Appendix A:

List of Materials SBAR Panel shared with Small Entity Representatives

Small Business Advocacy Review Panel on EPA's Planned Proposed Rule

Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

Small Business Advocacy Review Panel
Pre-Panel Outreach Meeting with Small Entity Representatives
Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

Tuesday, May 19, 2015
EPA HQ, WJC North, room 6530
1:00 pm – 3:00 pm (eastern)

1:00 **Welcome** (EPA's Small Business Advocacy Chair, Office of Policy (OP))

1:05 **Introduction of Panel Members/Staff**
- EPA/Office of Air (OAR)
- SBA/Office of Advocacy
- OMB/Office of Information and Regulatory Affairs (OIRA)

1:10 **Introduction of SERs and Other Attendees** (OP)

1:15 **Panel Process Questions?** (OP takes questions from SERs)

1:20 **Follow-up Questions about Rule Presentation** (OAR takes questions from SERs)

1:50 **Discussion of the Rulemaking** (SERs with Panel)

2:50 **Summary and Closing** (EPA/OP)

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Teleconference dial-in number: (866) 299-3188
Conference code: 202 564 1550
Dial the toll-free teleconference number listed above. At the prompt, enter the conference code followed by the pound [#] sign. Note: You will hear music until the leader dials into the call.

An Overview of the Small Business Advocacy Review Panel Process

Pre-Panel Outreach Meeting with Potential SERs
May 19, 2014

Office of the Administrator
Office of Policy
Office of Regulatory Policy and Management
http://www.epa.gov/op/orpm.html

This presentation covers…

- What is a Small Business Advocacy Review (SBAR) Panel?
- How does a Panel fit into the rulemaking process?
- How do Small Entity Representatives (SERs) participate in the Panel process?
- What does the Panel do with SER recommendations?
- What is the difference between this Pre-Panel meeting and the future Panel meeting?

What is an SBAR Panel?

- Chaired by EPA's Small Business Advocacy Chair (EPA's SBAC from Office of Policy)
- Other Panel members consist wholly of federal employees:
  - Program Office manager;
  - Office of Management and Budget (Office of Information and Regulatory Affairs (OIRA) Administrator); and
  - Small Business Administration, Chief Counsel for Advocacy.

What is an SBAR Panel? (cont'd.)

- SBREFA[1] amended the 1980 Regulatory Flexibility Act (RFA), which requires agencies to:

  "assure that small entities have been given an opportunity to participate in the rulemaking" process for any rule "which will have a significant economic impact on a substantial number of small entities."[2]

[1] Small Business Regulatory Enforcement Fairness Act of 1996

[2] 5 USC 609(a)

What is an SBAR Panel? (cont'd.)

"the panel shall review **any material the agency has prepared**..., including any draft proposed rule, [and] **collect advice and recommendations** of each individual small entity representative ..., on issues related to"[1] the following:

- Who are the small entities to which the proposed rule will apply? [2]
- What are the anticipated compliance requirements of the upcoming proposed rule? [3]
- Are there any existing federal rules that may overlap or conflict with the regulation? [4]
- **Are there any significant regulatory alternatives that could minimize the impact on small entities?** [5]

[1] 5 USC 609(b)(4)
[2] 5 USC 603(b)(3)
[3] 5 USC 603(b)(4)
[4] 5 USC 603(b)(5)
[5] 5 USC 603(c)

Where does the Panel fit within the rulemaking process?

"any material the agency has prepared"

- The RFA requires that a Panel, if one is necessary, be conducted prior to publication of a proposed rule.
- It is EPA's policy to host Panels well before a proposed rule is written so we have adequate time to incorporate SER advice and recommendations into senior management decision-making about the proposed rule.
- EPA generally does not have draft proposed rule text available at the time a Panel is convened, though we expect to discuss regulatory alternatives in as great a detail as we can.
- Participation in the outreach meetings does not preclude, or take the place of, participation in the normal public comment period at the time the rule is proposed.

How do SERs participate?

"collect advice and recommendations"

- You have the opportunity, because of your status as a small entity who is expected to be regulated by this rule, to influence the decisions senior EPA officials make about the forthcoming regulation
- Advice and recommendations collected via two Outreach meetings with SERs:
  - EPA holds a pre-panel outreach meeting with potential SERs (this one), and
  - after the Panel convenes, the Panel itself will hold an outreach meeting with SERs.

How do SERs participate? (cont'd.)

- You will have an opportunity to submit written comments as well as the verbal comments you provide in the outreach meetings.
- Reminder: Those of you joining this meeting to assist a potential SER (aka "helpers") are asked to limit your input, both verbal and written) to representation of the small entity you are assisting.

What does the Panel do with your recommendations?

- EPA, OMB, and SBA prepare a joint Panel report:
  - Submitted to the EPA Administrator
  - Considered during senior-management decision-making prior to the issuance of the proposed rule
  - Placed in the rule's docket when the proposed rule is published

Pre-Panel vs. Panel Outreach Mtg.?

- Pre-Panel Outreach Meeting
  - Conducted by EPA with SBA and OMB as invitees
  - Overview of the RFA, how the Panel process works, and the role of SERs
  - Background and overview of proposed rulemaking
- Panel Outreach Meeting
  - Chaired by SBAC, but all Panel members have active role
  - Bulk of meeting spent discussing regulatory alternatives and input of SERs

Thank You

- We realize that small entities make significant sacrifices to participate
- Thank you for taking time and effort away from your business or organization to assist the Panel in this important work

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United States Environmental Protection Agency

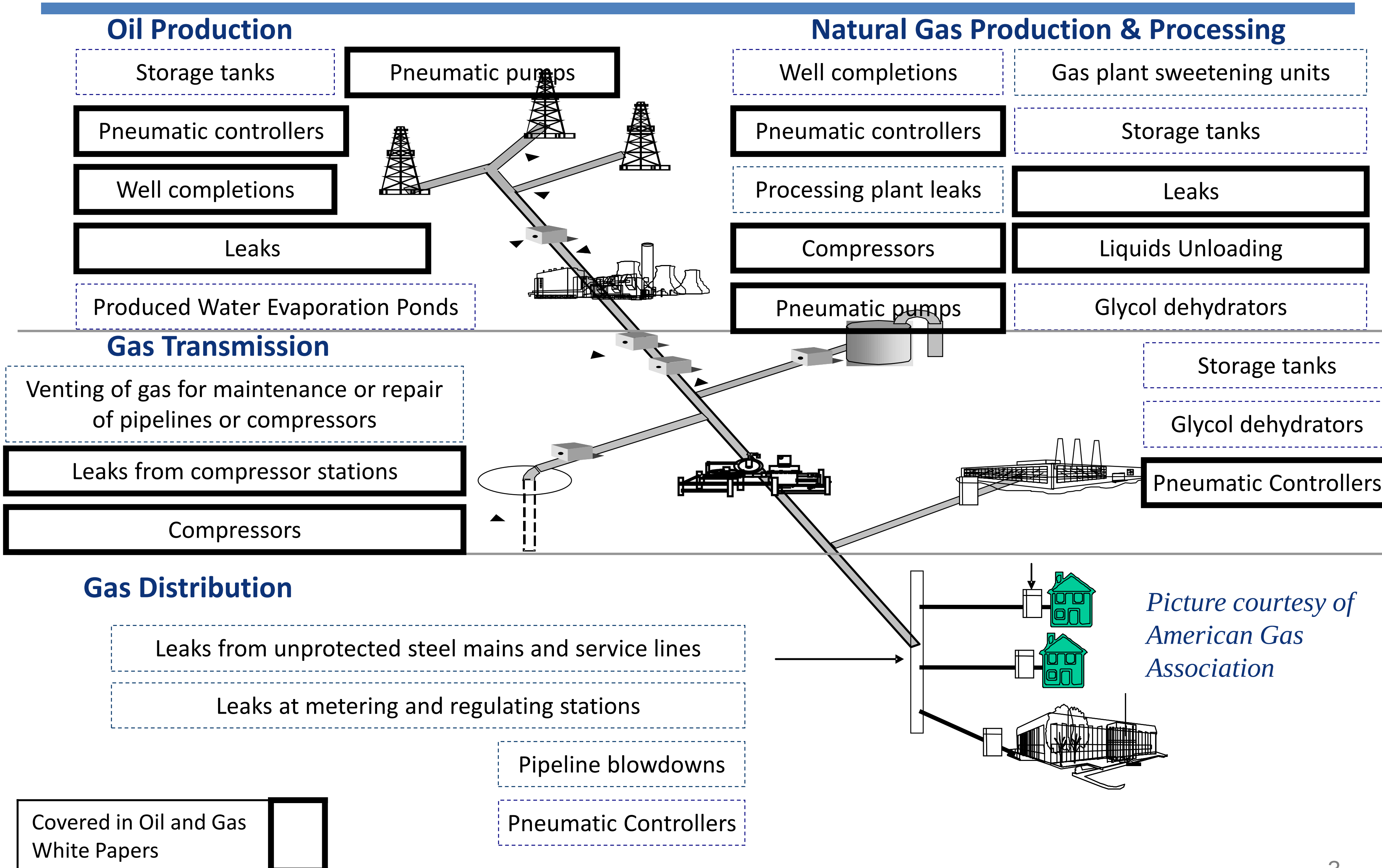
Pre-Panel Outreach Briefing: Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

May 2015

Overview

- Oil and Gas Sector Description
- What are New Source Performance Standard (NSPS)?
- Methane Strategy
- White House Announcement
- Hydraulically Fracture Oil Well Completions
- Fugitive Emissions at Well Sites, Gathering and Boosting Stations and Compressor Stations
- Pneumatic Pumps
- Pneumatic Controllers
- Compressors
- Liquids Unloading
- Potential Impacts of the Rule
- Schedule

Oil and Gas Sector Description



What are New Source Performance Standard (NSPS)?

- NSPS are technology based standards that apply to stationary sources that “cause, or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare”
- Costs are considered in the development of NSPS
- The Clean Air Act (CAA) requires EPA review, and if appropriate, revise a NSPS at least every 8 years
- April 2012 Oil and Gas NSPS
  - Regulated VOC emissions from:
    - Well completions (completed reconsideration 12/31/14 to make time-critical changes)
    - Pneumatic controllers
    - Compressors
    - Equipment leaks at gas processing plants (strengthened)
    - Storage vessels (completed reconsideration 8/2/13 to make time-critical changes)
  - Significant methane co-benefits from reductions in VOC emissions:
    - By 2015, expected to achieve reductions of about 19 to 33 million metric ton of CO2e

Methane Strategy

- Strategy to Reduce Methane Emissions released March 2014
  - Component of Obama Administration's Climate Action Plan
- Identified oil and gas sector as a key source of methane emissions (28% of emissions in 2012, second largest category)
- Outlined schedule for potential future regulation of oil and gas
  - Release five white papers: April 2014
  - Make peer review comments available:
    - Peer review complete June 2014
    - Comments currently available on white paper website
  - Determine if further regulation is necessary: January 2015
  - Complete rulemakings and state requirements if applicable: End 2016

White House Announcement

- On January 14, 2015 the White House announced its path forward on oil and gas; for the EPA the path forward included:
  - NSPS
  - Control Techniques Guidelines (CTG) Document
  - Expanded Natural Gas STAR Program
  - Consider enhancing Greenhouse Gas Reporting Program
- Specific NSPS commitments
  - Reduce emissions of GHGs and VOCs
  - Add equipment and processes to those source types currently covered by NSPS standards
    - Specifically look at sources from the Oil and Gas White Papers
  - Schedule
    - Proposal: Summer 2015
    - Final: Spring 2016

Hydraulically Fractured Oil Well Completions

- Emissions occur as wells "flowback" during the completion process
- Available studies estimate emissions (see Oil Wells white paper pg 44):
  - Methane: 44,000 tons per year to 247,000 tons per year
  - VOC: 37,000 tons per year to 116,000 tons per year
- Reduced emission completions ("green completions") (see Oil Wells white paper pg 23):
  - Gas is captured when feasible and flared when infeasible
  - Results in gas capture for wells that have access to pipeline infrastructure
  - Reduces emissions by 95% or about 7 tons methane and 6 tons VOC per completion
  - Currently a common practice in the field
  - Approximate cost: $20,000 per completion (depends on duration)
    - Cost estimate based on contracting with specialized service providers
- Completion combustion ("flaring") (see Oil Wells white paper pg 27)
  - Pipeline infrastructures is unnecessary
  - Reduces emissions by 95% or about 7 tons methane and 6 tons VOC per completion
  - Does not result in gas capture
  - Secondary impacts from flaring: NOx, CO, and PM
  - Approximate cost: $4,000 per completion
    - Cost estimate based on conservative assumption of purchasing a combustion device for each completion
- Some states require green completions in combination with flaring
  - WY, CO

Fugitive Emissions at Well Sites, Gathering and Boosting Stations and Compressor Stations

- Multiple sources of fugitive emissions at well sites, gathering and boosting stations, and compressor stations
  - Valves, connectors, open-ended lines, pressure relief valves, thief hatches on tanks, etc
- Available studies estimate emissions (see Leaks white paper pg 17):
  - Methane: 333,000 MT from gas production, 34,000 MT from gas processing, and 114,000 MT from gas transmission
  - Leaks at facility may range from about 5 to 160 tons per year methane or 1 to 10 tons per year VOC depending on where in the supply chain the emissions occur
  - Reductions at facility may range from about 3 to 100 tons per year methane or 1 to 6 tons per year VOC
- Several technologies are available to find and fix these sources
  - Infrared cameras
  - Portable analyzers
  - Acoustic leak detectors
  - Ambient/mobile monitoring
- Estimated costs depend on several factors (see Leaks white paper pg 36):
  - Detection technologies
  - Frequency of detection surveys
  - Size and type of site (e.g., well site, gathering and boosting station, compressor station)
  - $1,500 to $20,000 per facility per year depending on type of facility
  - Cost estimate based upon sum of expected company-level activities (planning, reporting, and recordkeeping, for example) and site-level costs based on contracting with specialized service providers
- Several states require monitoring and repair of these emission sources
  - WY, CO, OH, PA, UT

