P_{BH} (psia) = \frac{P_R}{2} (psia) \quad (7)$$

These relationships are assumed to be generally applicable to flow in petroleum wells. Then, using these equations in equation (5) yields:

$$P_L (psia) = 0.495 \cdot P_R (psia) - 0.99 \left[ \frac{100}{100-x(\%)} \right] \left[ \left( \frac{\Delta P_g}{L} \right)_h + \left( \frac{\Delta P_o}{L} \right)_h + \left( \frac{\Delta P_w}{L} \right)_h \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (8)$$

Rewriting (8) in terms of densities (pounds/cubic foot) and the related volume fractions,

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{0.99}{144^7} \cdot \left[ \frac{100}{100-x(\%)} \right] \left[ \frac{q_g}{q_g+q_o+q_w} \rho_g + \frac{q_o}{q_g+q_o+q_w} \rho_o + \frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (9)$$

Where  $q_g$ ,  $q_o$ , and  $q_w$  are the volumetric flowrates of gas, oil, and water in the well, respectively, expressed in cubic feet per second, and  $\rho_g$ ,  $\rho_o$ ,  $\rho_w$ , are the densities for the gas, oil, and water phases in the well, respectively, expressed in pounds per cubic feet.

## **2.1 Determination of hydrostatic and frictional pressure gradient due to gas flow**

Under conditions of gas flow only, equation (9) becomes

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{0.99}{144} \cdot \left[ \frac{100}{100-x(\%)} \right] \rho_g \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (10)$$

Comparing equations (1) and (10), we get,

$$\begin{aligned} & 0.445 \cdot P_R (psia) - 0.038 \cdot L(ft) + 67.578 \\ & = 0.495 \cdot P_R (psia) - \frac{0.99}{144} \cdot \left[ \frac{100}{100-x(\%)} \right] \rho_g \left( \frac{psi}{ft} \right) \cdot L(ft) \end{aligned}$$

Simplifying,

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<sup>7</sup> 144 inches squared per foot squared.

$$\frac{0.99}{144} \cdot \left[ \frac{100}{100-x(\%)} \right] \rho_g \cdot L = 0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578 (psi) \quad (11)$$

Substituting equation (11) into equation (9),

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{q_g}{q_g+q_o+q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - \frac{0.99}{144} \cdot \left[ \frac{100}{100-x(\%)} \right] \left[ \frac{q_o}{q_g+q_o+q_w} \rho_o + \frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (12)$$

## **2.2 Determination of hydrostatic pressure gradient due to water flow**

Generally a well can produce significant amounts of water while producing oil and gas. Therefore, it was important to take the water pressure gradient (psi/ft) into consideration when developing the LPWE. In the development of the LPWE the fresh water gradient of 0.433 psi/foot is used for calculating the hydrostatic pressure drop due to water<sup>8</sup>.

Then,

$$\frac{1}{144} \left[ \frac{q_w}{q_g+q_o+q_w} \rho_w \right] \left( \frac{psi}{ft} \right) = \left[ \frac{q_w}{q_g+q_o+q_w} 0.433 \right] \left( \frac{psi}{ft} \right) \quad (13)$$

Substituting (13) in (12) yields:

$$P_L (psia) = 0.495 \cdot P_R (psia) - \frac{q_g}{q_g+q_o+q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - 0.99 \cdot \left[ \frac{100}{100-x(\%)} \right] \left[ \frac{q_o}{q_g+q_o+q_w} \cdot \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433 \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (14)$$

## **2.3 Determination of Estimated Frictional Pressure Drop (%)**

As mentioned above, the Hagedorn and Brown flow model performs well for vertical wells and predicts both hydrostatic and frictional components of pressure drop based on the input conditions provided to

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<sup>8</sup> American Association of Petroleum Geologists: [http://wiki.aapg.org/Hydrostatic\\_pressure-depth\\_plot\\_construction](http://wiki.aapg.org/Hydrostatic_pressure-depth_plot_construction).

the model<sup>9</sup>. This model, henceforth referred to as the Hagedorn and Brown model, was coded in Excel by EPA and provided to ICFI. ICF checked the model and used it for validating the results of the LPWE. To evaluate the relative contribution of pressure drop due to frictional losses, an experimental matrix of model runs was created using known ranges of data from the DI Desktop™ commercial well database. These ranges are understood to cover the spectrum of oil and gas well characteristics relevant to the U.S.<sup>10</sup>. The experimental matrix is summarized in Table 1 below.

**Table 1:** Experimental Matrix of Input Variables for All Model Runs

Input Variable	Units	Values Used for All Model Runs
Oil Production Rate	Standard barrel per day	100, 200, 400, 800, 1000, 2000
Gas Production Rate	Million standard cubic feet per day	0.1, 0.3, 0.5, 1, 2, 3, 5, 10
Pressure Gradient <sup>11</sup>	psi per foot of well depth	0.35, 0.433, 0.5, 0.6, 0.75
Well Depth	Feet	500, 1000, 2500, 5000, 7000, 9000, 13000, 17000, 20000
Oil Wellhead Gravity	API	20, 30, 40, 50

Hagedorn and Brown model runs were completed and the pressure drop due to frictional losses was calculated as a percent of total pressure drop (hydrostatic and frictional). After evaluating over 7,560

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<sup>9</sup> The Hagedorn and Brown model used in this work calculates pressure drop gradient in psi/ft and multiplies the gradient by the well depth.

<sup>10</sup> For purposes of this work, wells with Gas to Oil Ratios of 300 or less were excluded from the model runs. Additionally, few model runs with negative predicted values from either Hagedorn and Brown or the LPWE were considered infeasible and removed from the results.

<sup>11</sup> Increments of pressure gradient were multiplied against values of well depth to produce values of bottomhole pressure for each model run.

dynamic model runs<sup>12</sup>, it was found that pressure drop due to frictional losses was close to 0.64% on average with a median value of 0.24%. As a conservative estimate, a value of 1% (i.e., x% = 1%) was assumed in this work to adequately characterize frictional pressure drop for operations typically encountered in U.S. oil production.

#### **2.4 The Final Low Pressure Well equation**

Assuming an average frictional component to total pressure drop ratio of 1% (i.e., x% = 1%) and substituting the value into (14), the final form of the LPWE becomes:

$$P_L (psia) = 0.495 * P_R (psia) - \frac{q_g}{q_g + q_o + q_w} [0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] - \left[ \frac{q_o}{q_g + q_o + q_w} \cdot \frac{\rho_o}{144} + \frac{q_w}{q_g + q_o + q_w} 0.433 \right] \left( \frac{psi}{ft} \right) \cdot L(ft) \quad (15)$$

The procedures for calculating oil, gas, and water flow rates and oil density to be used with the LPWE are described in Section 2.5.

Note under conditions of gas flow only (i.e.,  $q_o = q_w = 0$ ), equation (15) reduces to equation (1), the equation for gas wells. Also note that equation (15) for line pressure is derived using a vertical well. It is known that inclined wells exist in the field, which will experience a somewhat higher frictional drop due to longer flow length. Nonetheless, it is expected that equation (15) would be able to account for minor increases in pressure drop due to increased frictional drop at inclined wells because frictional pressure drop component contributes a small amount to the total pressure drop (about 1% on average) and conservative assumptions were used in deriving equation (15) – notably bottom hole pressure = ½ of formation pressure.

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<sup>12</sup> In this work, two models were used: (1) a “dynamic model” including above-the-bubble point calculations, and (2) a “simplified dynamic model” (e.g. without above-the-bubble point calculations and with a constant value for dissolved gas gravity.)\_ See Section 4 for more details.

In summary, equation (15) constitutes the LPWE developed in this work. This equation predicts the fluid pressure immediately upstream of the flow line. If this predicted pressure is higher than the available flow line pressure, the well can do an REC.

## ***2.5 Determination of Oil Density, Oil Flow Rate, and Gas Flow Rate for Use in the LPWE<sup>13</sup>***

### **2.5.1 Determination of Oil Density and Flow Rate**

Oil density used in calculating the hydrostatic pressure drop for oil is defined as an arithmetic average of the oil density at bottomhole and the oil density at the wellhead. This accounts for the fact that the density of oil increases as the hydrocarbons move up the well and dissolved gases come out of the oil. The oil flow rate used in the LPWE corresponds to the flow rate at bottomhole conditions. In essence, starting with the bottomhole flow rate, the pressure drop across the well is calculated using this flowrate and the average oil density, and then the pressure at the wellhead is determined. This “marching” calculation procedure is also used in more complex multiphase flow models.

The oil density and volumetric flow rate at bottomhole conditions are calculated using the known values of oil API gravity and oil production rate (STBO/day) at a well site and the widely used correlations provided in Vasquez and Beggs (1980).<sup>14</sup> This calculation procedure is described below<sup>15</sup>.

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<sup>13</sup> Equations marked by asterisks (\*) are not original work developed by ICF and the relevant citations are provided. ICF received an approval through EPA from the Society of Petroleum Engineers on March 14th, 2016 for reproduction and use of equations and correlations from publications in their journals.