Pneumatic Pumps

- Emissions are vented when pneumatic pumps operate
- Multiple types of pneumatic pumps
  - Chemical/methanol injection pumps
    - Small and very common at well sites
  - Diaphragm pumps
    - Similar to chemical/methanol injection pumps but larger
  - Gas assist pumps (glycol pumps)
    - Used on glycol dehydrators to circulate the glycol
    - Emissions come from the same vent as the rest of the glycol dehydrator emissions
    - Currently regulated as part of the National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Available studies estimate emissions (see Pneumatic Devices white paper pg 32):
  - 115,000 MT methane from chemical/methanol and diaphragm pumps
  - 393,000 MT methane from gas assist pumps
- Control options
  - Reductions range from 95% to 100% depending on control option, or about 0.5 to 4 tons methane per year and 0.1 to 1.0 tons VOC per year on a facility basis
  - Combust emissions (e.g., flare)
  - Capture through a vapor recovery unit
  - Install non-emitting pumps (e.g., solar, instrument air or electric)
- Estimated costs
  - Cost to combust or capture is low if controls are already on site: about $2000 for purchase and installation of piping
  - Cost of solar pumps similar to installing a new pneumatic pump but they may not be technically feasible in all situations
- WY regulates emissions from pneumatic pumps

Pneumatic Controllers

- Continuous bleed gas driven pneumatic controllers “bleed” as part of normal operation
- Available studies estimate emissions (see Pneumatic Devices white paper pg 13):
  - Methane: 770,000 MT from oil and gas production, 2,000 MT from gas processing, and 250,000 MT from gas transmission and storage
- 2012 NSPS regulated continuous bleed pneumatic controllers in production/processing but not transmission/storage
  - Production: Set an emission limit of 6 scf/hr (i.e., “low bleed”)
  - Processing: Set an emission limit of 0 scf/hr (i.e., instrument air or electric controllers)
- Control options (see Pneumatic Devices white paper pg 36):
  - Install “low” bleed controllers
    - Reduces emissions by >90% in most cases, or about 6 tons methane per year or 0.2 tons per year VOC
  - Install non-emitting controllers (e.g., solar, instrument air or electric)
    - Requires reliable access to electricity
    - Reduces emissions by 100%, or about 6 tons methane per year or 0.2 tons per year VOC
- Estimated costs (see Pneumatic Devices white paper pg 36):
  - $30 to install a low bleed controller instead of a high bleed, based on annualized cost of controller with capital costs of around $230
- Many states regulate emissions from pneumatic controllers

Compressors

- Wet seal centrifugal compressors vent emissions when degassing compressor seals
- Reciprocating compressors vent emissions from the rod packing
- Available studies estimate emissions (see Compressors white paper pg 18):
  - Methane: 86,000 MT from gas production, 724,000 MT from gas processing, and 1,261,000 MT from gas transmission and storage
- 2012 NSPS regulated compressors in production/processing but not transmission/storage; argued low total VOC emissions
  - Wet seal centrifugal compressors: 95% control for new and modified wet seal compressors
  - Reciprocating compressors: Rod packing replacement every 26,000 hours or route emissions to a process
- Control options (see Compressors white paper pg 29):
  - Controls reduce about 20 to 140 tons methane per year and 1 to 4 tons VOC per year depending on type of compressor and control
  - Combust emissions (e.g., flare)
    - $100,000 annualized cost per compressor
  - Capture through a vapor recovery unit (VRU)
    - $20,000 annualized cost (without considering gas savings) per VRU; net savings when recovered gas is considered
  - Install dry seals instead of wet seals
    - Net savings when gas savings and reduced O&M costs are considered
  - Replace reciprocating compressor rod packing
    - $2,000 to $7,000 per compressor each time the rod packing is replaced
- Many states regulate emissions from compressors

Liquids Unloading

- In mature gas wells, the accumulation of liquids in the well can impede and sometimes halt gas production
- Certain techniques for removing this liquid result in venting the well to atmosphere
  - These techniques vary depending on well characteristics
- Available studies estimate emissions:
  - Methane: 270,000 MT to 320,000 MT (see Liquids Unloading white paper pg 8)
- 2012 NSPS did not regulate this source
- Phase 2 of the UT Methane Study was released in December 2014 and directly measured emissions
- Control options (see Liquids Unloading white paper pg 14)
  - Plunger lift systems with and without smart automation
    - $2,000 (without smart automation) to $20,000 (with smart automation)
  - Artificial lifts (e.g., pump jacks)
    - $41,000 to $62,000
  - Velocity tubing
    - $7,000 to $64,000
  - Foaming agents
    - $500 to $9,880
- CO regulates emissions from liquids unloading

Potential Impacts of the Rule

- Evaluating appropriateness of setting GHG and/or VOC standards for each of the white paper sources
- Ways EPA can ease impact to industry
  - Avoid regulating good behavior
    - Low bleed controllers or zero-bleed pneumatic controllers
    - Dry seal compressors
    - Zero emission pneumatic pumps
    - Sites with low fugitive emissions
  - Incentive technologies that capture rather than flare gas, resulting in economic benefit for the owner/operator
    - RECs
    - Dry seal compressors
    - Low bleed pneumatic controllers
    - Zero emission pumps
    - Finding and fixing leaks

SER Input Requested

- Is there any information that would improve our understanding of the number of small entities that could be affected by this action?
- What recommendations do you have for reducing recordkeeping and reporting burden on small businesses?
- Are there other federal rules that apply to small businesses that may overlap with this action?
- What recommendations do you have to reduce the burden to small businesses while reducing emissions from the white paper sources?
  - Oil well completions
  - Fugitive emissions
  - Pneumatic pumps
  - Pneumatic controllers
  - Compressors
  - Liquids unloading

Schedule

Milestones	Dates
Convene SBAR Panel	Spring 2015
Complete SBAR Panel	Summer 2015
Proposal Signature	Summer 2015
Final Signature	Spring 2016

Potential Small Entity Representatives - Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector[1]

Name	Affiliation	Contact Information
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Robert Mitchell Vice President	Carrera Gas Companies LLC Oklahoma	rmitchell@carreragas.com 918-710-4128
Arthur Stewart President	Cameron Energy Company Pennsylvania	camelot1@atlanticbb.net 814-968-3337

[1] Gas Processors Association, represented by Matt Hite and Mark Sutton; and Independent Petroleum Association of America, represented by Matt Kellogg will serve as Helpers.

[2] Pam Lacey from American Gas Association will serve as Tom's helper

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[3] Dave Ochs and Roy Rakiewicz will serve as Helpers.

Oil and Natural Gas White Papers
Abridged Summary

Prepared for the Small Business Advocacy Review Panel

US EPA Office of Air Quality Standards

May 18, 2015

1.0 Introduction

1.1 Purpose of this Document

On April 15, 2014, the EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector. The white papers presented the Agency's understanding of emissions and available emissions mitigation techniques from potentially significant sources of emissions in the oil and natural gas sector. Specifically, the white papers focus on technical issues covering emissions and mitigation techniques that target methane and volatile organic compounds (VOCs) for following emission sources:

- Oil well completions and ongoing production
- Leaks
- Compressors
- Pneumatic devices
- Liquids unloading

The EPA conducted an independent peer review of the white papers as well as welcomed submittal of technical information and data from the public.

This document provides an abridged summary of the content of the white papers and a high level overview of the comments submitted by the peer reviewers.

Both the white papers and peer reviewer comment are available for review at http://www.epa.gov/airquality/oilandgas/whitepapers.html.

1.2 Peer Reviewers

Table 1 provides a list of the peer review panel that provided comment to the EPA on the individual whitepapers.

Table 1. White Paper Peer Review Commenters

Commenter	Affiliation	White Paper Reviewed
David Allen	University of Texas	All
Ramon Alvarez, Robert Harriss, and David Lyon	Environmental Defense Fund	All
Joe Cardena	XTO Energy, Inc.	Oil Well Completions
Ned Jerabek	New Mexico Environmental Department	Oil Well Completions, Compressors and Pneumatic Devices
Karen Olsen	Southwestern Energy	Oil Well Completions
Steven Prince	Division of Natural Resources, Navajo Nation	Oil Well Completions
Matthew Harrison	URS Corporation	Upstream Leaks
Doug Jordan	Southwestern Energy	Upstream Leaks
David Picard	Clearstone Engineering Ltd.	Upstream Leaks
Curtis Taipale	Colorado DPHE	Upstream Leaks
Gary Reeves	Pioneer Natural Resources	Compressors
John Cordaway	Transcanada Corporation	Compressors
Jim Bolander	Southwestern Energy	Pneumatic Devices and

		Liquids Unloading
Carrie Reese	Pioneer Natural Resources	Pneumatic Devices
Gordon Reid Smith	Independent Consultant BP America Production Co.	Liquids Unloading

2.0. Oil Well Completions and Ongoing Production

2.1 Description of Process:

The white paper addresses VOC emissions estimates and control technologies completions and associated gas from ongoing production at hydraulically fractured oil wells. Hydraulic fracturing is one technique for improving oil and gas production where the reservoir rock is fractured with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Completion operations with hydraulic fracturing are conducted to either bring a new oil well into the production phase or to maintain or increase the well's production capability (sometimes referred to as a recompletion). Well completions with hydraulic fracturing 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 are installed as necessary for production to begin.

The emissions from completions are a result of the backflow of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This comingled fluid stream (containing produced oil, natural gas and water) flows from each drilled well to a respective vertical separator and heater/treater processing unit. Phase separation is the process of removing impurities from the hydrocarbon liquids and gas to meet sales delivery specifications for the oil and natural gas. If infrastructure is present, produced gas can be metered to a sales pipeline. If infrastructure is not available, the produced gas is frequently sent to combustion devices for destruction (e.g., flares) or is vented to the atmosphere.

Associated gas is the term typically used for natural gas produced as a by-product of the production of crude oil. Industry publications typically refer to associated gas as gas that is coproduced with crude oil while the well is in the production phase and is vented directly to the atmosphere or is flared. Therefore, associated gas can include gas that is produced during flowback associated with completion activities and gas that is emitted from equipment as part of normal operations, such as natural gas driven pneumatic controllers and storage vessels.

2.2 Emissions Data

The white paper describes the processes used to estimate emissions from oil well completions. Because limited direct measurement of emissions has been conducted, these processes rely on data produced for other purposes. These data include estimated gas produced during completions, gas produced by the well over a certain production period, gas composition data from analysis of various gas streams, and data on duration of completion cycles. Various elements of these data are provided in various studies and information sources presented below.

Source of Data	Fort Berthold Federal Implementation Plan, 2012
Emissions Source Description	From 154 synthetic minor permit applications for oil wellheads, heater/treaters and storage tanks, representing 533 production wells, five major operators
Type of Data:	Estimated VOC emissions from above sources, oil production data, number of storage

	tanks, combustors, flares and presence of a pipeline, cost data for combustion and REC controls, gas composition data, projected number of new wells pad per year between 201 and 2019
Emissions Estimation/ Measurement	Measured gas composition data; calculated VOC emissions using gas composition and oil production data and emission factors for oil wells from GRI/EPA study.
Methane or VOC emission factors/ emissions findings	No new emission factors developed. However, the study of the data provided an opportunity to analyze production data and emissions information to determine potential completion emissions.
Applicability to ONG Sector	Although a large data set, data was regionally based in two formations. Gas composition and production had high variability and also may differ from what would be found nationally.
Source of Data	ERG/ECR Contractor Analysis of HPDI® Data, 2013
Emissions Source Description	Hydraulically fractured oil wells
Type of Data:	HPDI data on number of hydraulically fractured oil well completions, CY 2011, average daily flow of oil, 192 data points representing county level average daily natural gas production at 5,754 oil well completions
Emissions Estimation/ Measurement	Using HPDI oil well data and GRI/EPA gas composition data, calculated methane and VOC emissions from 7 and 3 day completion durations. Using data from Colorado, Texas and Wyoming state reported data, calculated percentage of existing wells undergoing recompletion annually.
Methane or VOC emission factors/ emissions findings	Average gas production of 262 Mcf per well per day. Uncontrolled VOC emissions were 20 tons per completions event (7-day) and 6.4 tons per event (3-day). Methane emissions were 24 tons per vent (7-day) and 7.7 tons per event (3-day). Nationwide emissions were estimated using well count data from HDPI. Estimated that 0.5% of existing oil wells undergo recompletion annually.
Applicability to ONG Sector	Gas production from hydraulically fractured oil wells. Assumes no control applied. Nationwide level of use of RECs or combustors on oil well completions was not available.
Source of Data	Environmental Defense Fund Analysis of HPDI® Data, 2014
Emissions Source Description	Oil well completions in Bakken, Eagle Ford and Wattenberg formations.
Type of Data:	HPDI data: 3,694 oils in Bakken, 1,797 oil wells in Eagle Ford, and 3,967 oil wells in Wattenberg, initial gas production, natural gas methane content.
Emissions Estimation/ Measurement	Estimated uncontrolled demission from oil well completions for each formation
Methane or VOC emission factors/ emissions findings	10.5 tons of methane per completion event for Wattenberg, 19.8 tons of methane per completions event for Bakken and 27.2 tons of methane per completion event for Eagle Ford.
Applicability to ONG Sector	Re-evaluation of HDPI data indicating similar findings as other analysis conducted by EPA, with the exception of formation specific focus.
Source of Data	Measurements of Methane Emissions at Natural Gas Production Sites in the United States, 2013
Emissions Source Description	Academic/industry study to measure emissions from several oil and natural gas production sources, including gas and oil well completions
Type of Data:	6 oil wells - oil produced, gas produced, gas-to-oil ratio, gas composition, type of emissions controls used, percent reduction for the controls used, and duration of completion events
Emissions Estimation/ Measurement	Measured oil production and gas production, calculated methane and VOC emissions, measured gas composition and calculated emission reduction percentage for controls

	used. Assumed a gas to oil ratio of 12,500 scf/barrel to distinguish oil wells from gas wells.
Methane or VOC emission factors/ emissions findings	Average duration 72 hours or 3 days. Average uncontrolled methane was 213 tons and average controlled was 3.2 tons. One well controlled using a REC reported 98.8 percent reduction.
Applicability to ONG Sector	Only measured data available for completion events. However, sample size very small.
Source of Data	Methane Leaks from North American Natural Gas Systems, 2013
Emissions Source Description	Hydraulically fractured oil wells drilled in 2010 or 2011 in Eagle Ford, Bakken and Permian formations
Type of Data:	HPDI data: oil well counts, oil production, gas production
Emissions Estimation/ Measurement	O'Sullivan method, peak gas production (normally within first month) is converted to a daily rate and emissions increase linearly over the first 9 days of completion until peak rate is reached.
Methane or VOC emission factors/ emissions findings	Eagle Ford, uncontrolled methane 93 tons per event, Bakken 31.9 tons per event and Permian 31.9 tons per event.
Applicability to ONG Sector	Contrast to calculation used in ERG/ECR analysis using same type of data.

The white paper also discusses two approaches that could potentially be used for estimating associated gas from oil wells. One method is using the gas-to-oil ratio of the well to develop an emission factor that would be applied to know oil production data. However, the dynamics of gas reduction over the life of oil production would need to be considered. The second approach be to use gas production data reported by the well for economic or regulatory reasons. However, the data would not provide insight as to what was capture/controlled or vented. The two sources of data discussed for associated gas were the Greenhouse Gas Reporting Program and a North Dakota flaring study. Neither of those sources were noted as providing information that would be nationally representative or robust enough to determine emissions of associated gas.

2.3 Mitigation Approaches

Approach	Reduced Emission Completions (REC)
Description	A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, reinjected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere
Applicability	Applicable at most gas producing oil wells. Limitations include proximity of the wall to a gas pipeline, sufficient volume and pressure of produced gas, and inert gas concentration in flowback gas.
Costs	Per Natural Gas STAR study, average costs for a REC average cot so $4,146 per day. Total cost depends on length of flowback period. A 7-day completion would cost $29,022. These costs do not consider gas savings.
Efficacy and Prevalence	Depends on well and reservoir characteristics, however, per Natural Gas STAR study, the efficiency is estimated at 90 percent emissions reduction. No significant data is available on the prevalence of the use of RECs for oil well completions.
Approach	Completion Combustion Devices
Description	High temperature oxidation of hydrocarbons in the gas stream. Include flares and enclosed combustors.
Applicability	Generally applicable to all oil well sites.
Costs	Average cost for an enclosed combustor $18,092.
Efficacy and	95 percent reduction with a continuous ignition source. Generally one combustion device

Prevalence	theoretically can service multiple wells. Some data suggests common use in the industry.

2.4 Peer Review Opinion

The peer reviewers generally agreed with the use of gas production data as a reasonable basis for estimating emissions but differed significantly on how that parameter could be used. Most commenters indicated that annual production was not appropriate and initial production was also not appropriate. Reviewers noted that the flowback gas has different dynamics and concentration than production gas because of the change in the reservoir after removal of fracking fluids from the well. All commenters indicated that a more diligent effort should be put into determining the duration of flowback, specific to oil wells as it determines both emissions and costs for application of RECs and the effectiveness of them, and that duration of flowback period at oil wells used in the EPA estimates is unsupported with data in the white paper. Reviewers reiterated the high variability of all parameters need to estimate emission from completions and the need to further study and establish data that directly relates to the operation. Reviewers pointed out that EPA has misconstrued recompletion versus refracturing and that the latter is what they are actually addressing in the white paper. Most reviewers indicated that industry is currently controlling some emissions from completions and noted methods to more fully quantify those data. For the most part, industry reviewers believed the emissions estimates to be overstated and the environmental and state reviewers noted that they were understated.

3.0 Fugitive Emissions (Leaks)

3.0 Oil and Natural Gas Sector Leaks (Fugitive Emissions)

3.1 Description of Process:

The emissions data and the mitigation techniques presented in the White Paper are applicable to natural gas fugitive emissions from natural gas production, processing, transmission, and storage. Some of these emissions estimates and mitigation techniques are also applicable to oil wells that co-produce natural gas. For the purposes of the White Paper, *fugitives* were defined as VOC and methane emissions that occur at onshore facilities upstream of the natural gas distribution system (i.e., upstream of the city gate). This includes fugitive emissions from natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of fugitive emissions from these sites include agitator seals, compressors seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves, and improperly controlled liquids storage. Emissions from equipment intended to vent as part of normal operations, such as gas driven pneumatic controllers, are not considered leaks. The definition of fugitive emissions in the White Paper was derived by reviewing the various approaches taken in the available literature.

Fugitive emissions occur through many types of connection points (e.g., flanges, seals, threaded fittings) or through moving parts of valves, pumps, compressors, and other types of process equipment. Changes in pressure, temperature and mechanical stresses on equipment may eventually cause them to leak. Fugitive emissions can also occur when connection points are not fitted properly, which causes leaks from points that are not in good contact. Other leaks can occur due to normal operation of equipment, which, over time, can cause seals and gaskets to wear. Weather conditions can also affect the performance of seals and gaskets that are intended to prevent leaks. Lastly, fugitive emissions can occur from equipment that is not operating correctly, such as storage vessel thief hatches that are left open or separator dump valves that are stuck open.

3.2 Emissions Data

Source of Data	Protocol for Equipment Leak Estimates, 1995
Emissions Source Description	Provides standard procedures for estimating TOC mass emissions from leaks at refineries, marketing terminals, oil and gas production operations and SOCMI facilities.
Type of Data:	Correlation equations and emission factors were developed from leak data collected for valves, pumps, compressors, pressure relief valves, connectors, flanges and open-ended lines. Development of emission factor and correlation equations for the oil and natural gas production facilities were derived from data from 6 gas plants and from leak emission measurement data from 24 oil and natural gas production facilities.
Estimation/ Measurement	Provides 4 approaches for estimating leak mass emissions from these sites; average emission factor, screening range, EPA correlation and unit specific correlation approach.
Methane or VOC emission factors/ emissions findings	The emission factors and correlation equations provide equipment leak emissions in units of kilograms TOC/hr per individual piece of equipment. Methane and VOC would be estimated using composition and weight ratios.
Applicability to ONG Sector	The data available in the Protocol document are for natural gas production facilities. Based on the data available, only the average emission factor approach could be used for estimating methane and VOC leak emissions.
Source of Data	GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, 1996
Emissions Source Description	Provides an estimate of annual methane emissions from leaks from the natural gas production sector using component counts and methane emission factors.
Type of Data:	Correlation equations and emission factors were developed from leak data collected for valves, pumps, compressors, pressure relief valves, connectors, flanges, open-ended lines and sampling connections.
Estimation/ Measurement	All components screened following EPA Method 21. GRI Hi-Flow used to determine emission factors for some offshore production sources. For onshore natural gas production, facilities were broken into eastern and western categories, to account for regional differences in methane content of the natural gas.
Methane or VOC emission factors/ emissions findings	The study estimated that 15,512 million standard cubic feet per year (MMscf/yr) of methane are emitted as leaks from 271,928 onshore natural gas production wells in the U.S. for the 1992 base year.
Applicability to ONG Sector	The study used two approaches to estimate component emissions for the onshore natural gas production, offshore natural gas production, natural gas processing, natural gas transmission and natural gas storage segments.
Source of Data	Greenhouse Gas Reporting Program (GHGRP), 2013
Emission Source Description:	Requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.
Type of Data:	Covers a subset of national emissions, as facilities are required to submit annual reports only if total GHG emissions are 25,000 metric tons CO2e or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors.
Estimation/ Measurement	Methods for calculating emissions from leaks depend on industry segment. Onshore production facilities use population counts and population emission factors. Facilities in the onshore gas processing and gas transmission segments use counts of leaking components and leak emission factors.
Methane or VOC emission factors/ emissions findings	For the 2012 reporting year, reported methane emissions from leaks from onshore petroleum and natural gas production were 364,453 MT, onshore natural gas processing were 13,527 MT, and onshore natural gas transmission compression were 15,868 MT.
Applicability to ONG Sector	The 2012 GHG data for Petroleum and Natural Gas Systems was collected under the GHGRP.
Source of Data	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)
Source Description:	Tracks total U.S. GHG emissions and removals by source and by economic sector over a time series, beginning with 1990. The GHG Inventory includes estimates of methane and CO_2 for natural gas and petroleum systems.

Type of Data:	Covers all equipment that process or transport natural gas from oil and gas production sites. The segment is broken into six regions and includes estimates for gas wells, separation equipment, gathering compressors, gathering pipelines, drilling and well completions, normal operations, condensate tank vents, well workovers, liquids unloading, vessel blowdowns, and process upsets.
Estimation/ Measurement	Emission factors from the GRI/EPA adapted in the 2014 GHG Inventory for each of the NEMS regions based on-specific methane content in produced natural gas.
Methane or VOC emission factors/ emissions findings	Estimated 332,662 MT of potential methane leak emissions from gas wells and field separation equipment from natural gas production activities in 2012; 33,681 MT of potential methane emissions from gas processing leak emissions and 114,348 MT of potential methane emissions from gas transmission leak emissions; and estimates that potential emissions from leaks in production, processing and transmission are approximately 480,691 million MT of methane or about 8% of overall potential methane emissions from oil and gas.
Applicability to ONG Sector	Facility-level data reported, limited due to reporting threshold.
Source of Data	Measurements of Methane Emissions at Natural Gas Production Sites in the United States, 2013
Emissions Source Description	An academic study to gather methane emissions data at onshore natural gas sites in the U.S.
Type of Data:	Leak emissions from piping, valves, separators, wellheads and connectors.
Estimation/ Measurement	Identification of fugitives using OGI camera. The flow rate and the concentration of the leaks were measured using a Hi-Flow Sampler™ and the mass emission rate calculated. Based on the gas composition, the percentage of carbon accounted for by methane in the sample stream was determined.
Methane or VOC emission factors/ emissions findings	Average values of leak emissions per well reported are comparable to the average values of potential emissions per well for gas wells, separators, heaters, piping and dehydrator leaks (0.072 scf methane/min/well) from the 2013 GHG Inventory, calculated by dividing the potential emissions in these categories in the 2013 GHG Inventory by the number of wells.
Applicability to ONG Sector	Limited sample size, however, data can be used as benchmark.
Source of Data	City of Fort Worth Natural Gas Air Quality Study, 2011
Emissions Source Description	Conducted on behalf of City to determine level of air pollution is being released by natural gas exploration in Fort Worth, the compliance status of the sites, offsite impacts of emissions, and adequacy of city-mandated setbacks.
Type of Data:	Collected ambient air monitoring and direct leak and vented emissions measurements and performed air dispersion modeling using data from 375 well pads, 8 compressor stations, a gas processing plant, a saltwater treatment facility, a drilling operation, a hydraulic fracturing operation, and a completion operation.
Estimation/ Measurement	Identification and measurement with OGI, TVA, a Hi-Flow Sampler™ and stainless steel canisters. Measurements for each site and 10% of the total valves and connectors and the other components by TVA to determine leaks at or above 500 ppmv. Gas samples from selected leaks were collected in stainless steel canisters for VOC and HAP analysis by a gas chromatograph/mass spectrometer (GC/MS).
Methane or VOC emission factors/ emissions findings	Estimated the total organic emissions to be 20,818 tons per year or 18,819 Mg/yr, with well pads accounting for more than 75% of the total emissions. Hydrocarbons with low toxicities accounted for approximately 98% of the emissions.
Applicability to ONG Sector	Specific to air quality issues associated with natural gas exploration and production. Limited due to geographic concentration and sample size.
Source of Data	Measurements of Well Pad Emissions in Greeley, CO, 2012
Emissions Source Description	23 well pads in areas near Greeley, CO (Weld County).
Type of Data:	The average production pad consisted of 5 wells, 258 valves, 2,583 connectors, 3 condensate tanks, 1 produced water tank, 4 thief hatches, 5 pressure relief devices, 3 separators and 1 enclosed combustor control device.

Estimation/ Measurement	93 emission points were identified with OGI technology at the 23 production sites and emission rates were measured using a high volume sampler with a subset of 33 additionally sampled using evacuated canisters. A disproportionate number of detected emissions were found to be associated with storage tanks (72%).
Methane or VOC emission factors/ emissions findings	Authors concluded condensate tank-related emissions observed in the Greeley study were not effectively collected and controlled. Due to single point and instantaneous nature of the measurements, unknown if these uncollected emissions exceed the state allowance. Considering only emissions measurements with canister analysis, average methane emissions from all storage tanks, excluding samples of known flash emissions, were much lower in the Greeley study compared to the Fort Worth study. Average VOC tank related emissions were much higher in the Greeley compared to Fort Worth study. Non-tank emissions followed similar trends.
Applicability to ONG Sector	The objectives of the limited scope Greeley well pad study were to improve understanding of methane and speciated VOC emissions and investigate the use of commercially available non-invasive measurement approaches for application to wet gas production operations (including tank emissions).
Source of Data	Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, 2013
Emissions Source Description	Components at gas processing plants, compressor stations and well sites.
Type of Data:	Leak rates, types of leaking components
Estimation/ Measurement	Identification of fugitives using OGI and measurement using a high-volume sampler. In some cases, an estimate (evaluated using OGI) was used to make the decision to repair.
Methane or VOC emission factors/ emissions findings	Study found of the 58,421 components identified in the surveys, 39,505 (68%) were either leaking or venting gas. Gas processing plants had the highest leak rate, followed by compressor stations and then well sites. The study noted that vents are the most common source of gas emissions from the identified emission sources, and about 40% of the vent emissions come from instrument controllers and compressor rod packing.
Applicability to ONG Sector	The study results show that, for the facilities in the study, gas processing plants are the most likely to have leaks and the most likely to have large leaks, followed by compressor stations, and, lastly, well sites.
Source of Data	Mobile Measurement Studies in Colorado, Texas, and Wyoming, 2012
Emissions Source Description	Oil and natural gas facilities (well pads and compressor stations)
Type of Data:	OTM 33A readings for methane and canister analysis for VOC in the Fort Worth area, WY, 93 and CO, and TX.
Estimation/ Measurement	OTM 33A ambient air sampler, some canisters were analyzed for VOC.
Methane or VOC emission factors/ emissions findings	Preliminary results show median methane emission rates of 0.21 g/s, 0.43 g/s and 0.79 g/s and VOC emission rates of 0.16 g/s, 0.04 g/s and 0.30 g/s for the CO, TX, and WY studies, respectively (excluding Eagle Ford).
Applicability to ONG Sector	Ambient air sampling technique can show presence, however, not quantifiable as a source-specific tool.
Source of Data	Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, 2014
Emissions Source Description	22 methane emission sources in the oil and natural gas industry including well site leaks (includes heaters, separators, dehydrators and meters/piping) and pipeline leaks.
Type of Data:	Analysis if existing 2013 GHG Inventory for methane emissions data for the oil and natural gas sector revised to include updated information from the GHGRP and other studies.
Estimation/ Measurement	The 2011 baseline methane inventory wellhead emission factor for well sites, 97.6 scf/day used to estimate the total methane leak emissions from well sites. Leak emissions from heater, separators, dehydrators, and meters/piping in the natural gas production sector were calculated using the GRI/EPA factors.
Methane or VOC emission factors/ emissions findings	Estimated14 billion cubic feet (264,000 MT) of methane emissions from wellheads in comparison; 15 billion cubic feet (283,000 MT) from heaters, separators, dehydrators and meters/piping; and 3 billion cubic feet (56,600 MT) from processing facilities.