<sup>14</sup> Vasquez, M. and Beggs, H.D., “Correlations for fluid physical property prediction,” JPT, June 1980, 968. This paper provides correlations for oil properties including dissolved gas-oil ratio and oil formation volume factor based on approximately 6000 data points - measured over large ranges of pressure, temperature, oil gravity and gas gravity.

<https://www.onepetro.org/journal-paper/SPE-6719-PA>

<sup>15</sup> The calculation procedure uses correlations for flow conditions at or below bubble point. Runs of the Hagedorn and Brown model (see Table 1), with above-bubble-point correlations revealed that above-bubble-point conditions were met in less than 10% of all dynamic model runs (see Section 4) and above-bubble-point corrections amounted to oil density corrections on the order of 4% or less. Thus, the overall impact to predicted line pressure is considered to be relatively negligible and for simplicity above-bubble-point calculations are not included in the calculation procedure.

Step 1: Determine the value of the bottom hole pressure,  $P_{BH}$ , based on available information at the well site, or by calculating it using the reservoir pressure,  $P_R$  (psia), in the following equation:

$$P_{BH} \text{ (psia)} = \frac{1}{2} P_R$$

Step 2: Determine the value of the bottom hole temperature,  $T_{BH}$  (F), based on available information at the well site, or by calculating it using the true vertical depth of the well,  $L$ (ft), in the following equation<sup>16</sup>:

$$T_{BH} \text{ (F)} = 0.014 \times L + 79.081$$

Step 3: Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig,  $\gamma_{gs}$ , using the following equation from Vasquez and Beggs (1980)<sup>14</sup> with: separator at standard conditions (pressure,  $p = 14.7$  (psia), temperature,  $T = 60$  (F)); the API oil gravity at the well site,  $\gamma_o$ ; and the oil specific gravity at the separator under standard conditions,  $\gamma_{gp} = 0.75$ :<sup>17</sup>

$$\gamma_{gs} = \gamma_{gp} \cdot \left( 1.0 + 5.912 \times 10^{-5} \cdot \gamma_o \cdot T \cdot \log \left( \frac{p}{114.7} \right) \right)^*$$

Step 4: Calculate the value of the applicable dissolved GOR,  $R_s$  (scf/STBO), using the following equation from Vasquez and Beggs (1980)<sup>14</sup> with: the bottom hole pressure,  $P_{BH}$  (psia), determined in Step 1 above; the bottom hole temperature,  $T_{BH}$  (F), determined in Step 2 above;

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<sup>16</sup> Temperature gradient data from the United States Geological Service were regressed across the sedimentary basins in the US and modeled as a function of well depth. Data is derived from USGS Open-File Report 2010-1303 titled "Comprehensive Database of Wellbore Temperatures and Drilling Mud Weight Pressures by Depth for Judge Digby Field".

<https://pubs.er.usgs.gov/publication/ofr20101303>.

<sup>17</sup> The value of 0.75 is based on expert opinion considering the average natural gas concentration data referenced in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking," July, 2011, available in the NSPS OOOO rule making docket:

<https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084>.



the gas gravity at separator pressure of 100 psig,  $\gamma_{gs}$ , calculated in Step 3 above; the oil API gravity,  $\gamma_o$ , at the well site; and the constants, C1, C2, and C3, found in Table 2:

$$R_s \left( \frac{\text{scf}}{\text{STBO}} \right) = C1 \cdot \gamma_{gs} \cdot P_{BH}^{C2} \cdot \exp \left[ C3 \left( \frac{\gamma_o}{T_{BH} + 460} \right) \right]^*$$

**Table 2.** Coefficients for the Vasquez and Beggs Correlation for  $R_s$ .

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

Step 5: Calculate the value of the oil formation volume factor,  $B_o$  (bbl/STBO), using the following equation from Vasquez and Beggs (1980)<sup>14</sup> with: the bottom hole temperature,  $T_{BH}$  (F), determined in Step 2 above; the gas gravity at separator pressure of 100 psig,  $\gamma_{gs}$ , calculated in Step 3 above; the dissolved GOR,  $R_s$  (scf/STBO), calculated in Step 4 above; the oil API gravity,  $\gamma_o$ , at the well site; and the constants, C1, C2, and C3, found in Table 3:

$$B_o \left( \frac{\text{bbl}}{\text{STBO}} \right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60) \left( \frac{\gamma_o}{\gamma_{gs}} \right) \cdot (C2 + C3 \cdot R_s)^*$$

**Table 3.** Coefficients for the Vasquez and Beggs Correlation for  $B_o$

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	$4.677 \times 10^{-4}$	$4.670 \times 10^{-4}$
C2	$1.751 \times 10^{-5}$	$1.100 \times 10^{-5}$

C3	-1.811x10 <sup>-8</sup>	1.337x10 <sup>-9</sup>
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Step 6: Calculate the density of oil at the wellhead,  $\rho_{WH} \left( \frac{lbm}{cu\ ft} \right)$ , using the following equation with the value of the oil API gravity,  $\gamma_o$ , at the well site:

$$\rho_{WH} \left( \frac{lbm}{cu\ ft} \right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

Step 7: Calculate the density of oil at bottom hole conditions,  $\rho_{BH} \left( \frac{lbm}{cu\ ft} \right)$ , using the following equation with: the dissolved GOR,  $R_s$  (scf/STBO), calculated in Step 4 above; the oil formation volume factor,  $B_o$  (bbl/STBO), calculated in Step 5 above; the oil density at the wellhead,

$\rho_{WH} \left( \frac{lbm}{cu\ ft} \right)$ , calculated in Step 6 above; and the dissolved gas gravity,  $\gamma_{gd} = 0.77$ <sup>18</sup>:

$$\rho_{BH} \left( \frac{lbm}{cu\ ft} \right) = \frac{\rho_{WH} + 0.0136 \times R_s \times \gamma_{gd}}{B_o}$$

Step 8: Calculate the density of oil in the well,  $\rho_o \left( \frac{lbm}{cu\ ft} \right)$ , using the following equation with the density of oil at the wellhead,  $\rho_{WH} \left( \frac{lbm}{cu\ ft} \right)$ , calculated in Step 6 above; and the density of oil at bottom hole conditions,  $\rho_{BH} \left( \frac{lbm}{cu\ ft} \right)$ , calculated in Step 7 above:

$$\rho_o \left( \frac{lbm}{cu\ ft} \right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

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<sup>18</sup> Figure B-10 (Katz diagram) from Brill, J.P. and Mukherjee, H., "Multiphase Flow in Wells", Monograph Volume 17, SPE, 1999 was used to calculate the values of this variable in the model runs described in Section 2.4. It was found that dissolved gas gravity,  $\gamma_{gd}$ , did not have a significant impact on predicted flow line pressure. Therefore a value of 0.77 is recommended to be used for  $\gamma_{gd}$ . This value is the average of the values used in the dynamic model runs (see Section 4).

Step 9: Calculate the oil flow rate,  $q_o$  (cu ft/sec), using the following equation with: the oil formation volume factor,  $Bo$  (bbl/STBO), calculated in Step 4 above; and the estimated oil production rate at the well head,  $Q_o$  (STBO/day):

$$q_o \left( \frac{\text{cu ft}}{\text{sec}} \right) = Q_o \left( \frac{\text{STBO}}{\text{day}} \right) \times Bo \left( \frac{\text{bbl}}{\text{STBO}} \right) \times 5.614 \left( \frac{\text{cu ft}}{\text{bbl}} \right) \times \frac{1}{24 \times 60 \times 60} \left( \frac{\text{day}}{\text{sec}} \right)$$

### 2.5.2 Determination of Gas Flow Rate

As oil-gas-water mixture flows upwards in a well to a lower pressure location, gas volume changes and some of the dissolved gas evolves out of solution in oil. This results in gas volumetric flow (and therefore pressure gradient) changing with well depth.

The gas volumetric flow at bottomhole conditions is calculated in a sequential fashion, first evaluating terms to estimate gas compressibility factor,  $z$ . The Standing and Katz correlation and  $z$ -factor chart<sup>19</sup> was used to estimate critical pressure and temperature at bottomhole conditions. Then, adjustments were made to the critical pressure and temperature according to the Carr/Kobayashi<sup>20</sup> method to account for potential impurities in the natural gas. Finally, the Brill and Beggs correlation for compressibility<sup>21</sup> was utilized to estimate the  $z$ -factor. This calculation procedure is described below in detail:

Step 10: Calculate the critical pressure,  $P_c$  (psia), and critical temperature,  $T_c$  (R), using the aforementioned Standing and Katz correlation and Carr/Kobayashi adjustment with specific

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<sup>19</sup> Standing, M.B. and Katz, D.L., "Density of Natural Gases," Transactions of the AIME, SPE, December, 1942, 146.

<https://www.onepetro.org/journal-paper/SPE-942140-G>.