Applicability to ONG Sector	Some discussion of emissions levels and potentially cost-effective approach to reduce methane emissions from the industry.
Source of Data	Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants, 2002 and Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites,, 2006
Emissions Source Description	4 gas processing plants in the western U.S. and 5 gas processing plants, 12 well sites, and 7 gathering stations in the U.S
Type of Data:	Screening data or engineering calculation of gas flows into the vent and flare systems; Screening data on 101,193 individual gas service components were screened, along with 5 process vents, 28 engines, 7 process heaters, and 6 flare/vent systems and screening data for gas service equipment components at 24 sites
Estimation/ Measurement	Bubble tests with soap solution, portable hydrocarbon gas detectors, and ultrasonic leak detectors using a 10,000 ppm leak definition. Leak rates were measured using a Hi-Flow™ Sampler or bagging or other direct measurement techniques.
Methane or VOC emission factors/ emissions findings	Approximately 2.6 percent of screened components were determined to be leaking. The study states that "components in vibrational, high-use or heat- cycle gas service were the most leak prone." The majority of the leaks were attributed to a relatively small number of leaking components.
Applicability to ONG Sector	Component specific information and provided an analysis of the payback periods for fixing the identified leaks.

3.3 Mitigation Approaches

Approach	Portable Analyzers
Description	A portable monitoring instrument is used to detect hydrocarbon leaks from individual pieces of equipment.
Applicability	Portable analyzers can be used to estimate the mass emissions leak rate by converting the screening concentration in ppm to a mass emissions rate by using the EPA correlation equations from the Protocol for Equipment Leak Emission Estimates. The correlation equations in the Protocol can be used to estimate emissions rates for the entire range of screening concentrations, from the detection limit of the instrument to the "pegged" screening concentration, which represents the upper limit of the portable analyzers.
Costs	Costs vary based on the type of analyzer used to measure leak concentrations. The documentation for the EPA National Uniform Emission Standards for Equipment Leaks (40 CFR part 65, subpart J) provides a cost of $10,800 for a portable monitoring analyzer (RTI, 2011). Additional costs would also include labor costs associated with performing the screening and would depend on the number of components screened.
Efficacy and Prevalence	The portable analyzers must be calibrated using a reference gas containing a known compound at a known concentration. Methane in air is a frequently used reference compound. The portable monitoring instruments operate on a variety of detection principles, with the three most common being ionization, IR absorption and combustion. The typical types of portable analyzers used for detecting leaks from components are OVAs and TVAs.
Approach	Optical Gas Imaging (IR Camera)
Description	Uses spectral wavelength filtering and an array of IR detectors to visualize the IR absorption of hydrocarbons and other gaseous compounds and operates much like a consumer video camcorder and provides a real-time visual image of gas emissions or leaks to the atmosphere.
Applicability	The OGI system provides a technology that can potentially reduce the time, labor and cost of monitoring components.
Costs	The capital cost of purchasing an OGI system is estimated to be $85,000 to $124,000. Provides an analysis of cost of use in the field which ranged from The EPA estimated that the OGI can monitor 1,875 to 2100 components or pieces of equipment per hour and for every hour of video footage, the operator would spend an additional 1.4 hours conducting activities for calibration, OGI adjustments, tagging leaks and other activities..
Efficacy and Prevalence	Can identify hydrocarbon plumes from components and equipment only, no capability to quantify emission rate. Cost depend on site and overall approach of survey.

Approach	Acoustic Leak Detector
Description	Acoustic leak detectors are used to detect the acoustic signal that results when pressurized gas leaks from a component. Generally, two types of acoustic leak detection methods are used; high frequency acoustic leak detection and ultrasound leak detection.
Applicability	Can be used at most facilities in the sector.
Costs	No cost data for acoustic leak detectors were available in the studies or research documents.
Efficacy and Prevalence	Acoustic detectors do not measure leak rates, but do provide a relative indication of leak size measured by the intensity of the signal. A study measured leaks using the VPAC device and high volume sample to compare the readings from the two devices. No statistically significant correlation between the VPAC and the direct flow measurements. They determined that the VPAC method was not considered to be an accurate alternative to direct measurement for the sources tested.
Approach	Ambient/Mobile Monitoring
Description	A mobile measurement approach to investigate a variety of source emissions and air quality topics.
Applicability	For oil and natural gas applications, a vehicle can be equipped with at minimum a methane measurement instrument and GPS to facilitate discovery of previously unknown sources and in more advanced forms, provide information on source emission rates.
Costs	Mobile measurement instrument packages can range in cost from approximately $20,000 - $100,000 depending on the capability of the package.
Efficacy and Prevalence	Mobile leak detection techniques can cover large survey areas and can be particularly useful in identifying anomalous operating conditions (e.g., pipeline leaks and well pad malfunctions) in support of onsite OGI and safety programs. Impacted by weather conditions and line-of sight obstacles.
Approach	Repair - Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, 2013, Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants, 2002 and Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, 2006.
Description	Three studies were conducted to evaluate the cost effectiveness of leak detection and repair at natural gas processing plants and upstream compressor stations and well sites. Studies focused on gas savings as factor in economic incentive to identify and repair leaks
Applicability	Applicable for natural gas processing plants and compressor stations and well sites.
Costs	Cost of the monitoring (estimated to be $600 to $1,800 per facility, and repair, when considering economic benefits of gas savings, is less that the survey cost.
Efficacy and Prevalence	Over 95% of total natural gas losses can be reduced cost-effectively The studies had similar conclusions and that a leak is found it is almost always economic to repair it.

3.4 Peer Review Opinion

The primary peer review comments generally included that the white paper does not provide an integrated synthesis of the lessons from the cited literature sources; should provide comparisons and conclusions about the differences between all sources; the EPA has rendered no technical opinion on the underlying studies and reports; improperly defines leaks; studies referenced by the white paper appear to establish an emission rate for various types of leaking components, but these emission rates are applied based on an estimated component count, and therefore yields a “potential” emission rate and not an actual emission rate; the UT study did include components measured with zero emissions in the development of an average emission rate; however, only the components measured were included in the averaging and not the total population of components at the location, also, the “average emissions rate” is applied to each component, which presumes that every component is leaking at that average rate for the entire estimation period, yielding a potential emission value and not an actual emissions value and improperly inflates both the emissions associated with leaks as well as estimated “cost recovery;” the white paper does not address the uncertainty in the average facility-level or process unit-level component counts, or the challenges of getting accurate component counts; no indication is given regarding the accuracy of the leak-rate correlation and different emission factor methods and how the accuracy is impacted by the number of components considered (other than indicating they should not be applied to individual components); the white paper fails to recognize the AVO inspection; contend the acoustical method does not distinguish between natural gas leaks and leaks of other types of gases; the variety of equipment configurations that can be used in mobile measurement studies is not reflected the white paper; did not address area and building monitoring systems, use of odorants, soap solutions and mass balance techniques for leak detection; the URS/UT study was conducted at a compressor station and the vibrations associated with compression may influence the ability of the acoustic sensor to detect and quantify leaks and results of the study should not be generalized.

4.0 Pneumatic Devices

4.1 Pneumatic Controllers

4.1.1 Description of Process

A *pneumatic controller* is an automated instrument used to control a valve for the purpose of maintaining a process condition such as liquid level, pressure, pressure difference or temperature. Controllers may be powered by pressurized natural gas or by other sources of power, such as solar, electric and instrument air. In many situations, across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas. These natural gas-driven pneumatic controllers may be characterized by their emissions characteristics as follows:

- *Continuous bleed*, which continuously vent natural gas and have been further divided between *low bleed* (bleed or emission rate ≤ 6 standard cubic feet per hour (scfh)) and *high bleed* (bleed rate > 6 scfh).
- *Intermittent*, which emit natural gas only when actuated.
- *Zero bleed*, which are self-contained and release gas to a downstream pipeline instead of to the atmosphere.

4.1.2 Emissions Data

Source of Data	Methane Emissions from the Natural Gas Industry, 1996
Emissions Source Description	Pneumatic controllers (PCs) in the natural gas production, processing and transmission industry segments.
Type of Data:	Data on emissions and inventory of PCs at facilities in each studied segment extrapolated to estimate national methane emissions in 1992.
Estimation/ Measurement	Combination of measured emissions, manufacturers' data and site visits to estimate emission and activity factors for each industry segment
Methane or VOC emission factors/ emissions findings	Production: 125,925 scfy/PC x 249,111 PCs = 592,349 MT methane/yr Processing: 165,000 scfy/facility x 726 facilities = 2,262 MT methane/yr Transmission: 162,197 scfy/PC x 87,206 PCs = 267,093 MT methane/yr
Applicability to ONG Sector	Data specific to ONG segments that were studied
Source of Data	Estimates of Methane Emissions from the U.S. Oil Industry, 1999
Emissions Source Description	PCs at tank batteries in the oil production industry segment, characterized as high bleed and low bleed.
Type of Data:	Used bleed rates from the GRI/EPA study above and from Natural Gas STAR along with estimated inventory to estimate 1995 national methane emissions.
Estimation/ Measurement	Assumed emission rate for high bleed PCs at the "generic" rate from GRI/EPA study above; assumed default emission rate for low bleed PCs from Natural Gas STAR. Assumed 35% high bleed and 65% low bleed based on the split between continuous and intermittent PCs found in GRI/EPA.
Methane or VOC emission factors/ emissions findings	High bleed: 345 scfd, 157,581 PCs, 376,000 MT methane/yr Low bleed: 35 scfd, 292,650 PCs, 69,900 MT methane/yr

Applicability to ONG Sector	PC inventory estimated based on oil production industry segment data; PC emission rates based on rates from NG production industry segment.
Source of Data	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012,2014
Emissions Source Description	PCs in natural gas production, processing, transmission and storage segments and the petroleum production segment.
Type of Data:	National methane emissions estimated for each segment; regional "potential" emissions for NG production. Emissions factors based on EPA/GRI study.
Estimation/ Measurement	PC emission factors trace back to EPA/GRI study, with regional factors for NG methane content. Inventory of PCs in each segment based on ratios of PCs to activity counts. "Potential" emissions then corrected based on reported Natural Gas STAR reductions to get net emissions.
Methane or VOC emission factors/ emissions findings	2012 NG and oil production: 769,522 MT methane net 2012 NG processing: 1,923 MT methane (potential – no NG STAR correction) 2012 NG transmission and storage: 249,483 MT methane net
Applicability to ONG Sector	PC emission rates and inventory specific to ONG sector.
Source of Data	Greenhouse Gas Reporting Program, 2013
Emissions Source Description	PCs in three segments: onshore petroleum and NG production, onshore NG transmission compression, and underground NG storage.
Type of Data:	GHGRP requires source-specific emissions reports from all ONG facilities with GHG emissions ≥ 25,000 MT CO_2e, which is a subset of all facilities.
Estimation/ Measurement	Facilities determine the number of each type of PC and apply emission factors. Emission factors are based on a 2009 API document, which in turn is based on the GRI/EPA study.
Methane or VOC emission factors/ emissions findings	2012 Petroleum and NG production: 417 facilities; 861,224 MT methane 2012 NG transmission: 330 facilities; 7,582 MT methane 2012 NG storage: 38 facilities; 4,493 MT methane
Applicability to ONG Sector	Annual emissions data specific to ONG sector, but only from a subset of all facilities.
Source of Data	Measurements of Methane Emissions at Natural Gas Production Sites in the US, 2013
Emissions Source Description	PCs in the NG production industry segment.
Type of Data:	Measurement data for a sample of 305 pneumatic controllers located at 150 distinct natural gas production sites in four production regions (Appalachian, Gulf Coast, Midcontinent, and Rocky Mountain)
Estimation/ Measurement	NG emission rates determined using a portable instrument and converted to methane rates based on site-specific NG composition. Estimate of 2011 national methane emissions based on the number of PCs used in the GHG Inventory for 2011.
Methane or VOC emission factors/ emissions findings	2011 NG production: 570,000 MT methane (with a range of 510,000 – 812,000 MT). Found significant unexplained geographical variability in the PC emission rates between production regions (greater than a factor of 10 between highest and lowest).
Applicability to ONG Sector	Direct emissions measurements from PCs in the NG production sector. Relied on owners for type of PCs, and only low bleed and intermittent were reported.
Source of Data	Determining Bleed Rates for Pneumatic Devices in British Columbia, 2013
Emissions Source Description	High bleed PCs at upstream ONG facilities in British Columbia
Type of Data:	Measurement data from multiple units of a number of models of PCs in British Columbia. Centered on high bleed PCs, defined based on emissions including both continuous bleed (when applicable) and emissions during activations.
Estimation/ Measurement	NG emissions rates determined using a portable instrument; not converted to methane rates. No attempt to estimate national or area emissions.
Methane or VOC emission factors/ emissions findings	Developed NG emission factors for numerous models of PCs and "generic" high bleed PCs and "generic" high bleed intermittent PCs. Regression analysis used to develop coefficients relating bleed rate to supply gas pressure for some models and the generics.
Applicability to ONG Sector	Targeted only high bleed PCs. Did not differentiate between NG and oil applications.