<sup>20</sup> To derive the equations, first adjustment factors for N<sub>2</sub>, CO<sub>2</sub>, and H<sub>2</sub>S were obtained from Figure 8 in Carr, N. L., Kobayashi, R., and Burrows, D.B., "Viscosity of Hydrocarbon Gases Under Pressure," JPT, SPE, October, 1954, 6. Then these factors were applied to Standing and Katz correlations for  $P_c$  and  $T_c$ .

<https://www.onepetro.org/journal-paper/SPE-297-G>.

<sup>21</sup> Guo, B., Ghalambor, A., "Natural Gas Engineering Handbook," Gulf Publishing Company, 2005, ISBN 0976511339, Chapter 2 equations 2.28 to 2.33.

gravity of gas at standard conditions ( $p=14.7$  psia and  $T = 60$  F),  $SG = 0.75$ ; and where the mole fractions in the gas of nitrogen, carbon dioxide and hydrogen sulfide are:  $X_{N_2} = 0.168225$ ,  $X_{CO_2} = 0.013163$ , and  $X_{H_2S} = 0.013680^{22}$ . The equations below for critical temperature and critical pressure represent the combined Standing correlation and Carr/Kobayashi adjustments into one form.

$$P_c(\text{psia}) = 678 - 50 \cdot (SG - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}^*$$

$$T_c(R) = 326 + 315.7 \cdot (SG - 0.5) - 240 \cdot X_{N_2} - 83.3 \cdot X_{CO_2} + 133.3 \cdot X_{H_2S}^*$$

Step 11: Calculate reduced pressure,  $P_r$ , and reduced temperature,  $T_r$ , using the following equations with: the bottom hole pressure,  $P_{BH}$  (psia), as determined in Step 1 above; the bottom hole temperature,  $T_{BH}$  (F), as determined in Step 2 above in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{(T_{BH} + 460)}{T_c}$$

Step 12: Calculate the gas compressibility factor,  $Z$ , using the following Brill and Beggs correlation with the reduced pressure,  $P_r$ , calculated in Step 10 above:

$$Z = A + \frac{(1-A)}{e^B} + C \cdot p_r^{D*}$$

The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure,  $P_r$ , and reduced temperature,  $T_r$ , calculated in Step 10 above:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 \cdot T_r - 0.10$$

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<sup>22</sup> The mole fractions are the averages for compositions in oil and gas wells and are based on information in Table 8 in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking," July, 2011, available in the NSPS OOOO rule making docket <https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084>.

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left( \frac{0.066}{(T_r - 0.86)} - 0.037 \right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

Step 13: Calculate the gas formation volume factor,  $B_g \left( \frac{cuft}{scf} \right)$ , using the real gas law below with the bottom hole pressure,  $P_{BH}$  (psia), as determined in Step 1 above; and the bottom hole temperature,  $T_{BH}$  (F), as determined in Step 2 above:

$$B_g \left( \frac{cuft}{scf} \right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)^*}{P_{BH}}$$

Step 14: Calculate the gas flow rate,  $q_g \left( \frac{cuft}{sec} \right)$ , using the following equation with: the value of gas formation volume factor,  $B_g \left( \frac{cuft}{scf} \right)$ , calculated in Step 12 above; the estimated gas production rate,  $Q_g$  (scf/day); the estimated oil production rate,  $Q_o$  (STBO/day); and the dissolved GOR,  $R_s$  (scf/STBO), as calculated in Step 4 above:

$$q_g \left( \frac{cf}{sec} \right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24 \times 60 \times 60}$$

### 2.5.3 Determination of Water Flow Rate

Step 15: Generally, water is relatively incompressible and gas solubility in water is negligible.

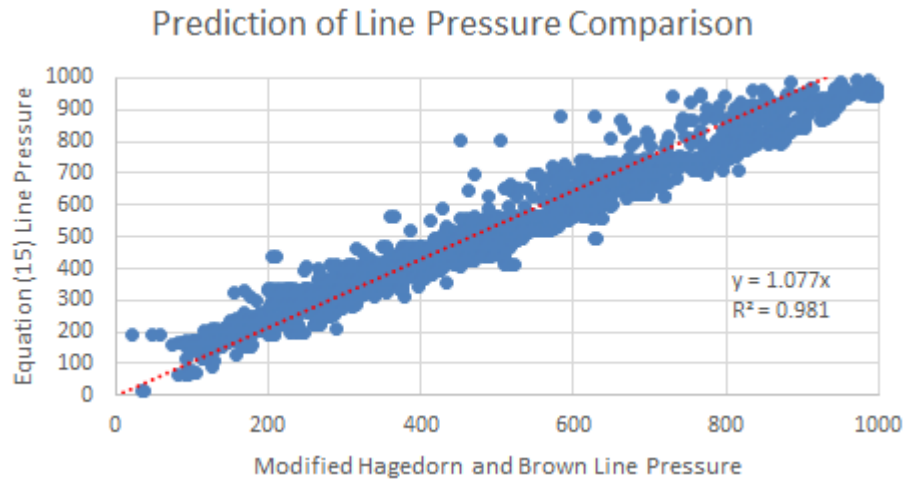
Therefore,  $q_w \left( \frac{cf}{sec} \right)$ , the flow rate of water in the well, is calculated using the following equation with the water production rate  $Q_w$  (bbl/day) at the well site:

$$q_w \left( \frac{cf}{sec} \right) = Q_w \left( \frac{STB}{day} \right) \times 5.614 \left( \frac{cf}{bbl} \right) \times \frac{1}{24 \times 60 \times 60} \left( \frac{day}{sec} \right)$$

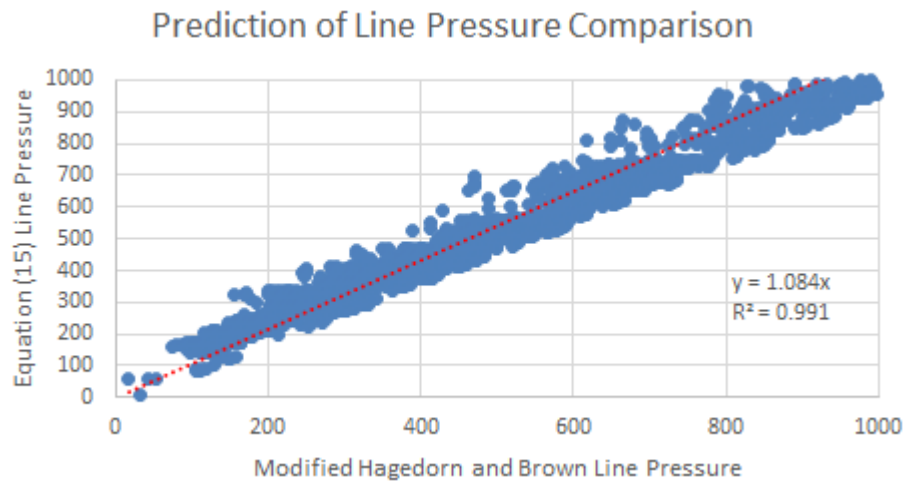
#### **4. Comparison of the Low Pressure Oil Well Equation Results with those from the Hagedorn and Brown Model**

As discussed previously, the Hagedorn and Brown flow correlation method generally predicts pressure drop for vertical wells better than the other models. The Hagedorn and Brown model was used for validating the results of the LPWE, equation (15). For validation purposes, model runs were completed using the experimental matrix shown in Table 1 above.

Over 7,560 model runs were performed using the coded Hagedorn and Brown model and simultaneously corresponding calculations were made with the LPWE (equation (15)). In this version of the Hagedorn and Brown model, called the dynamic model, certain calculations (i.e., bubble point pressure corrections and dissolved gas gravity) were completed using established correlations. While completing experimental matrix runs with the dynamic model, it was observed that correction for above-the-bubble point pressure and changes in dissolved gas gravity did not have a significant impact on model results (see footnotes 15 and 18). Consequently, a simplified dynamic model was created without above-the-bubble point calculations and with a fixed value for dissolved gas gravity (footnote 18). Subsequently, the same 7,560 model runs as above were completed with the simplified dynamic model. Results for line pressure from Hagedorn and Brown model runs are compared with corresponding results from the LPWE (equation (15)) in Figure 1 for the dynamic model case and in Figure 2 for the simplified dynamic model case.



**Figure 1:** Comparison of Line Pressure Prediction for the Dynamic Model



**Figure 2:** Comparison of Line Pressure Prediction for the Simplified Dynamic Model

Since the difference between Figure 1 and Figure 2 is negligible, the LPWE related calculation procedure described in Section 2.5 is appropriate. Finally, in addition to the comparison plots shown above, a multiple linear regression for line pressure predictions below 1000 psia was performed for data in Figure 2 and a standard error of 41 psia was observed<sup>23</sup>. These results indicate that the LPWE estimates pressure drops comparable to the Hagedorn and Brown model.

<sup>23</sup> The standard error in this context represents an over-prediction of line pressure by 41 psia on average for equation (15) when compared to the Hagedorn and Brown method.

## 5. Example Calculation

For the example calculation with the LPWE, input conditions (illustrative example) are defined as follows:

- Well depth,  $L = 7,900$  feet
- Reservoir pressure,  $P_R = 2,700$  psia
- Bottomhole temperature,  $T_{BH} = 180$  °F
- Oil production rate,  $Q_o = 465$  STBOD
- Water production rate,  $Q_w = 45$  STBOD
- Gas production rate,  $Q_g = 570,000$  scf/day
- API gravity,  $\gamma_o = 25$
- Available flow line pressure= 150 psia

### Calculation of Oil Density and Flow Rate

**Step 1.** Calculate the bottomhole pressure using (Step 1, Section 2.5):

$$P_{BH}(psia) = \frac{1}{2}(2,700 psia) = 1,350psia$$

**Step 2.** Determine the bottomhole temperature (Step 2, Section 2.5):

From the information provided,

$$T_{BH}(F) = 180 F$$

**Step 3.** Calculate gas gravity at from a separator pressure of 100 psig,  $\gamma_{gs}$  (Step 3, Section 2.5):

$$\gamma_{gs} = (0.75) \cdot \left( 1.0 + 5.912 \times 10^{-5} \cdot 25 \cdot 60^\circ F \cdot \log \left( \frac{14.7 psia}{114.7} \right) \right) = 0.691$$

**Step 4.** Calculate dissolved GOR,  $R_s$  (Step 4, Section 2.5):



$$R_s \left( \frac{scf}{STBO} \right) = (0.0362) \cdot (0.691) \cdot (1,350 \text{ psia})^{1.0937} \cdot \exp \left[ 25.7240 \cdot \left( \frac{25}{180^\circ F + 460} \right) \right]$$

$$= 181.14 \left( \frac{scf}{STBO} \right)$$

**Step 5.** Calculate the volume formation factor for oil,  $B_o$  (Step 5, Section 2.5):

$$B_o \left( \frac{bbl}{STBO} \right) = 1.0 + (4.677 \cdot 10^{-4} \cdot 181.14 \left( \frac{scf}{STBO} \right) + (180^\circ F - 60) \left( \frac{25}{0.691} \right) \cdot \left( 1.751 \cdot 10^{-5} - 1.811 \cdot 10^{-8} \cdot 181.14 \left( \frac{scf}{STBO} \right) \right) = 1.147 \left( \frac{bbl}{STBO} \right)$$

**Step 6.** Calculate the density of oil at the wellhead (Step 6, Section 2.5):

$$\rho_{WH} = \frac{141.5}{25 + 131.5} \cdot 62.4 = 56.42 \left( \frac{lb_m}{cuft} \right)$$

**Step 7.** Calculate the density of oil at bottomhole (Step 7, Section 2.5):

$$\rho_{BH} \left( \frac{lb_m}{cuft} \right) = \frac{56.42 + 0.0136 \cdot 181.14 \left( \frac{scf}{STBO} \right) \cdot 0.77}{1.147 \left( \frac{bbl}{STBO} \right)} = 50.86 \left( \frac{lb_m}{cuft} \right)$$

**Step 8.** Calculate the average oil density,  $\rho_o$  (Step 8, Section 2.5):

$$\rho_o \left( \frac{lb_m}{cuft} \right) = \frac{1}{2} \left[ 56.42 \left( \frac{lb_m}{cuft} \right) + 50.86 \left( \frac{lb_m}{cuft} \right) \right] = 53.64 \left( \frac{lb_m}{cuft} \right)$$

**Step 9:** Calculate the oil flow rate at bottomhole conditions (Step 9, Section 2.5):

$$q_o \left( \frac{cuft}{sec} \right) = 465 \frac{STBO}{Day} \cdot 1.147 \left( \frac{bbl}{STBO} \right) \cdot \left( \frac{5.614}{24 \cdot 60 \cdot 60} \right) = 0.0346 \left( \frac{cuft}{sec} \right)$$

#### Calculation of Gas Flow Rate

**Step 10.** Calculate critical pressure and temperature (Step 10, Section 2.5):

$$P_c = 678 - 50 \cdot (0.75 - 0.5) - 206.7 \cdot 0.168225 + 440 \cdot 0.013163 + 606.7 \cdot 0.01368$$

$$= 644.819 \text{ psia}$$

$$T_c = 326 + 315.7 \cdot (0.75 - 0.5) - 240 \cdot 0.168225 - 83.3 \cdot 0.013163 + 133.3 \cdot 0.01368$$

$$= 365.278 \text{ }^\circ R$$

**Step 11.** Calculate reduced pressure and temperature (Step 11, Section 2.5):

$$P_r = \frac{1,350 \text{ psia}}{644.819 \text{ psia}} = 2.094$$

$$T_r = \frac{640 \text{ }^\circ R}{365.278 \text{ }^\circ R} = 1.752$$

**Step 12.** Calculate gas compressibility factor,  $z$  (Step 12, Section 2.5):

$$A = 1.39 \cdot (1.752 - 0.92)^{0.5} - 0.36 \cdot 1.752 - 0.101 = 0.536$$

$$B = (0.62 - 0.23 \cdot 1.752) \cdot 2.094 + \left( \frac{0.066}{(1.752 - 0.86)} - 0.037 \right) \cdot (2.094)^2 + \frac{0.32}{10^{9 \cdot (1.752 - 1)}}$$

$$\cdot (2.094)^6 = 0.616$$

$$C = (0.132 - 0.32 \cdot \log(1.752)) = 0.054$$

$$D = 10^{0.3106 - 0.49 \cdot (1.752) + 0.1824 \cdot (1.752)^2} = 1.028$$

$$z = 0.537 + \frac{(1 - 0.537)}{e^{0.245}} + 0.054 \cdot (0.968)^{1.028} = 0.902$$

**Step 13.** Calculate the gas formation volume factor,  $B_g$  (Step 13, Section 2.5):

$$B_g \left( \frac{\text{cuft}}{\text{scuft}} \right) = 0.0283 \cdot \left( \frac{0.902 \cdot 640 \text{ }^\circ R}{1,350 \text{ psia}} \right) = 0.0121 \left( \frac{\text{cuft}}{\text{scuft}} \right)$$

**Step 14.** Calculate the volumetric flow rate of the gas (Step 14, Section 2.5):

$$q_g \left( \frac{\text{cuft}}{\text{sec}} \right) = \left( 570,000 \left( \frac{\text{scf}}{\text{day}} \right) - 181.14 \left( \frac{\text{scf}}{\text{STBO}} \right) \cdot 465 \text{ stbod} \right) \cdot 0.0121 \left( \frac{\text{cuft}}{\text{scuft}} \right) \cdot \left( \frac{1}{24 \cdot 60 \cdot 60} \right)$$

$$= 0.0680 \left( \frac{\text{cuft}}{\text{sec}} \right)$$

**Step 15.** Express water flow rate in cu ft/sec (Step 13, Section 2.5):

$$q_w \left( \frac{cuft}{sec} \right) = 45 \frac{STBO}{Day} \cdot \left( \frac{5.614}{24 \cdot 60 \cdot 60} \right) = 0.0029 \left( \frac{cuft}{sec} \right)$$

Finally, the line pressure can be evaluated using equation (15) to determine predicted flow line pressure.

$$P_L (psia) = 0.495 \cdot 2,700(psia)$$

$$\begin{aligned} & - \frac{0.068 \left( \frac{cuft}{s} \right)}{\left( 0.068 \left( \frac{cuft}{s} \right) + 0.0346 \left( \frac{cuft}{s} \right) + 0.0029 \left( \frac{cuft}{s} \right) \right)} \left[ 0.05 \cdot 2,700(psia) \right. \\ & \left. + 0.038 \left( \frac{psia}{ft} \right) \cdot 7,900(ft) - 67.578(psia) \right] \\ & - 1.00 \left[ \frac{0.0346 \left( \frac{cuft}{s} \right)}{\left( 0.068 \left( \frac{cuft}{s} \right) + 0.0346 \left( \frac{cuft}{s} \right) + 0.0029 \left( \frac{cuft}{s} \right) \right)} \cdot \frac{53.641 \left( \frac{lb_m}{cuft} \right)}{144 \left( \frac{psia}{\left( \frac{lb_m}{ft^2} \right)} \right)} \right. \\ & \left. + \frac{0.0029 \left( \frac{cuft}{s} \right)}{\left( 0.068 \left( \frac{cuft}{s} \right) + 0.0346 \left( \frac{cuft}{s} \right) + 0.0029 \left( \frac{cuft}{s} \right) \right)} \cdot 0.433 \left( \frac{psia}{ft} \right) \right] \\ & \cdot 7,900(ft) = 39.7(psia) \end{aligned}$$

Since  $P_L = 39.7 \text{ psia} < \text{available flow line pressure} = 150 \text{ psia}$ , the well may not be able to perform an REC. On the other hand, if the sales line pressure is below 39.7 psia, then the operator may be able to perform an REC within operational constraints.