Source of Data	Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas, 2014
Emissions Source Description	PCs associated with wet gas and dry gas wells.
Type of Data:	VOC emissions based on NG emission factors derived from information for high bleed PCs provided to Natural Gas STAR by the manufacturers.
Estimation/ Measurement	Estimated VOC emissions for the Marcellus Shale region by estimating the number of wet and dry wells in the region and establishing per-well NG emission factors for 2009. Per-well factors developed based on emissions factors and per-well PC counts from a 2008 ENVIRON report.
Methane or VOC emission factors/ emissions findings	2009 VOC emissions, tons per producing well (95% confidence interval); Dry gas: 0.5 (0.08 – 0.8); Wet gas: 3.5 (2.4 – 4.4)
Applicability to ONG Sector	Emission rates based on PC manufacturer specs, not field testing. Per-well PC count from 2008 ENVIRON report based ONG survey data.
Source of Data	Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, 2014
Emissions Source Description	PCs in the oil and NG sector.
Type of Data:	Adjusted emissions from the GHG Inventory for 2011, which is national in scope.
Estimation/ Measurement	Developed new activity and emissions factors for PCs, starting with the GHG Inventory for 2011 and using Allen et al., 2013. Emission factors for low bleed, high bleed, and two types of intermittent PCs. Added 8.6 PCs per gathering/boosting area not covered in the GHG Inventory
Methane or VOC emission factors/ emissions findings	Estimated methane emissions in 2011 were 491,000 MT higher than GHG Inventory figures.
Applicability to ONG Sector	Based on data specific to the ONG sector.

4.1.3 Mitigation Approaches

Approach	Install Zero Bleed Controller in Place of Continuous Bleed Controller, 2012
Description	Zero bleed controllers are self-contained natural gas-driven devices that vent to the downstream pipeline, not the atmosphere. Provide the same functional control as continuous bleed controllers, where applicable.
Applicability	Applicable only for relatively low-pressure control valves, e.g., in gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution applications.
Costs	The EPA does not have cost information on this technology.
Efficacy and Prevalence	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field; however, it is the EPA's understanding that applicability is limited.
Approach	Install Low Bleed Controller in Place of High Bleed Controller, 2006
Description	Low bleed controllers provide the same functional control as a high bleed devices, while emitting less continuous bleed emissions.
Applicability	Applicability depends on the function of instrumentation for an individual device and whether the device is a level, pressure, or temperature controller. Not recommended for control of very large valves that require fast and/or precise response to process changes. These are found most frequently on large compressor discharge and bypass pressure controllers.
Costs	Based on information from Natural Gas STAR and supplemental research conducted for subpart OOOO, low bleed devices cost, on average, around $165 more than high bleed versions. ICF report assumed a cost of $3,000 per replacement based on industry comments.
Efficacy and Prevalence	Estimated average reductions: Production segment: 6.6 tpy methane; *Transmission:* 3.7 tpy methane. The EPA does not have information on the prevalence of this technology in the field.
Approach	Convert to Instrument Air, 2006
Description	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. 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.
Applicability	Most applicable at facilities where there are a high concentration of pneumatic control valves and an operator present. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device.
Costs	System costs are dependent on size of compressor, power supply needs, labor and other equipment. A cost analysis is provided in Section 3.1.3 of the white paper.
Efficacy and Prevalence	100% emission reduction, where applicable. There are secondary emissions associated with electrical power generation. The EPA does not have information on the prevalence of this technology in the field.
Approach	Mechanical and Solar-Powered Systems in Place of Bleed Controller
Description	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 backup power or storage to ensure reliable operation.
Applicability	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.
Costs	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Efficacy and Prevalence	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field.
Approach	Enhanced Maintenance, 2006
Description	Instrumentation in poor condition typically bleeds 5 to 10 scfh more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear; or loose control tube fittings. This may not impact operations but does increase emissions. Proper methods of maintaining a device are highly variable.
Applicability	Enhanced maintenance to repair and maintain pneumatic controllers periodically can reduce emissions at many controllers.
Costs	Variable based on labor, time, and fuel required to travel to many remote locations.
Efficacy and Prevalence	Natural gas emission reductions of 5 to 10 scfh. The EPA does not have information on the prevalence of this practice in the field.

4.2 Pneumatic Pumps

4.2.1 Description of Process

Two types of pneumatic pumps are commonly used in the oil and natural gas sector: piston and diaphragm. The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation. Chemical injection pumps inject small amounts of chemicals to limit processing problems and protect equipment. “Kimray” pumps used for glycol circulation 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.

4.2.2 Emissions Data

Source of Data	Methane Emissions from the Natural Gas Industry, 1996
Emissions Source Description	Chemical injection (CI) pumps (piston and diaphragm) Glycol pumps.
Type of Data:	Data on emissions and inventory of CI pumps in NG production segment and glycol pumps in NG production and processing segments, extrapolated to estimate national methane emissions in 1992.
Estimation/ Measurement	CI pumps: Manufacturer data and limited measurements for emission rate; site visits for inventory and duty cycle of piston and diaphragm pumps. Glycol pumps: Manufacturer

	data for emission rate; activity is NG throughput.
Methane or VOC emission factors/ emissions findings	CI pumps: 248 scfd/pump x 16,971 pumps = 29,008 MT methane. Glycol pumps, NG production: 206,989 MT methane. Glycol pumps, NG processing: 3,215 MT methane
Applicability to ONG Sector	Directly applicable to ONG sector; very limited emission measurement data; limited site visit data.
Source of Data	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, 2014
Emissions Source Description	CI pumps in NG and Petroleum production segments; glycol pumps in the NG production and processing segments.
Type of Data:	National methane emissions estimated for each segment; regional "potential" emissions for NG production. Emission factors based on EPA/GRI study.
Estimation/ Measurement	Pump emission factors trace back to EPA/GRI study, with regional factors for NG methane content. Inventory of CI pumps in each segment based on ratios of PCs to activity counts. "Potential" CI pump emissions for NG production then corrected based on reported Natural Gas STAR reductions to get net emissions. Glycol pump activity is estimated NG throughput by region. No correction to potential emission for glycol pumps or CI pumps for petroleum.
Methane or VOC emission factors/ emissions findings	2012 CI pumps in NG production: 64,570 MT methane net 2012 CI pumps in Petroleum production: 49,973 MT methane potential 2012 Glycol pumps in NG production and processing: 388,378 MT potential
Applicability to ONG Sector	Pump emission rates and activity levels specific to ONG sector; emissions rates based on 1996 GRI/EPA report.
Source of Data	Greenhouse Gas Reporting Program, 2013
Emissions Source Description	Pumps at onshore petroleum and NG production facilities.
Type of Data:	GHGRP requires source-specific emissions reports from all ONG facilities with GHG emissions ≥ 25,000 MT CO_2e, which is a subset of all facilities.
Estimation/ Measurement	Facilities determine the number pumps and apply an emission factor of 13.3 scfh NG and a facility-specific NG composition factor to calculate methane
Methane or VOC emission factors/ emissions findings	2012 Pumps in onshore ONG production: 343 facilities; 135,227 MT methane.
Applicability to ONG Sector	Annual emissions data specific to ONG sector, but only from a subset of all facilities.
Source of Data	Determining Bleed Rates for Pneumatic Devices in British Columbia, 2013
Emissions Source Description	CI pumps at upstream ONG facilities in British Columbia.
Type of Data:	Measurement data from 184 CI pumps.
Estimation/ Measurement	NG emissions rates determined using a portable instrument; not converted to methane rates. No attempt to estimate national or area emissions.
Methane or VOC emission factors/ emissions findings	NG emission factor for piston CI pumps: 0.5917 m^3/hr (~ 20.9 scfh) NG emission factor for diaphragm CI pumps: 1.0542 m^3/hr (~37.2 scfh)
Applicability to ONG Sector	Did not differentiate between NG and oil applications.
Source of Data	Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, 2014
Emissions Source Description	CI and glycol pumps in NG production segment.
Type of Data:	Adjusted emissions from the GHG Inventory for 2011, which is national in scope
Estimation/ Measurement	Used data from the GHG Inventory for 2011 and the GHGRP, as well as EIA and GRI. For CI pumps, updated the count to reflect changes made to the well counts and applied the Natural Gas STAR estimated reductions.
Methane or VOC emission factors/ emissions findings	2011 CI pumps in NG production: 56,600 MT 2011 Glycol pumps in NG production: 321,000 MT
Applicability to ONG Sector	Based on data specific to the ONG sector.

4.2.3 Mitigation Approaches

Approach	Replace natural gas-assisted pump with instrument air pump, 2011)
Description	Circulation pumps in glycol dehydration units and chemical injection pumps are retrofitted with instrument air to drive the pumps.
Applicability	Facilities with excess capacity of instrument air or facilities that can install an air compressor system. Because the systems are powered by electric compressors, they require a constant source of

	electrical power or a backup natural gas pneumatic pump.
Costs	The installation of the piping from the air compressor system to the pump accounts for the bulk of the capital cost and typically ranges from $100 to $1,000.
Efficacy and Prevalence	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 2,500 Mcf for glycol circulation pumps and 183 Mcf for chemical injection pumps. The EPA does not have information on the prevalence of this technology in the field.
Approach	Replace natural gas-assisted pump with solar-charged direct current pump, 2011
Description	In field settings, low volume natural gas pneumatic pumps can be replaced with solar-charged DC pumps.
Applicability	Low volume solar-charged pneumatic pumps are limited to approximately 5 gallons per day discharge at 1,000 psig. Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig.
Costs	The reporting partners for Natural Gas STAR stated a replacement cost of $2,000 per pump, including the solar panels, storage batteries and pump.
Efficacy and Prevalence	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 182.5 Mcf per chemical injection pump conversion. The EPA does not have information on the prevalence of this technology in the field.
Approach	Replace natural gas-assisted pump with electric pump, 2014
Description	In settings where a constant supply of electricity is available, natural gas pneumatic pumps can be replaced with electric pumps.
Applicability	These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity.
Costs	Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year.
Efficacy and Prevalence	100% emission reduction, where applicable. The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf. The EPA does not have information on the prevalence of this technology in the field.

4.3 Peer Review Opinion

Pier review commenters stated the white paper summarizes the data available at the time the white paper was written, with one exception – the data on pneumatic pumps reported in Allen et al. (2013). Allen, et al. (2013) reports statistically higher emissions for the 21 pumps on which emission measurements were made in the Gulf Coast region (0.506±0.209 scf whole gas per pump per hour), compared to the 41 pumps on which emission measurements were made in the Midcontinent region (0.050±0.014 scf whole gas per pump per hour). Allen, et al. (2013) was not able to determine, from the data collected, the reasons for the regional differences in emissions, which was not reflected in the emission factors from the GHG Inventory for 2012 presented in Table 2-14 of the white paper.

5.0 Compressors

5.1 Description of Process:

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. Vented emissions from compressors occur from seals (wet seal compressors) or packing surrounding the mechanical compression components (reciprocating compressors) of the compressor. In the production segment, compressors are used at the wellhead to compress gas for fluids removal, and pressure equalization with gathering equipment systems. However, the primary use of compressors is in the natural gas processing, transmission and storage (particularly underground storage) segments of the industry. In the oil and natural gas sector, the most prevalent types of compressors used are reciprocating and centrifugal 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. Over the operating life of the compressor, the rings become worn and the packing system will begin to wear, resulting in higher leak rates. Emissions from packing systems originate from mainly four components: the nose gasket, between the packing cups, around the rings and between the rings and the shaft. Typically, gases leaked from the packing system are vented to the atmosphere.

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 and are widely used in the processing and transmission industry segments. Centrifugal compressors are equipped with either a wet or dry seal configuration. Wet seals use oil around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The oil is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process (degassing or off- gassing). Alternatively, dry seal compressors use the opposing force created by hydrodynamic grooves and springs to provide a seal. 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. Gas emissions from wet seal centrifugal compressors have been found to be higher than dry seals compressors primarily due to the off-gassing of the entrained gas from the oil. The maintenance costs less than wet seal compressors because they are a mechanically simpler design, require less power, are more reliable and require less maintenance.