## 6. Summary

This memo describes the development of the low pressure well equation, LPWE, appropriate for use at well sites to determine whether or not a well can implement an REC. This equation uses only those inputs for which estimates are understood to be available before well completion activity starts to calculate the flowback fluid pressure immediately upstream of the flow line. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well can be deemed a low pressure well and may not be able to perform REC. The equation was tested against an established and widely used multiphase flow model using a range of conditions representative of wells in the U.S. The results from the equation were generally consistent with those from the established Hagedorn and Brown model.

## Appendix

Additional analysis was performed to characterize oil and gas wells with respect to the low pressure well equation. The analysis informs assumptions about the proportion of hydraulically fractured well completions that would be considered low pressure using the low pressure well equation.

This document analyzes roughly 37,800 oil and gas wells across the United States and applies the low pressure well equation to each of the wells to determine a prediction of flow line pressure. Based on various filters described below, the wells were characterized in a set of tables. Finally, in addition to evaluating flow line pressure using the draft low pressure well equation, data from the Green House Gas Reporting Program (GHGRP) was utilized to determine average separator pressure and API gravity according to basin.

For all subsequent tables, wells were classified as low pressure wells if the predicted flow line pressure was less than the average separator pressure for the associated basin as reported in the GHGRP Subpart W for 2014. If the flow line pressure was greater than the average separator pressure, the well was classified as a high pressure well. Although in some cases there will be a dehydrator or other equipment downstream of the separator, which will result in a pressure drop, the separator pressure is the closest metric available to the flowline pressure, and was therefore used in this analysis.

Table 1 shows the distribution of oil and gas wells (identified using a GOR threshold of 100,000 scf/bbl) and whether the wells would be considered high pressure (HP) or low pressure (LP) using the LPWE. Table 2 performs the same analysis but excludes wells with  $GOR < 300$  scf/bbl. Table 3 provides the oil and gas well splits with additional detail on basin type. Tables 1 through 3 are generated based on 2014 annual oil and gas production values<sup>24</sup>.

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<sup>24</sup> Values obtained from the DI Desktop™ commercial well database for well completions in 2014.

We assume that hydraulically fractured oil well completions occur in shale oil basins. While variations from this assumption are very likely, we believe this is a reasonable assumption for this analysis. **Based on this assumption and according to this analysis, about 40 percent (3,717 of 9,227 completions) for shale oil wells with GOR>300 scf/bbl would be considered low pressure using the low pressure well equation.**

**Table 1:** Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl including all GORs

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	35,793	14,583	21,210
Gas Well	2,015	1,918	97

**Table 2:** Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl excluding GORs <300

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	22,093	13,701	8,392
Gas Well	2,015	1,918	97

**Table 3:** Oil and Gas Well Splits by Basin Type for GORs > 300 with Gas Well Cutoff of 100,000 scf/bbl<sup>25</sup>

Basin Type	Total Count	HP Well Count	LP Well Count
Conventional	12,505	8,770	3,735
Oil	11,288	7,616	3,672
Gas	1,217	1,154	63
Shale Oil	9,227	5,510	3,717
Tight Gas	1,953	972	981
Shale Gas	417	361	56
Coal Bed Methane	5	5	0

<sup>25</sup> The categories of shale oil, tight gas, and shale gas are based on the DI Database basin type designation. With the 100,000 scf/bbl cutoff, some of these wells could be classified as oil or gas wells but were not reclassified and the basin type designation was used to classify these wells.

MarkWest Liberty Midstream & Resources, L.L.C.  
Harmon Creek Gas Plant

Summary of Potential Emissions

Criteria Pollutant Potential Emissions

Process/Facility	Source ID	Potential Emissions (lb/hr)					
		NOx	CO	VOC	SO <sub>2</sub>	PM <sup>1</sup>	HAPs
Cryo Plant 1 Regen Heater (H-1711)	031	0.47	0.47	0.22	0.01	0.09	0.02
Cryo Plant 2 Regen Heater (H-2711)	037	0.20	0.71	0.34	0.01	0.23	0.03
<b>Cryo Plant 3 Regen Heater (H-3711)</b>	<b>038</b>	<b>0.26</b>	<b>0.87</b>	<b>0.42</b>	<b>0.01</b>	<b>0.28</b>	<b>0.04</b>
De-Ethanizer HMO Heater 1 (H-1767)	033	1.93	1.93	0.91	0.03	0.36	0.09
De-Ethanizer HMO Heater 2 (H-1768)	034	1.93	1.93	0.91	0.03	0.36	0.09
<b>De-Ethanizer 2 HMO Heater 1 (H-3767)</b>	<b>039</b>	<b>0.89</b>	<b>2.94</b>	<b>1.42</b>	<b>0.04</b>	<b>0.96</b>	<b>0.14</b>
<b>De-Ethanizer 2 HMO Heater 2 (H-3768)</b>	<b>040</b>	<b>0.89</b>	<b>2.94</b>	<b>1.42</b>	<b>0.04</b>	<b>0.96</b>	<b>0.14</b>
Stabilization HMO Heater (H-1769)	036	0.48	0.48	0.23	0.01	0.09	0.02
De-Ethanizer Regen Heater (H-1775)	035	0.26	0.26	0.13	0.00	0.05	0.01
Generac SD015	102	0.26	0.14	0.08	0.10	0.02	0.00
Generac SD150	102	1.31	0.55	0.41	0.10	0.04	0.01
Fugitives Emissions	701	--	--	--	--	--	--
Process Flare	C601	1.11	5.08	2.74	0.01	0.10	0.05
<b>HC3/De-Eth 2 Venting</b>	--	--	--	<b>0.04</b>	--	--	<b>0.00</b>
<i>Pigging*</i>	801	--	--	--	--	--	--
<i>Blowdowns*</i>	601	--	--	--	--	--	--
<i>Drain Tank Loadout*</i>	702	--	--	--	--	--	--
<i>Regen Dry Seal Vents*</i>	602	--	--	--	--	--	--
Rod Packing	601	--	--	0.27	--	--	0.00
<b>Residue Dry Seal Vents</b>	<b>602</b>	--	--	<b>0.31</b>	--	--	<b>0.00</b>
Methanol Tanks	--	--	--	0.12	--	--	0.12
Measurement Devices	--	--	--	0.41	--	--	0.01
<b>Future Site-Wide Emissions (lb/hr)</b>		<b>9.98</b>	<b>18.30</b>	<b>10.39</b>	<b>0.40</b>	<b>3.54</b>	<b>0.77</b>

Process/Facility	Source ID	Potential Emissions (tpy)					
		NOx	CO	VOC	SO <sub>2</sub>	PM <sup>1</sup>	HAPs
Cryo Plant 1 Regen Heater (H-1711)	031	2.07	2.07	0.98	0.03	0.39	0.10
Cryo Plant 2 Regen Heater (H-2711)	037	0.86	3.13	1.48	0.05	1.02	0.14
<b>Cryo Plant 3 Regen Heater (H-3711)</b>	<b>038</b>	<b>1.14</b>	<b>3.79</b>	<b>1.83</b>	<b>0.06</b>	<b>1.24</b>	<b>0.18</b>
De-Ethanizer HMO Heater 1 (H-1767)	033	8.44	8.44	4.01	0.12	1.57	0.39
De-Ethanizer HMO Heater 2 (H-1768)	034	8.44	8.44	4.01	0.12	1.57	0.39
<b>De-Ethanizer 2 HMO Heater 1 (H-3767)</b>	<b>039</b>	<b>3.88</b>	<b>12.87</b>	<b>6.21</b>	<b>0.19</b>	<b>4.21</b>	<b>0.60</b>
<b>De-Ethanizer 2 HMO Heater 2 (H-3768)</b>	<b>040</b>	<b>3.88</b>	<b>12.87</b>	<b>6.21</b>	<b>0.19</b>	<b>4.21</b>	<b>0.60</b>
Stabilization HMO Heater (H-1769)	036	2.10	2.10	1.00	0.03	0.39	0.10
De-Ethanizer Regen Heater (H-1775)	035	1.16	1.16	0.55	0.02	0.22	0.05
Generac SD015	102	0.07	0.04	0.02	0.03	0.01	0.00
Generac SD150	102	0.33	0.14	0.10	0.03	0.01	0.00
Fugitives Emissions	701	--	--	4.86	--	--	0.15
Process Flare	C601	4.88	22.24	12.01	0.04	0.46	0.21
<b>HC3/De-Eth 2 Venting</b>	--	--	--	<b>0.18</b>	--	--	<b>0.003</b>
<i>Pigging*</i>	801	--	--	--	--	--	--
<i>Blowdowns*</i>	601	--	--	--	--	--	--
<i>Drain Tank Loadout*</i>	702	--	--	--	--	--	--
<i>Regen Dry Seal Vents*</i>	602	--	--	--	--	--	--
Rod Packing	601	--	--	1.20	--	--	0.01
<b>Residue Dry Seal Vents</b>	<b>602</b>	--	--	<b>1.34</b>	--	--	<b>0.00</b>
Methanol Tanks	--	--	--	0.53	--	--	0.53
Measurement Devices	--	--	--	1.81	--	--	0.03
<b>Future Site-Wide Emissions (tpy)</b>		<b>37.24</b>	<b>77.29</b>	<b>48.33</b>	<b>0.90</b>	<b>15.27</b>	<b>3.48</b>

<sup>1</sup> PM = PM<sub>10</sub> = PM<sub>2.5</sub>

\* Emissions are controlled by the flare or VRU and thus, are accounted for in the process flare emissions or HC3/De-Eth2 venting emissions. See detailed emission table for additional information.