5.2 Emissions Data

Source of Data	GRI/EPA Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, 1996
Emissions Source Description	Reciprocating and centrifugal compressor seals from the natural gas production, processing, transmission and storage sector.
Type of Data:	Estimate of annual methane emissions from using the component method.
Emissions Estimation/ Measurement	Component method, average emission factors for reciprocating and centrifugal compressor seals and the average number of reciprocating and centrifugal compressors per facility to estimate the average facility emissions; emission factors based on screening of components using OVA and TVA.
Methane or VOC emission factors/ emissions findings	Production: 40 reciprocating compressor seals; emission factor 2.37 Mcfy per cylinder. Processing, Transmission and Storage: Both types of compressors, pressurized and non-pressurized operation modes; 599 Mcfy per seal pressurized and 116 Mcfy per seal in idle. Emission factors developed using time compressor is pressurized, number of seals.
Applicability to ONG Sector	Presented the emissions for reciprocating and centrifugal compressors as a sum of the emission components from compressors. These components included methane emissions from compressor seals, blowdown open-ended line, pressure relief valves, starter open-ended line, and miscellaneous, which includes valves and connectors. Compressor emissions were calculated in tpy using component count per compressor. White paper summarized average methane emission from each segment in MT per year using GRI data.
Source of Data	Natural Gas Industry Methane Emission Factor Improvement Study, Final Report, 2011
Emissions Source Description	Focused on processes and equipment believed to contribute the greatest uncertainty to the emissions inventory; fugitive leaks from transmission, gathering/boosting and processing compressor components including vents.
Type of Data:	Implications for usefulness: quality, quantity, national, source-specific, geographic distribution.
Emissions Estimation/ Measurement	Measured using anemometer.
Methane or VOC emission factors/	Gathering and boosting reciprocating compressor; 15 sampled, 241 mscf/yr methane emissions. Transmission reciprocating compressor; 5 sampled idle, 12,236 Mscf/yr

emissions findings	methane and 2 sampled pressurized, 29,602 Mscf/yr methane. All centrifugal compressors; wet seal 9 sampled 8,137 Mscf/yr methane.
Applicability to ONG Sector	Study concluded wet seal centrifugal compressor and reciprocating compressor emissions were much higher than GRI/EPA factor. Noted that data should only be a benchmark, and not used to develop emission factors due to technical issues with measuring emissions from compressors.
Source of Data	Greenhouse Gas Reporting Program, 2013
Emissions Source Description	Reciprocating and centrifugal compressors in the processing, transmission and underground storage segments and liquid natural gas import/export and storage segments.
Type of Data:	Reported by facility, not compressor-specific, total methane emissions by compressor type, number of compressors.
Emission Estimation/ Measurement	Prescribed in subpart W, direct measurement or engineering calculations.
Methane or VOC emission factors/ emissions findings	Presented total number of reciprocating compressors and centrifugal compressors (with wet seal and without), total methane emissions for processing transmissions and storage segments.
Applicability to ONG Sector	Reporting threshold limits data reported; useful for overall sector characterization, not emission factor development.
Source of Data	Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, 2014
Emissions Source Description	Reciprocating compressors in production through distribution.
Type of Data:	Calculated methane emissions for large and small reciprocating compressor, wet and dry seal centrifugal compressors in production, processing, transmission, storage segments.
Emissions Estimation/ Measurement	Uses GRI/EPA emission factors developed in 1996 study.
Methane or VOC emission factors/ emissions findings	Inventory reports nationwide 2012 based on 2012 activity and factors current emissions.
Applicability to ONG Sector	Valuable for recent activity data and overall characterization of segments. No new emission factor information.
Source of Data	Development of the New Source Performance Standard (NSPS) For Oil and Natural Gas Production, 2012.
Emissions Source Description	Reciprocating and centrifugal compressors in the natural gas sector.
Type of Data:	Used the emission factors from the GRI/EPA study and gas composition data developed for the NSPS subpart OOOO and methane density of 41.63 pound per Mcf.
Emissions Estimation/ Measurement	Calculated VOC emission rates using emission factors, gas composition methane to pollutant rations.
Methane or VOC emission factors/ emissions findings	Developed emission factors in tons/compressor/year for methane and VOC for reciprocating compressors and wet and dry-seal centrifugal compressors for all segments in the sector.
Applicability to ONG Sector	Used in the proposed Subpart OOOO.
Source of Data	Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses, 2012
Emissions Source Description	Centrifugal compressors, specifically on prevalence of wet and dry seal compressors.
Type of Data:	Compressor counts comparison to EPA 2012 GHG Inventory.
Emissions Estimation/ Measurement	Survey of 20 companies for specific information on number of wet seal and dry seal compressors in processing segment and 81 percent of compressors in production were dry seal.
Methane or VOC emission factors/	No emissions factors. Survey results indicate that 79 percent were dry seal and 21 percent were wet seal compressors.

emissions findings	
Applicability to ONG Sector	Small portion of total compressor population was included in survey results (5 percent).
Source of Data	Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, 2014
Emissions Source Description	Targeted 22 methane emissions sources in the industry which including centrifugal and reciprocating compressors.
Type of Data:	Study used emissions baseline from previous ICF 2011 which updated 2013 GHG inventory numbers to project emissions to 2018.
Emissions Estimation/ Measurement	Different methods were used for each segment to project emissions to 2018 based on baseline.
Methane or VOC emission factors/ emissions findings	Emissions for 2018 were calculated and adjusted to account for effects of NSPS (subpart OOOO).
Applicability to ONG Sector	Based on prior studies and included no new emissions factors or emissions data.

5.3 Mitigation Approaches

Approach	Reciprocating Compressor - Rod Packing Replacement
Description	Replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod due to deterioration and wear.
Applicability	Applicable or all reciprocating compressor used in the sector and is currently an industry practice.
Costs	On average replacement is conducted every 4 years at a cost of $1620 per cylinder. Capital cost per compressor in production $6,480 with gas savings for life of compressor of $2,493. For gathering and boosting capital cost of $5,346 with gas savings of $1,669; for processing capital cost of $4,040 with gas savings of $1,413; for transmission capital cost of $5,346 with gas savings of $1,669, and for storage capital cost of $7,290 with gas savings of $2,276.
Efficacy and Prevalence	Per compressor methane emission reductions; Production 0.158 tpy, gathering and boosting 6.84 tpy, processing 18.6 tpy, transmission 21.7 tpy and storage 21.8 tpy. VOC emission reductions: production 0.04 tpy, gathering and boosting 1.9 tpy, processing 5.18 tpy, transmission 0.6 tpy, and storage 0.6 tpy. Prevalent practice in the industry.
Approach	Reciprocating Compressor – Gas Recovery
Description	Capture gas emissions from reciprocating compressor and route the gas back to the engine as fuel or capture and route to a vapor recovery unit. Gas saved can be used as fuel or flared.
Applicability	Generally applicable across the sector, particularly for processing plants due to availability of processes to use gas.
Costs	Cost data not available for a gas recovery system that routes back to the engine as a fuel. Estimated cost of additional piping to route to VRU is $2,000 assuming VRU onsite.
Efficacy and Prevalence	99% reduction of emissions of gas recovered and used as a fuel for process or a VRU. 95% reduction if emissions are captured and flared.
Approach	Centrifugal Compressor - Dry Seals
Description	Replace wet-seal compressor with dry-seal compressor. Results in emissions reductions, higher reliability, and overall maintenance and operating costs.
Applicability	Applicable for most centrifugal compressors, however, not all. Due to size and certain applications, certain wet-seal compressors cannot be replaced with dry seal compressors.
Costs	For processing, transmission and storage, capital cost of $75,000 and annual operation and maintenance savings of $88,300. Processing also realizes a natural gas savings of $46,109.
Efficacy and Prevalence	Methane emissions reductions per compressor is 199 tpy for processing, 110 tpy for transmission and storage. VOC reduction per compressor 18 tpy for processing and 3 tpy for transmission and storage.
Approach	Centrifugal Compressor - Wet Seal with a Flare
Description	Capture emissions and route to a flare.

Applicability	Generally applicable for all segments.
Costs	For processing, transmission and storage segments, an enclosed flare capital cost is $67,918 with annual cost of $98,329.
Efficacy and Prevalence	95% emissions reduction. Not prevalent in the industry.
Approach	Centrifugal Compressor - Wet Seal with gas recovery for use onsite
Description	Capture emissions and route to some process operation.
Applicability	Generally applicable for all segments.
Costs	For processing, transmission and storage segments, an enclosed flare capital cost is $22,000. For the processing segment there is an estimated annual gas savings of $44,729 and $24,849 for the transmission and storage segments.
Efficacy and Prevalence	95% emissions reduction. Not prevalent in the industry.

6.0 Liquids Unloading

6.1 Description of Process:

In most gas wells, at some point in the productive life of the well, as the reservoir pressure declines during production, there is a point when the pressure is not sufficient to facilitate the flow of accumulated water and hydrocarbon liquids to the surface along with produced gas. When this occurs, this accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required in order to maintain production. Emissions to the atmosphere during liquids unloading events are a potentially significant source of VOC and methane emissions.

To restore the pressure, the operator intentionally manually vents the well to the atmosphere to improve gas flow. Additionally, a plunger lift system can be used which uses the well's own energy (gas/pressure) to lift liquids from the tubing by pushing the liquids to the surface by the movement of a free-traveling plunger ascending from the bottom of the well to the surface. The plunger essentially acts as a piston between liquid and gas allowing the operator more control of the liquids removal process.

6.2 Emissions Data

Source of Data	Greenhouse Gas Reporting Program, 2013
Emissions Source Description	Reporting threshold (i.e., only facilities emitting 25,000 metric tons or more of CO_2e; wells that are venting, with and without plunger lift operation; annual reporting.
Type of Data:	Nationwide, limited by reporting threshold, facilities report methane emissions and number of venting wells, whether or not equipped with plunger lift.
Emissions Estimation/ Measurement	Subpart W provided defines 3 methods, direct measurement and two engineering calculations; one with plunger lift one without.
Emission factors/ emissions findings	Data only at facility level, not well specific. 251 facilities reporting, total number of wells venting 58,5663, number of venting wells with plunger lifts 32,252, total methane emissions 276,378 MT.
Applicability to ONG Sector	Generally comprehensive with exception that the limited due to reporting threshold and reporting requirements and methods. Facility reporting level, not well-specific.
Source of Data	Inventory of Greenhouse Gas , Emissions and Sinks: 1990-2012 (published 2013)
Emissions Source Description	Natural gas production through distribution and petroleum production through refining.
Type of Data:	Reported data on wells conducting liquids unloading, with and without plunger lifts, activity data, total emissions, updated by API/ANGA survey data.
Emissions Estimation/ Measurement	Uses the NEMS emission factors to percentage of wells requiring liquids unloading based on the API/ANGA survey data (see Data Source below).
Methane or VOC emission factors/ emissions findings	Provided emission factors for scfy/well, number of wells, by 6 NEMS regions of US; inventory estimates of liquids unloading emissions were 14 percent of overall methane emissions from natural gas production segment.

Applicability to ONG Sector	Similar to API/ANGA data, however, applied region specific notations, possibly correlating more to geographic and basin applicability.
Source of Data	Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses 2012
Emissions Source Description	20 companies covering 90,000 gas wells, including gas wells that conduct liquids unloading.
Type of Data:	Well-level data methane emissions.
Emissions Estimation/ Measurement	Used 40 CFR part 98, subpart W engineering equations to estimate emissions using well-specific data on well bore volume, well pressure, venting time and gas production rate.
Methane or VOC emission factors/ emissions findings	Calculated number of wells vented with and without plunger lifts, 322,854 scfy gas vented per well, 254,409 scfy methane per well; authors found that EPA emission estimates were highly overestimated; most of the emission were produced by less than 10 percent of the well population.
Applicability to ONG Sector	Provided well-specific data on wells that conduct liquids unloading, vent and not vent, with and without plunger lifts, most comprehensive data available to date on liquids unloading.
Source of Data	Measurements of Methane Emissions at Natural Gas Production Sites in the United States, 2013
Emissions Source Description	Academic study, onshore natural gas wells sites in US, compared measured emission rates to 2011 GHG emission inventory estimates.
Type of Data:	Length of unloading events, continuous and intermittent flow events.
Emissions Estimation/ Measurement	Direct measurement by sampling and analysis at nine well unloading events.
Methane or VOC emission factors/ emissions findings	Average emission 1.1 MT of methane per unloading event; supported API/ANGA survey findings.
Applicability to ONG Sector	Limited applicability due to small sample size.
Source of Data	Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014
Emissions Source Description	Study of economic analysis of methane emissions reduction opportunities; 22 different emission sources in industry, including liquids unloading.
Type of Data:	Used data from 2013 GHG inventory and UT Allen study.
Emissions Estimation/ Measurement	Updated emissions baseline to calculate emission factors for methane.
Methane or VOC emission factors/ emissions findings	277,000 scf/event wells with plunger lifts, 163,000 scf/venting well without plunger lifts; control costs for plunger lists and estimates for potential VOC emissions reductions from plunger lifts.
Applicability to ONG Sector	Study support use of plunger lifts as a mitigation method for emission from liquids unloading.

6.3 Mitigation Approaches

Approach	Plunger Lift Systems
Description	Plunger lifts use the well's own energy (gas/pressure) to drive a piston or plunger that travels the length of the tubing in order to push accumulated liquids in the tubing to the surface.
Applicability	Plunger systems have been known to reduce emissions from venting and increase well production. Specific criteria regarding well pressure and liquid to gas ratio can affect applicability. Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system.
Costs	Capital, installation and startup cost estimates: \$1,900-\$7,800 (Note: Commenters on the ICF study cited a cost of \$15,000. The study escalated the cost to \$20,000 .Smart automation system: \$4,700/well-\$18,000/well depending on the complexity of the system. Additional startup costs (*e.g.*, well depth survey, miscellaneous well clean out operations): \$700-\$2,600.

Efficacy and Prevalence	API/ANGA Survey data show plunger lifts can result in zero emissions or significant emissions depending on how they are operated. The EPA has learned plunger lift systems rely on manual, onsite adjustments. When a lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. Optimized plunger lift systems (e.g., with smart well automation) can decrease the amount of gas vented by up to 90+% and reduce the need for venting due to overloading.
Approach	Artificial Lift Systems (including rod pumps, beam lift pumps, pumpjacks)
Description	Artificial lifts require an external power source to operate a pump that removes the liquid buildup from the well tubing.
Applicability	The devices are typically used during the eventual decline in the gas reservoir shut-in pressure, when there is inadequate pressure to use a plunger lift. At this point, the only means of liquids unloading to keep gas flowing is downhole pump technology.
Costs	Capital and installation costs (includes location preparation, well clean out, artificial lift equipment and pumping unit): $41,000-$62,000/well. Average cost of pumping unit: $17,000-$27,000.
Efficacy and Prevalence	Artificial lifts can be operated in a manner that produces no emissions. The EPA does not have information on the prevalence of this technology in the field.
Approach	Velocity Tubing
Description	Velocity tubing is smaller diameter production tubing and reduces the cross-sectional area of flow, increasing the flow velocity and achieving liquid removal without blowing emissions to the atmosphere. Generally, a gas flow velocity of 1,000 fpm is necessary to remove wellbore liquids.
Applicability	Velocity tubing strings are appropriate for low volume natural gas wells upon initial completion or near the end of their productive lives with relatively small liquid production and higher reservoir pressure. Candidate wells include marginal gas wells producing less than 60 Mcfd. Coil tubing can also be used in wells with lower velocity gas production.
Costs	Requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well. Capital and installation costs provided from industry include: $7,000-$64,000/well.
Efficacy and Prevalence	Considered to be a “no emissions” solution. Low maintenance, effective for low volumes lifted. Often deployed in combination with foaming agents. Seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream. The EPA does not have information on the prevalence of this technology in the field.
Approach	Foaming Agents
Description	A foaming agent (soap, surfactants) is injected in the casing/tubing annulus by a chemical pump on a timer basis. The gas bubbling through the soap-water solution creates gas-water foam which is more easily lifted to the surface for water removal.
Applicability	Application of mechanical controls is limited because the control must be located A means of power will be required to run the surface injection pump. The soap supply will also need to be monitored. If the well is still unable to unload fluid, additional, smaller tubing may be needed to help lift the fluids. Foaming agents work best if the fluid in the well is at least 50% water. Surfactants are not effective for natural gas liquids or liquid hydrocarbons. Foaming agents and velocity tubing may be more effective when used in combination.
Costs	Foaming agents are low cost. No equipment is required in shallow wells. In deep wells, a surfactant injection system requires the installation of surface equipment and regular monitoring. Pump can be powered by solar or AC power or actuated by movement of another piece of equipment. Capital and startup costs to install soap launchers: $500-$3,880. Capital and startup costs to install soap launchers and velocity tubing: $7,500-$67,880 Monthly cost of foaming agent: $500/well or $6,000/yr.
Efficacy and Prevalence	Considered to be a “no emissions” solution. Low volume method applied early in production decline when bottom-hole pressure still generates sufficient velocity to lift liquid droplets. The EPA does not have information on the prevalence of this technology in the field.