**Hazardous Air Pollutant Potential Emissions**

Process/Facility	Source ID	HAPs - Potential Emissions (lb/hr)								
		Acetaldehyde	Acrolein	Benzene	Ethylbenzene	Formaldehyde	Methanol	n-Hexane	Toluene	Xylenes
Cryo Plant 1 Regen Heater (H-1711)	031	--	--	2.44E-05	--	8.70E-04	--	0.02	3.95E-05	--
Cryo Plant 2 Regen Heater (H-2711)	037	--	--	3.67E-05	--	1.31E-03	--	0.03	5.95E-05	--
<b>Cryo Plant 3 Regen Heater (H-3711)</b>	<b>038</b>	--	--	<b>4.48E-05</b>	--	<b>1.60E-03</b>	--	<b>0.04</b>	<b>7.25E-05</b>	--
De-Ethanizer HMO Heater 1 (H-1767)	033	--	--	9.91E-05	--	3.54E-03	--	0.08	1.60E-04	--
De-Ethanizer HMO Heater 2 (H-1768)	034	--	--	9.91E-05	--	3.54E-03	--	0.08	1.60E-04	--
<b>De-Ethanizer 2 HMO Heater 1 (H-3767)</b>	<b>039</b>	--	--	<b>1.52E-04</b>	--	<b>5.43E-03</b>	--	<b>0.13</b>	<b>2.46E-04</b>	--
<b>De-Ethanizer 2 HMO Heater 2 (H-3768)</b>	<b>040</b>	--	--	<b>1.52E-04</b>	--	<b>5.43E-03</b>	--	<b>0.13</b>	<b>2.46E-04</b>	--
Stabilization HMO Heater (H-1769)	036	--	--	2.47E-05	--	8.82E-04	--	0.02	4.00E-05	--
De-Ethanizer Regen Heater (H-1775)	035	--	--	1.36E-05	--	4.85E-04	--	0.01	2.20E-05	--
Generac SD015	102	2.89E-04	3.48E-05	3.51E-04	--	4.44E-04	--	--	1.54E-04	1.07E-04
Generac SD150	102	1.42E-03	1.72E-04	1.73E-03	--	2.19E-03	--	--	7.59E-04	5.29E-04
Fugitives Emissions	701	--	--	--	--	--	--	--	--	--
Process Flare	C601	--	--	3.45E-03	3.45E-03	--	--	0.02	6.10E-03	1.17E-03
<b>HC3/De-Eth 2 Venting</b>	--	--	--	5.43E-05	5.43E-05	--	--	3.45E-04	9.61E-05	1.85E-05
<i>Pigging*</i>	801	--	--	--	--	--	--	--	--	--
<i>Blowdowns*</i>	601	--	--	--	--	--	--	--	--	--
<i>Drain Tank Loadout*</i>	702	--	--	--	--	--	--	--	--	--
<i>Regen Dry Seal Vents*</i>	602	--	--	--	--	--	--	--	--	--
Rod Packing	601	--	--	0.00	0.00	--	--	0.00	0.00	0.00
<b>Residue Dry Seal Vents</b>	<b>602</b>	--	--	<b>4.13E-04</b>	<b>4.13E-04</b>	--	--	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>
Methanol Tanks	--	--	--	--	--	--	1.21E-01	--	--	--
Measurement Devices	--	--	--	5.19E-04	5.19E-04	--	--	0.00	9.19E-04	1.76E-04
<b>Future Site-Wide Emissions (lb/hr)</b>		<b>0.00</b>	<b>0.00</b>	<b>0.01</b>	<b>0.00</b>	<b>0.03</b>	<b>0.12</b>	<b>0.58</b>	<b>0.01</b>	<b>0.00</b>

Process/Facility	Source ID	HAPs - Potential Emissions (tpy)								
		Acetaldehyde	Acrolein	Benzene	Ethylbenzene	Formaldehyde	Methanol	n-Hexane	Toluene	Xylenes
Cryo Plant 1 Regen Heater (H-1711)	031	--	--	1.07E-04	--	3.81E-03	--	0.09	1.73E-04	--
Cryo Plant 2 Regen Heater (H-2711)	037	--	--	1.61E-04	--	5.75E-03	--	0.14	2.60E-04	--
<b>Cryo Plant 3 Regen Heater (H-3711)</b>	<b>038</b>	--	--	<b>1.96E-04</b>	--	<b>7.00E-03</b>	--	<b>0.17</b>	<b>3.18E-04</b>	--
De-Ethanizer HMO Heater 1 (H-1767)	033	--	--	4.34E-04	--	1.55E-02	--	0.37	7.03E-04	--
De-Ethanizer HMO Heater 2 (H-1768)	034	--	--	4.34E-04	--	1.55E-02	--	0.37	7.03E-04	--
<b>De-Ethanizer 2 HMO Heater 1 (H-3767)</b>	<b>039</b>	--	--	<b>6.66E-04</b>	--	<b>2.38E-02</b>	--	<b>0.57</b>	<b>1.08E-03</b>	--
<b>De-Ethanizer 2 HMO Heater 2 (H-3768)</b>	<b>040</b>	--	--	<b>6.66E-04</b>	--	<b>2.38E-02</b>	--	<b>0.57</b>	<b>1.08E-03</b>	--
Stabilization HMO Heater (H-1769)	036	--	--	1.08E-04	--	3.86E-03	--	0.09	1.75E-04	--
De-Ethanizer Regen Heater (H-1775)	035	--	--	5.95E-05	--	2.13E-03	--	0.05	9.64E-05	--
Generac SD015	102	7.22E-05	8.70E-06	8.78E-05	--	1.11E-04	--	--	3.85E-05	2.68E-05
Generac SD150	102	3.56E-04	4.29E-05	4.33E-04	--	5.47E-04	--	--	1.90E-04	1.32E-04
Fugitives Emissions	701	--	--	--	--	--	--	--	--	--
Process Flare	C601	--	--	1.51E-02	1.51E-02	--	--	0.10	2.67E-02	5.13E-03
<b>HC3/De-Eth 2 Venting</b>	--	--	--	2.38E-04	2.38E-04	--	--	1.51E-03	4.21E-04	8.09E-05
<i>Pigging*</i>	801	--	--	--	--	--	--	--	--	--
<i>Blowdowns*</i>	601	--	--	--	--	--	--	--	--	--
<i>Drain Tank Loadout*</i>	702	--	--	--	--	--	--	--	--	--
<i>Regen Dry Seal Vents*</i>	602	--	--	--	--	--	--	--	--	--
Rod Packing	601	--	--	0.00	0.00	--	--	0.01	0.00	0.00
<b>Residue Dry Seal Vents</b>	<b>602</b>	--	--	<b>1.81E-03</b>	<b>1.81E-03</b>	--	--	<b>0.01</b>	<b>0.00</b>	<b>0.00</b>
Methanol Tanks	--	--	--	--	--	--	5.28E-01	--	--	--
Measurement Devices	--	--	--	2.27E-03	2.27E-03	--	--	0.01	4.02E-03	7.73E-04
<b>Future Site-Wide Emissions (tpy)</b>		<b>0.00</b>	<b>0.00</b>	<b>0.02</b>	<b>0.02</b>	<b>0.10</b>	<b>0.53</b>	<b>2.56</b>	<b>0.04</b>	<b>0.01</b>

\* Emissions are controlled by the flare or VRU and thus, are accounted for in the process flare emissions or HC3/De-Eth2 venting emissions. See detailed emission table for additional information.



**Greenhouse Gas Potential Emissions**

Process/Facility	Source ID	GHG (tpy)			
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	CO <sub>2</sub> (e)
Cryo Plant 1 Regen Heater (H-1711)	031	6,850	0.129	0.013	6,857
Cryo Plant 2 Regen Heater (H-2711)	037	10,324	0.195	0.019	10,335
<b>Cryo Plant 3 Regen Heater (H-3711)</b>	<b>038</b>	<b>12,587</b>	<b>0.237</b>	<b>0.024</b>	<b>12,600</b>
De-Ethanizer HMO Heater 1 (H-1767)	033	27,864	0.526	0.053	27,893
De-Ethanizer HMO Heater 2 (H-1768)	034	27,864	0.526	0.053	27,893
<b>De-Ethanizer 2 HMO Heater 1 (H-3767)</b>	<b>039</b>	<b>42,739</b>	<b>0.806</b>	<b>0.081</b>	<b>42,783</b>
<b>De-Ethanizer 2 HMO Heater 2 (H-3768)</b>	<b>040</b>	<b>42,739</b>	<b>0.806</b>	<b>0.081</b>	<b>42,783</b>
Stabilization HMO Heater (H-1769)	036	6,939	0.131	0.013	6,946
De-Ethanizer Regen Heater (H-1775)	035	3,820	0.072	0.007	3,824
Generac SD015	102	15.35	0.001	0.000	15
Generac SD150	102	75.65	0.003	0.001	76
Fugitives Emissions	701	0.42	7.052	-	198
Process Flare	C601	8406	49.252	0.016	9,790
<b>HC3/De-Eth 2 Venting</b>	--	<b>0.04</b>	<b>0.577</b>	--	<b>16</b>
<i>Pigging*</i>	801	-	-	-	--
<i>Blowdowns*</i>	601	-	-	-	--
<i>Drain Tank Loadout*</i>	702	-	-	-	--
<i>Regen Dry Seal Vents*</i>	602	-	-	-	--
Rod Packing	601	224	107.489	-	3,234
<b>Residue Dry Seal Vents</b>	<b>602</b>	<b>2.85</b>	<b>801.402</b>	-	<b>22,442</b>
Methanol Tanks	--	-	-	-	--
Measurement Devices	--	0.02	5.822	-	163
<b>Future Site-Wide Emissions (tpy)</b>					<b>217,849.33</b>

\* Emissions are controlled by the flare or VRU and thus, are accounted for in the process flare emissions or HC3/De-Eth2 venting emissions. See detailed emission table for additional information.

**MarkWest Liberty Midstream & Resources, L.L.C.**  
**Harmon Creek Gas Plant**

**Flare**

**Source Designation:**

Manufacturer:	John Zink
Operating Hours: (hr/yr)	8,760
Pilot + Purge Gas Heat Input (MMBtu/hr)	3.205
Pilot + Purge Gas Annual Fuel Use (mmscf/yr)	26.518
Pilot Fuel Consumption (mmscf/hr):	2.00E-04
Purge Fuel Consumption (mmscf/hr):	2.83E-03
Fuel HHV (Btu/scf)	1,059

**Combustion of Hydrocarbons**

**Source Designation:**

Annual Gas Flow (mmscf/yr)	90.00
Heating value (btu/scf)	1,282.67
Maximum Heat Release of Flare (mmbtu/yr)	115,441

**Total Emissions**

Pollutant	Emission Factor (lb/MMBtu)	lb/hr	tpy
VOC	--	2.74	12.01
NO <sub>x</sub>	0.068	1.11	4.88
CO	0.31	5.08	22.24
SO <sub>2</sub>	0.0005	0.01	0.04
PM Total	0.0064	0.10	0.46
PM Condensable	0.0048	0.08	0.34
PM <sub>10</sub> (Filterable)	0.0016	0.03	0.11
PM <sub>2.5</sub> (Filterable)	0.0016	0.03	0.11
Hazardous Air Pollutants		lb/hr	tpy
HAP	--	0.05	0.21
n-Hexane	--	0.02	0.10
Benzene	--	0.00	0.02
Toluene	--	0.01	0.03
Ethylbenzene	--	0.00	0.02
Xylene	--	0.00	0.01
Greenhouse Gases	Emission Factor (lb/MMBtu)	lb/hr	tpy
CO <sub>2</sub>	117.05	1919.25	8406.33
CH <sub>4</sub>	0.002	11.24	49.25
N <sub>2</sub> O	0.0002	0.00	0.02

<sup>a</sup> The NO<sub>x</sub> and CO emission factors are from AP-42 Section 13.5 "Industrial Flares" Table 13.5-1.

<sup>b</sup> Emission factors for GHG pollutants from 40 CFR Part 98, Subpart C. Tables C-1 and C-2.

<sup>c</sup> The remaining factors are from AP-42 Section 1.4 "Natural Gas Combustion" Tables 1.4-1 and 1.4-2.

<sup>d</sup> VOC and HAP emissions are based on mass balance.

<sup>e</sup> The flare calculations assume the composition to the flare is inlet gas.

<sup>f</sup> The open flare controls existing sources and will control the proposed sources during infrequent periods (no more than 5% of the year) when the VRU is down for maintenance.

## Fugitive Emissions

Component Type	Stream Type (Gas Vapor, Light Liquid, Heavy Liquid)	Gas Type	From LeakDAS	Number of Components <sup>a</sup>	AP-42 Leak Emission Factors kg/hr/component <sup>b</sup>	Reduction Factors <sup>c</sup>	Final Leak Factor lb/hr/component	Weight Percent <sup>e</sup>				Total	Potential VOC Emissions		Potential HAP Emissions		Potential CH4 Emissions		Potential CO2 Emissions	
								VOC	HAP	CH4	CO2	Emissions (tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Compressor	GV	CO2	2	4	8.80E-03	0%	1.94E-02	0.5%	0.1%	0.0%	100.0%	0.340	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.34
Compressor	GV	Ethane	3	6	8.80E-03	0%	1.94E-02	0.5%	0.1%	0.0%	0.0%	0.510	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Compressor	GV	Inlet	7	14	8.80E-03	80%	3.88E-03	23.9%	0.4%	77.0%	0.2%	0.238	0.01	0.06	0.00	0.00	0.04	0.18	0.00	0.00
Compressor	GV	NGL	3	6	8.80E-03	80%	3.88E-03	100.0%	0.0%	0.0%	0.0%	0.102	0.02	0.10	0.00	0.00	0.00	0.00	0.00	0.00
Compressor	GV	Purity	3	6	8.80E-03	80%	3.88E-03	100.0%	0.0%	0.0%	0.0%	0.102	0.02	0.10	0.00	0.00	0.00	0.00	0.00	0.00
Compressor	GV	Residue	12	24	8.80E-03	0%	1.94E-02	0.1%	0.0%	87.5%	0.3%	2.041	0.00	0.00	0.00	0.00	0.41	1.79	0.00	0.01
Compressor	GV	Y-Grade	3	6	8.80E-03	80%	3.88E-03	51.4%	5.3%	0.1%	0.1%	0.102	0.01	0.05	0.00	0.01	0.00	0.00	0.00	0.00
Connector	GV	Ethane	1	2	2.00E-04	90%	4.41E-05	0.5%	0.1%	0.0%	0.0%	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connector	GV	Inlet	2814	5628	2.00E-04	90%	4.41E-05	23.9%	0.4%	77.0%	0.2%	1.088	0.06	0.26	0.00	0.00	0.19	0.84	0.00	0.00
Connector	GV	NGL	304	608	2.00E-04	90%	4.41E-05	100.0%	0.0%	0.0%	0.0%	0.117	0.03	0.12	0.00	0.00	0.00	0.00	0.00	0.00
Connector	GV	Purity	605	1210	2.00E-04	90%	4.41E-05	100.0%	0.0%	0.0%	0.0%	0.234	0.05	0.23	0.00	0.00	0.00	0.00	0.00	0.00
Connector	GV	Residue	1275	2550	2.00E-04	90%	4.41E-05	0.1%	0.0%	87.5%	0.3%	0.493	0.00	0.00	0.00	0.00	0.10	0.43	0.00	0.00
Connector	GV	Y-Grade	841	1682	2.00E-04	90%	4.41E-05	51.4%	5.3%	0.1%	0.1%	0.325	0.04	0.17	0.00	0.02	0.00	0.00	0.00	0.00
Flange	GV	Ethane	2	4	3.90E-04	90%	8.60E-05	0.5%	0.1%	0.0%	0.0%	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Flange	GV	Inlet	1023	2046	3.90E-04	90%	8.60E-05	23.9%	0.4%	77.0%	0.2%	0.771	0.04	0.18	0.00	0.00	0.14	0.59	0.00	0.00
Flange	GV	NGL	99	198	3.90E-04	90%	8.60E-05	100.0%	0.0%	0.0%	0.0%	0.075	0.02	0.07	0.00	0.00	0.00	0.00	0.00	0.00
Flange	GV	Purity	82	164	3.90E-04	90%	8.60E-05	100.0%	0.0%	0.0%	0.0%	0.062	0.01	0.06	0.00	0.00	0.00	0.00	0.00	0.00
Flange	GV	Residue	573	1146	3.90E-04	90%	8.60E-05	0.1%	0.0%	87.5%	0.3%	0.432	0.00	0.00	0.00	0.00	0.09	0.38	0.00	0.00
Flange	GV	Y-Grade	414	828	3.90E-04	90%	8.60E-05	51.4%	5.3%	0.1%	0.1%	0.312	0.04	0.16	0.00	0.02	0.00	0.00	0.00	0.00
Connector	LL	Ethane	110	220	2.10E-04	90%	4.63E-05	0.5%	0.1%	0.0%	0.0%	0.045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connector	LL	Inlet	929	1858	2.10E-04	90%	4.63E-05	23.9%	0.4%	77.0%	0.2%	0.377	0.02	0.09	0.00	0.00	0.07	0.29	0.00	0.00
Connector	LL	NGL	892	1784	2.10E-04	90%	4.63E-05	100.0%	0.0%	0.0%	0.0%	0.362	0.08	0.36	0.00	0.00	0.00	0.00	0.00	0.00
Connector	LL	Purity	567	1134	2.10E-04	90%	4.63E-05	100.0%	0.0%	0.0%	0.0%	0.230	0.05	0.23	0.00	0.00	0.00	0.00	0.00	0.00
Connector	LL	Residue		0	2.10E-04	90%	4.63E-05	0.1%	0.0%	87.5%	0.3%	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connector	LL	Y-Grade	1106	2212	2.10E-04	90%	4.63E-05	51.4%	5.3%	0.1%	0.1%	0.449	0.05	0.23	0.01	0.02	0.00	0.00	0.00	0.00
Flange	LL	Ethane	86	172	1.10E-04	90%	2.43E-05	0.5%	0.1%	0.0%	0.0%	0.018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Flange	LL	Inlet	634	1268	1.10E-04	90%	2.43E-05	23.9%	0.4%	77.0%	0.2%	0.135	0.01	0.03	0.00	0.00	0.02	0.10	0.00	0.00
Flange	LL	NGL	446	892	1.10E-04	90%	2.43E-05	100.0%	0.0%	0.0%	0.0%	0.095	0.02	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Flange	LL	Purity	228	456	1.10E-04	90%	2.43E-05	100.0%	0.0%	0.0%	0.0%	0.048	0.01	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Flange	LL	Residue		0	1.10E-04	90%	2.43E-05	0.1%	0.0%	87.5%	0.3%	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Flange	LL	Y-Grade	427	854	1.10E-04	90%	2.43E-05	51.4%	5.3%	0.1%	0.1%	0.091	0.01	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	GV	Inlet	72	144	8.80E-03	97%	5.82E-04	23.9%	0.4%	77.0%	0.2%	0.367	0.02	0.09	0.00	0.00	0.06	0.28	0.00	0.00
Pressure Relief	GV	NGL	1	2	8.80E-03	97%	5.82E-04	100.0%	0.0%	0.0%	0.0%	0.005	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	GV	Purity	2	4	8.80E-03	97%	5.82E-04	100.0%	0.0%	0.0%	0.0%	0.010	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	GV	Residue	19	38	8.80E-03	97%	5.82E-04	0.1%	0.0%	87.5%	0.3%	0.097	0.00	0.00	0.00	0.00	0.02	0.08	0.00	0.00
Pressure Relief	GV	Y-Grade	6	12	8.80E-03	97%	5.82E-04	51.4%	5.3%	0.1%	0.1%	0.031	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	LL	Inlet	9	18	7.50E-03	97%	4.96E-04	23.9%	0.4%	77.0%	0.2%	0.039	0.00	0.01	0.00	0.00	0.01	0.03	0.00	0.00
Pressure Relief	LL	NGL	10	20	7.50E-03	97%	4.96E-04	100.0%	0.0%	0.0%	0.0%	0.043	0.01	0.04	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	LL	Purity	3	6	7.50E-03	97%	4.96E-04	100.0%	0.0%	0.0%	0.0%	0.013	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	LL	Y-Grade	9	18	7.50E-03	97%	4.96E-04	51.4%	5.3%	0.1%	0.1%	0.039	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00
Pump	LL	NGL	4	8	1.30E-02	85%	4.30E-03	100.0%	0.0%	0.0%	0.0%	0.151	0.03	0.15	0.00	0.00	0.00	0.00	0.00	0.00
Pump	LL	Purity	2	4	1.30E-02	85%	4.30E-03	100.0%	0.0%	0.0%	0.0%	0.075	0.02	0.08	0.00	0.00	0.00	0.00	0.00	0.00