6.4 Peer Review Opinion

The primary peer review comments included: the white paper was not the complete, high quality technical resource document contemplated and is not suitable to inform deliberations; some summaries are incomplete, there are misstatements and misunderstandings scattered throughout the paper; the paper does not discuss the limitations of the underlying sources of information and no critical analysis of the accuracy or validity of the sources; the paper does not provide analysis of data, only a summary; the peer reviewer states that EPA has a fundamental misunderstanding of the process of venting to assist in liquids unloading, which causes emissions as well as options for emissions mitigation; the EPA has a misconception about plunger lifts. Installation or use of plunger lifts are a technique in the management of unloading of liquids from wells, however, use of PLs does not mean "venting" will be eliminated or reduced; the white paper was erroneous on interpretation of NGS limited data that plunger lifts are an emissions mitigation technique and API/ANGA does not support it; most of the emission factors taken from the summarized studies combine wells with and without plunger lifts. Separate factors should be developed; an average emission factor based solely on venting wells does not accurately characterize the effectiveness of this control technology for eliminating emissions from the majority of wells; and since the GHGRP only includes emissions from facilities above the 25,000 MT CO_2e reporting threshold, it should not be considered a comprehensive estimate of national emissions. The 2014 GHG Inventory estimate is lower than the total emissions reported to the GHGRP, so it also clearly underestimates national emissions.

Small Business Advocacy Review Panel
Panel Outreach Meeting with Small Entity Representatives
Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

Thursday June 18, 2015
EPA HQ, WJC North, room 4530
2:00 pm – 5:00 pm (eastern)

2:00 **Welcome** (EPA's Small Business Advocacy Chair, Office of Policy (OP))

2:05 **Introduction of Panel Members/Staff**

- EPA/Office of Air (OAR)
- SBA/Office of Advocacy
- OMB/Office of Information and Regulatory Affairs (OIRA)

2:10 **Introduction of SERs and Other Attendees** (OP)

2:20 **Panel Process Questions?** (OP takes questions from SERs)

2:30 **Panel Presentation** (OAR)

3:00 **Discussion of the Rulemaking** (SERs with Panel)

- General Questions
- Hydraulically Fractured Oil Well Completions
- Fugitive Emissions
- Pneumatic Pumps
- Pneumatic Controllers
- Compressors
- Liquids Unloading
- Reporting & Recordkeeping
- Additional Input

4:50 **Next Steps and Closing** (EPA/OP)

- Comments due June 29, 2015

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Teleconference dial-in number: (866) 299-3188
Conference code: 202 564 1550
Dial the toll-free teleconference number listed above. At the prompt, enter the conference code followed by the pound [#] sign. Note: You will hear music until the leader dials into the call.

A Refresher on the Small Business Advocacy Review Panel Process

Alexander Cristofaro, Small Business Advocacy Review Chair (SBAC)

Panel Outreach Meeting, June 18, 2015

Office of the Administrator
Office of Policy
Office of Regulatory Policy and Management
http://www.epa.gov/op/orpm.html

Today's Topics

- What is a Small Business Advocacy Review (SBAR) Panel?
- Your role as a Small Entity Representative (SER)
- The difference between an SBAR Panel and a proposed regulation

What is an SBAR Panel?

- A Panel consists of representatives from the:
  - Agency authoring the regulation (i.e., EPA)
  - OMB's Office of Information and Regulatory Affairs (OIRA)
  - SBA's Office of Advocacy
- The Regulatory Flexibility Act (RFA) instructs the Panel to:
  - Review "any material the agency has prepared" related to the development of the regulation
  - Collect advice and recommendations from SERs
  - Prepare a report within 60 days of the Panel convening

See Title 5, section 609(b)(3)-(5), of the *United States Code* (USC). This is also known as section 609(b)(3)-(5) of the Regulatory Flexibility Act (RFA).

What is an SBAR Panel? (cont'd.)

- The types of materials the Panel will review and on which you, the SERs, will provide advice and recommendations are specified by law
- Section 609(b)(4) of the RFA states that "the panel shall review any material the agency has prepared…on issues related to":
  - "a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply" (Sec. 603(b)(3))
  - "a description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record" (Sec. 603(b)(4))
  - "an identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the proposed rule" (Sec. 603(b)(5))
  - "a description of any significant alternatives to the proposed rule which accomplish the stated objective of applicable statutes and which minimize any significant economic impact …on small entities" (Sec. 603(c))

Your role as a SER

- EPA values this SBAR Panel process because it provides us with important small entity perspectives and information
- Your verbal and written input is considered and valued by the Panel as the Panel develops the Panel report
- Copies of your written comments will be appended to the Panel Report and a chapter in the Panel report will summarize them.
- The Panel will consider the comments you provide to us, but the findings that ultimately appear in the report are those of the Panel members: EPA, OMB, and SBA
- The Administrator will carefully consider the input we gather from the SERs and the Panel members, but is not legally bound to adopt the recommendations of the Panel

The difference between an SBAR Panel and a proposed regulation

- SBAR Panel
  - Reviews materials related to:
    - the impacts of the regulation on small entities
    - Federal rules which may intersect with this proposed regulation
    - Alternatives to the regulation that may minimize small entity impacts
  - EPA uses the Panel report to inform our decision-making about the forthcoming proposed regulation
- Proposed regulation
  - Fully formed regulatory proposal or set of regulatory alternatives
  - You will have an opportunity to comment on the proposal, just like any other public citizen

Thank You

- Participation is voluntary and we appreciate the time and energy you put towards this rulemaking.
- Thank you - we know it is, and has been, an intense resource commitment.
- Contact my staff:
  - Nicole Owens
    EPA Office of Policy
    owens.nicole@epa.gov

Panel Outreach Briefing: Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

June 2015

Overview

- White House Announcement
- Oil and Gas Sector Description
- Coverage Under the 2012 NSPS
- Hydraulically Fractured Oil Well Completions
- Fugitive Emissions
- Pneumatic Pumps
- Pneumatic Controllers
- Compressors
- Liquids Unloading
- Reporting & Recordkeeping
- Number of Potentially Affected Sources
- Emissions Reductions from Potential Control Options
- Next Steps

Oil and Gas Sector Description

Oil Production

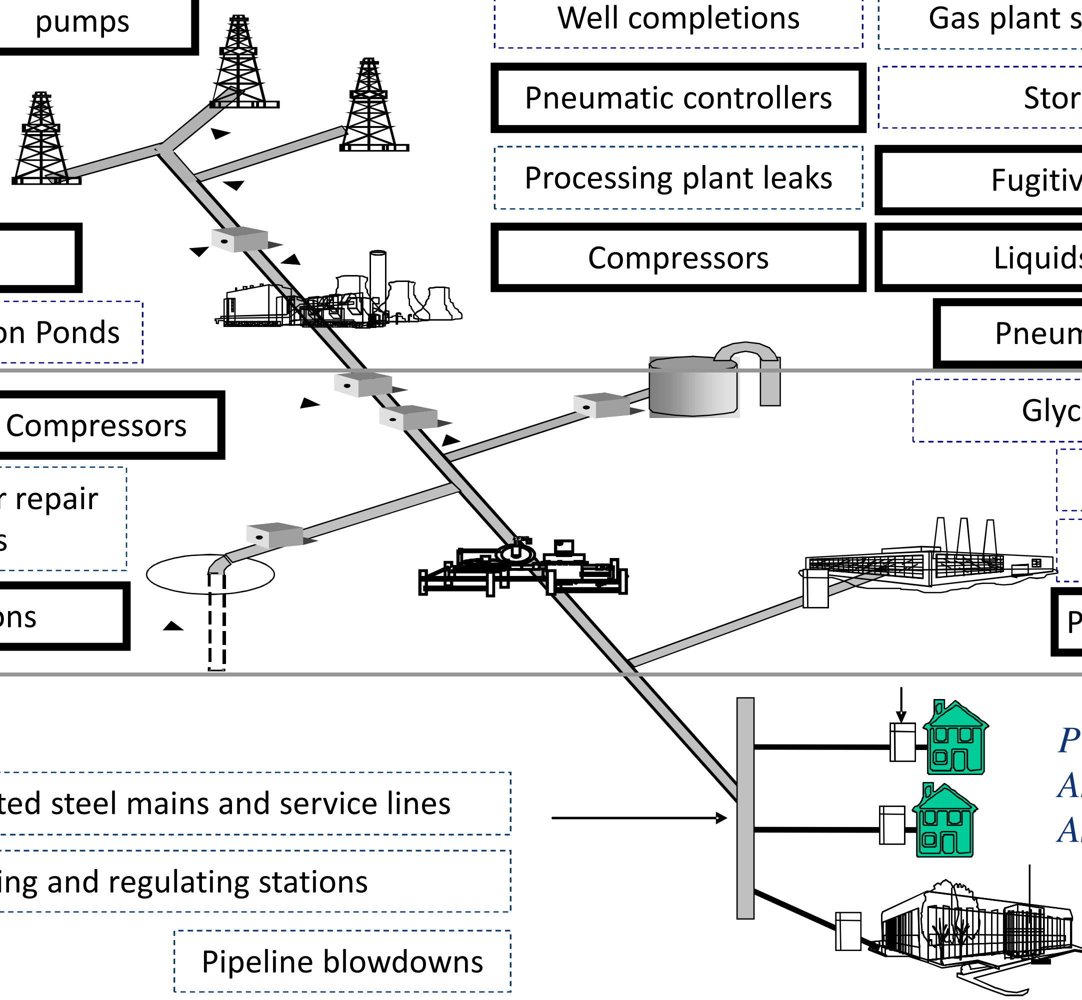
- Storage tanks
- Pneumatic pumps
- Pneumatic controllers
- Well completions
- Fugitive Emissions
- Produced Water Evaporation Ponds

Natural Gas Production & Processing

- Well completions
- Gas plant sweetening units
- Pneumatic controllers
- Storage tanks
- Processing plant leaks
- Fugitive Emissions
- Compressors
- Liquids Unloading
- Pneumatic pumps
- Glycol dehydrators

Gas Transmission

- Compressors
- Venting of gas for maintenance or repair of pipelines or compressors
- Leaks from compressor stations
- Storage tanks
- Glycol dehydrators
- Pneumatic Controllers



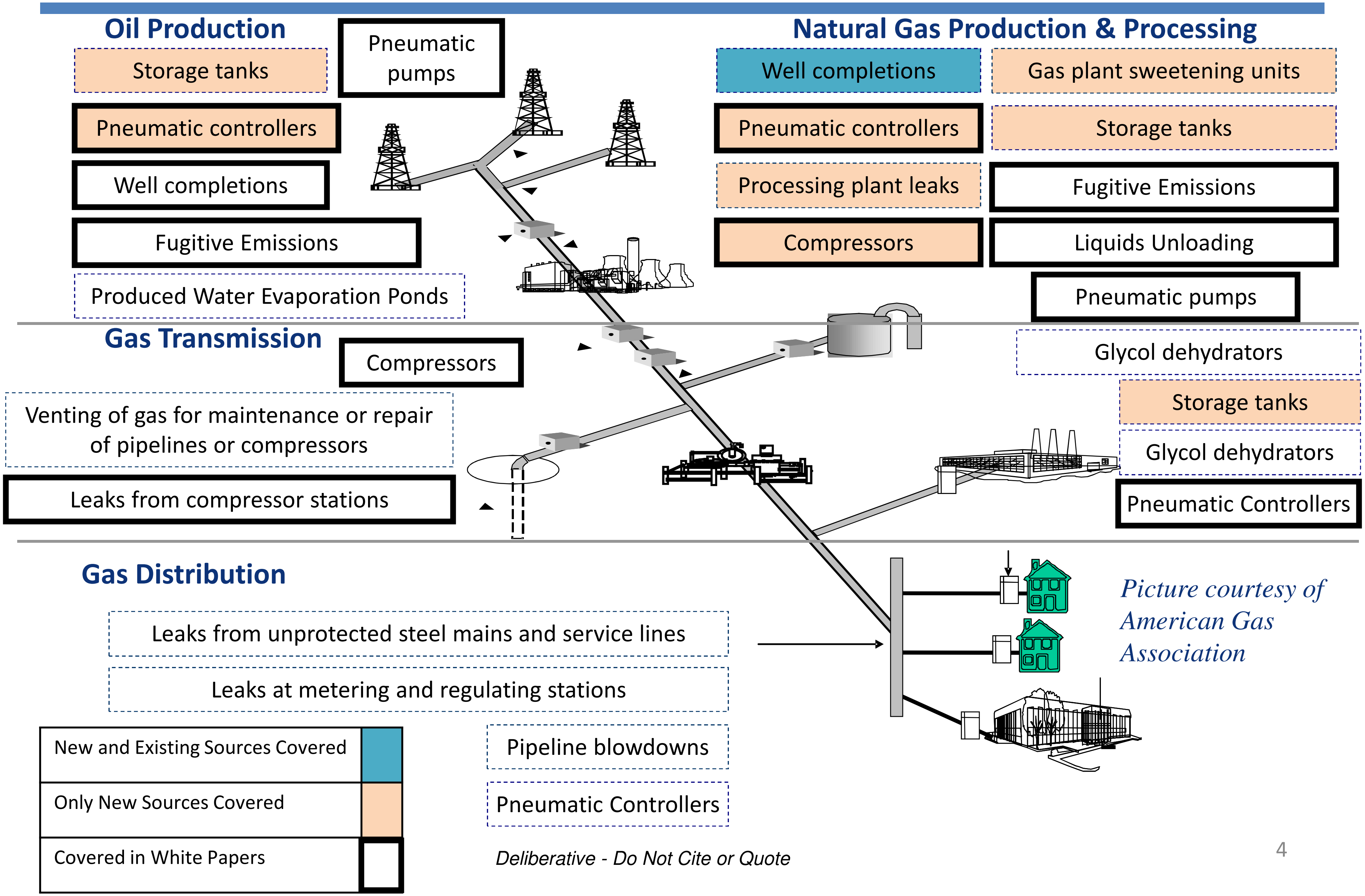
Picture courtesy of American Gas Association

Gas Distribution

- Leaks from unprotected steel mains and service lines
- Leaks at metering and regulating stations
- Pipeline blowdowns
- Pneumatic Controllers

Covered in Oil and Gas White Papers

Oil and Gas Sector – Current Regulatory Coverage



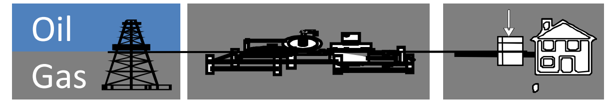
White House Announcement

- On January 14, 2015, the White House announced its path forward on oil and gas; including:
  - Regulatory approaches (NSPS)
  - Guidance to the States (CTG)
  - Voluntary programs (Expanded Natural Gas STAR)
- NSPS Improvements
  - Reduce emissions of GHGs and VOCs, and add equipment and processes to those source types currently covered by NSPS standards – note: the controls for GHG and VOC emission reductions are the same.
  - Specifically look at sources from the Oil and Gas White Papers
    - Hydraulically Fractured Oil Well Completions,
    - Fugitive Emissions,
    - Pneumatic Devices,
    - Compressors, and
    - Liquids Unloading.