## Fugitive Emissions

Component Type	Stream Type (Gas Vapor, Light Liquid, Heavy Liquid)	Gas Type	From LeakDAS	Number of Components <sup>a</sup>	AP-42 Leak Emission Factors kg/hr/component <sup>b</sup>	Reduction Factors <sup>c</sup>	Final Leak Factor lb/hr/component	Weight Percent <sup>c</sup>				Total Emissions (tpy)	Potential VOC Emissions		Potential HAP Emissions		Potential CH4 Emissions		Potential CO2 Emissions	
								VOC	HAP	CH4	CO2		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Pump	LL	Y-Grade	10	20	1.30E-02	85%	4.30E-03	51.4%	5.3%	0.1%	0.1%	0.377	0.04	0.19	0.00	0.02	0.00	0.00	0.00	0.00
Valve	GV	Ethane	2	4	4.50E-03	99%	9.93E-05	0.5%	0.1%	0.0%	0.0%	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Valve	GV	Inlet	1307	2614	4.50E-03	99%	9.93E-05	23.9%	0.4%	77.0%	0.2%	1.137	0.06	0.27	0.00	0.00	0.20	0.88	0.00	0.00
Valve	GV	NGL	116	232	4.50E-03	99%	9.93E-05	100.0%	0.0%	0.0%	0.0%	0.101	0.02	0.10	0.00	0.00	0.00	0.00	0.00	0.00
Valve	GV	Purity	188	376	4.50E-03	99%	9.93E-05	100.0%	0.0%	0.0%	0.0%	0.163	0.04	0.16	0.00	0.00	0.00	0.00	0.00	0.00
Valve	GV	Residue	502	1004	4.50E-03	99%	9.93E-05	0.1%	0.0%	87.5%	0.3%	0.437	0.00	0.00	0.00	0.00	0.09	0.38	0.00	0.00
Valve	GV	Y-Grade	482	964	4.50E-03	99%	9.93E-05	51.4%	5.3%	0.1%	0.1%	0.419	0.05	0.22	0.01	0.02	0.00	0.00	0.00	0.00
Valve	LL	Ethane	88	176	2.50E-03	99%	5.52E-05	0.5%	0.1%	0.0%	0.0%	0.043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Valve	LL	Inlet	646	1292	2.50E-03	99%	5.52E-05	23.9%	0.4%	77.0%	0.2%	0.312	0.02	0.07	0.00	0.00	0.05	0.24	0.00	0.00
Valve	LL	NGL	478	956	2.50E-03	99%	5.52E-05	100.0%	0.0%	0.0%	0.0%	0.231	0.05	0.23	0.00	0.00	0.00	0.00	0.00	0.00
Valve	LL	Purity	281	562	2.50E-03	99%	5.52E-05	100.0%	0.0%	0.0%	0.0%	0.136	0.03	0.14	0.00	0.00	0.00	0.00	0.00	0.00
Valve	LL	Y-Grade	604	1208	2.50E-03	99%	5.52E-05	51.4%	5.3%	0.1%	0.1%	0.292	0.03	0.15	0.00	0.02	0.00	0.00	0.00	0.00
Connector	HL	HMO		1708	7.50E-06	0%	1.65E-05	100.0%	0.0%	0.0%	0.0%	0.124	0.03	0.12	0.00	0.00	0.00	0.00	0.00	0.00
Valve	HL	HMO		569	8.40E-06	0%	1.85E-05	100.0%	0.0%	0.0%	0.0%	0.046	0.01	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Pressure Relief	HL	HMO		16	3.20E-05	0%	7.06E-05	100.0%	0.0%	0.0%	0.0%	0.005	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connector	HL	CO2		569	7.50E-06	0%	1.65E-05	0.5%	0.1%	0.0%	100.0%	0.041	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04
Valve	HL	CO2		190	8.40E-06	0%	1.85E-05	0.5%	0.1%	0.0%	100.0%	0.015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Pressure Relief	HL	CO2		5	3.20E-05	0%	7.06E-05	0.5%	0.1%	0.0%	100.0%	0.002	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connector	GV	Residue		1900	2.00E-04	90%	4.41E-05	0.1%	0.0%	87.5%	0.3%	0.367	0.00	0.00	0.00	0.00	0.07	0.32	0.00	0.00
Valve	GV	Residue		600	4.50E-03	99%	9.93E-05	0.1%	0.0%	87.5%	0.3%	0.261	0.00	0.00	0.00	0.00	0.05	0.23	0.00	0.00
			<b>18,332</b>	<b>42,221</b>								<b>Total</b>	<b>1.11</b>	<b>4.86</b>	<b>0.03</b>	<b>0.15</b>	<b>1.61</b>	<b>7.05</b>	<b>0.10</b>	<b>0.42</b>

**Notes:**

<sup>a</sup> Component counts are based on a combination of counts from LeakDas and PIDs and estimates based on studies at similar facilities.

<sup>b</sup> Table 2-4. Oil & Gas Production Operations Average Emission Factors, Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017, November 1995. Emission factors based on average measured TOC from component types indicated in gas or light oil service at O&G Production Operations.

<sup>c</sup> Table V: Control Efficiencies for LDAR for 28VHP programs, Air Permit Technical Guidance for Chemical Sources Fugitive Guidance, TCEQ (APDG 6422v2, Revised 06/2018). Compressors are monitored quarterly via OGI.

<sup>d</sup> Table 5-1. Summary of Equipment Modifications, Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017, November 1995.

<sup>e</sup> CO2 and C2 service are estimated at 0.5 VOC wt% to be conservative.