Coverage of white paper sources under 2012 NSPS

- Well Completions (hydraulically fractured gas wells)
- Equipment Leaks (at natural gas processing plants)
- Pneumatic Controllers (through gas processing)
- Compressors (through gas processing, excluding well site compressors)
- Liquids Unloading (not addressed in 2012 NSPS)

Hydraulically Fractured Oil Well Completions



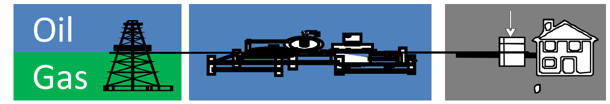
White Paper Source
2012 NSPS
Not Applicable

- Not covered in 2012 NSPS
- Control Options
  - Reduced Emission Completions
  - Combustion
- Pre-panel SER written comments
  - Exempt low producing wells
  - Exempt low pressure wells
  - Exempt low gas-to-oil ratio (GOR) wells
- Input requested from SERs
  - Appropriate production threshold (e.g. stripper well - 15 barrels per day – 22% of wells)
  - Appropriate pressure threshold- are there particular considerations for oil wells?
  - Is the use of GOR an appropriate approach for establishing a threshold (e.g., 300 or 500 scf gas per barrel, 24% and 30% of wells respectively)?

Hydraulically Fractured Oil Well Completions – Control Options

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Reduced Emission Completions	"Green" or "flareless" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator. Portable equipment used for RECs can operate in tandem with the permanent equipment that will remain after well drilling is completed.	Some limitations exist for performing RECs since technical barriers fluctuate from well to well: proximity of pipelines, pressure of produced gas, and inert gas concentration. Emissions reductions will vary according to reservoir characteristics and other parameters. Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.	Equipment costs associated with RECs vary from well to well. A REC lasting 7 days is estimated to be between \$10,000 and \$15,000 per completion.
Combustion	Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.	Combustion devices are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. The flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency.	Combustion estimated annual cost ranges between \$3,000 and \$4,000 per well completion.

Fugitive Emissions



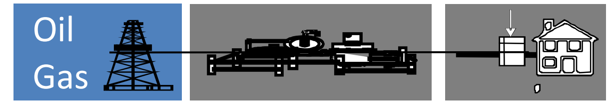
White Paper Source
2012 NSPS
Not Applicable

- 2012 NSPS includes equipment leaks (at natural gas processing plants)
- Control Options
  - Optical Gas Imaging – "Infrared Camera"
  - Method 21
  - Frequency of surveys (e.g., annual, semiannual, quarterly)
- Pre-panel SER written comments
  - Concerned about overburdening small operators
  - Recommended against using Colorado Regulation 7 LDAR program as a model (We heard: burdensome with little environmental benefit, frequency of inspections and reporting too costly, lack of air quality modeling to quantify expected reductions, loss of marginal wells)
- Input requested from SERs
  - Expand on issues with Colorado Regulation 7 implementation
  - Appropriate exemption threshold (e.g. 2.7 tons per year in PA, low producing wells or stripper wells)
  - Feedback on appropriate flexibility or exclusions under certain circumstances

Fugitive Emissions – Control Options

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Optical Gas Imaging Infrared Camera	OGI operates much like a consumer video-camcorder and provides a real-time visual image of hydrocarbon gas emissions or leaks to the atmosphere. The OGI camera works by using spectral wavelength filtering and an array of IR detectors to visualize the IR absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged.	OGI instrument can be used for monitoring a large array of equipment and components at a facility, and is an effective means of detecting leaks when the technology is used appropriately. Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent.	It is believed that the OGI system can reduce the cost of identifying fugitive emissions at oil and natural gas facilities when compared to using a handheld TVA or OVA. The annual cost for OGI (well pads) ranges between $1,500 and $2,000; OGI (gathering/boosting) ranges between $9,000 and $10,000; and OGI (transmission/storage) ranges between $13,000 and $23,000. The annual cost for Method 21 (well pads) ranges between $1,500 and $3,000; Method 21 (gathering/boosting) ranges between $10,000 and $15,000; and Method 21 (transmission/storage) ranges between $7,000 and $25,000.
Frequency of Surveys	The reduction of fugitive emissions involves the development of a fugitive emissions monitoring plan. An exemplary plan may incorporate semiannual survey.		The estimated annual cost of monitoring fugitive emissions will vary based on the frequency of the monitoring plan activities and type of monitoring.

Pneumatic Pumps



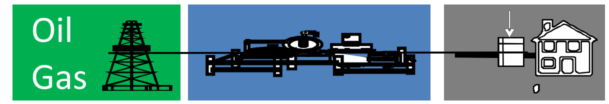
White Paper Source
2012 NSPS
Not Applicable

- Not covered in 2012 NSPS
- Control Options
  - Instrument (compressed) Air
  - Switch to solar-powered or electric-powered
  - Route to a control device (e.g. combustion or vapor recovery)
- Pre-panel SER written comments
  - Gas processing plants have a very small number of pneumatic pumps, and provide little benefit in emissions reductions from gas processing.
- Input requested from SERs
  - What is the prevalence of control devices already at your facilities?
  - Are there site characteristics that make control devices more prevalent? (e.g. storage vessels)

Pneumatic Pumps – Control Options

Option	Description	Applicability/Effectiveness	Estimated Cost Range
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, when applicable can result in 100 percent reduction in emissions where applicable.	Capital costs for converting to solar pumps is approximately $2,300 per device
Covert 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 $1,800 to $5,500 plus electricity costs and an average annual maintenance cost of $260 per device.
Convert to Instrument Air	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.	System costs are dependent on size of compressor, power supply needs, labor and other equipment. Estimated annualized range is between $800 and $8,000.
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 CH_4 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.	Costs will vary depending on the distance of pipeline necessary, but annualized cost is estimated between $200 and $300.
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 CH_4 emissions by 95 percent.	Capital costs will be approximately $48,000 with annual costs around $105,000.
Route Natural Gas to Existing Gas Capture System	Routing natural gas from a gas-driven pump entails piping to a vapor recovery unit (VRU).	Routing natural gas-driven pumps to a VRU reduces VOC and CH_4 emissions through gas capture where emission reduction efficiencies are typically 95 percent.	Capital costs will vary depending on the distance of pipeline necessary, but are estimated to be approximately $1,500 per device.

Pneumatic Controllers



White Paper Source
2012 NSPS
Not Applicable

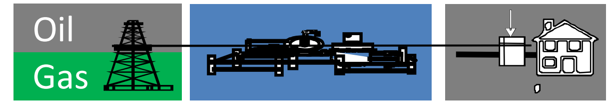
- 2012 NSPS covers pneumatic controllers in the production and processing segments
- Control Options
  - Low bleed
  - Instrument (compressed) air
  - Mechanical or solar-powered systems
  - Enhanced maintenance
- Pre-panel SER written comments
  - Instrument air systems are cost prohibitive for small gas processing operations
- Input requested from SERs
  - How many small entities own gas processing plants?
  - What is the prevalence of instrument air at gas processing plants?

Pneumatic Controllers – Control Options

Option	Description	Applicability/Effectiveness	Estimated Cost Range
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 $160 more than high bleed versions. Annualized cost ranges $20 to $30.
Convert to Instrument Air	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.	System costs are dependent on size of compressor, power supply needs, labor and other equipment. Annualized cost is estimated to be between $2,000 and $20,000.
Mechanical and Solar Powered Systems in place of Bleed Device	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.

Deliberative - Do Not Cite or Quote

Compressors



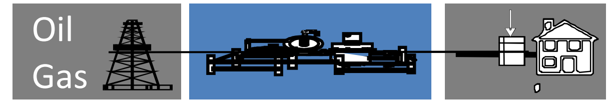
White Paper Source
2012 NSPS
Not Applicable

- 2012 NSPS covers compressors in the gas production & processing segments; exempts well site compressors
- Control Options
  - Reciprocating Compressors
    - Rod-Packing Replacement
  - Centrifugal Compressors
    - Dry Seals
    - Wet Seal with a Flare
    - Wet Seal with gas recovery
- Pre-panel SER written comments
  - Upstream compressor controls are extremely burdensome to small operators
  - Vapor recovery systems are cost prohibitive
- Input requested from SERs
  - How would you characterize a “small” compressor?
  - Where are “small” compressors located and used?

Compressors – Control Options

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Reciprocating Compressors Rod Packing Replacement	Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces CH_4 and VOC emissions.	Piston rods, wear more slowly than packing rings, having a life of about 10 years. We assume operators will choose, at their discretion, when to replace the rod.	The estimated rod replacement cost range is between $1,700 and $2,100.
Centrifugal Compressors Dry Seals	Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs.	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.	The replacement of wet seals with dry seals is estimated cost savings range of $80,000 to $90,000.
Centrifugal Compressors Wet Seal with flare or gas recovery	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 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.	As a control measure, the recovered gas would then be sent to a combustion device or other process.	The annual cost of wet seal with gas recovery ranges between $3,000 and $5,000.

Liquids Unloading



White Paper Source
2012 NSPS
Not Applicable

- Not covered in 2012 NSPS
- Control Options
  - Route Emissions to Flare
  - Plunger Lift Systems
  - Artificial Lift Systems
  - Velocity Tubing
  - Foaming Agents
- Cost is highly variable based on well characteristics
- Pre-panel SER written comments
  - Noted complexity of well liquid unloading
  - Regulatory uncertainty
- Input requested from SERs
  - During a blowdown, is it feasible for emissions to be routed to a flare?
  - What are the techniques you currently use?
  - Do you have an estimated number of potentially affected sources?

Reporting & Recordkeeping

- Options
  - Retain 2012 REC-PIX alternative
  - Electronic reporting
- Pre-panel SER written comments
  - Limitation of small number staff
  - High cost and difficulty of obtaining third-party contractors
  - Concerned with duplicative efforts
- Input requested from SERs
  - Please share other ideas to help streamline potential duplications.
  - Are you familiar with the REC-PIX alternative to well completion reporting in the current NSPS (2012)?
  - Do you find the provision for well completion notification helpful in reducing duplicative reporting (notification under a state or local requirement satisfies the NSPS)?

Number of Potentially Affected Sources

Emissions Source	No. Of Potentially Affected New Sources Annually
Oil Well Completions	10,000 to 20,000
Fugitive Emissions	15,000 to 25,000
Pneumatic Pumps	2000 to 3000
Compressors	50 to 100
Pneumatic Controllers	200 to 300
Liquids Unloading	unknown

Unit Reductions and Costs from Potential Control Options

Emissions Source	Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
		Methane	VOC	Methane	VOC		
Oil Well Completions	Reduced Emission Completion	9-10	8-9	9-10	7-8	800-900	$10,000-$15,000
	Combustion	9-10	8-9	9-10	7-8	0	$3,000-$4,000
Fugitive Emissions - Well Pads	OGI	1-5	0-2	0-4	0-2	30-160	$1,500-$2,000
Fugitive Emissions - Gathering/Boosting Stations	OGI	30-40	9-10	10-35	3-8	1,100-1,300	$9,000-$10,000
Fugitive Emissions - Transmission and Storage Compressor Stations	OGI	60-170	1-5	20-140	0-4	1,500-5,500	$13,000-$23,000
Pneumatic Pumps – Production and Processing	Route Emissions to Existing Control Device	0-4	0-1	0-4	0-1	0	$200-$300
	Instrument Air	0-4	0-1	0-4	0-1	0	$800-$8,000
Pneumatic Pumps – Transmission and Storage	Route Emissions to Existing Control Device	0-4	0-1	0-4	0-1	0	$200-$300
	Instrument Air	0-4	0-1	0-4	0-1	0	$800-$8,000
Compressors	Rod Packing Replacement	25-35	0-1	20-30	0-1	1,000-1,200	$1,700-$2,100
	Replace Wet Seals with Dry	100-160	3-5	100-140	3-5	5,000-6,000	($80,000) to ($90,000)
	Wet Seal with Gas Recovery	100-160	3-5	100-160	3-5	5,000-6,000	$3,000-$5,000
	Route Emissions to Control	100-160	3-5	100-150	3-5	0	$110,000-$120,000
Pneumatic Controllers	Install Low- or No-bleed Controllers	3-4	0-1	2-4	0-1	140-150	$20-$30
	Instrument Air	3-4	0-1	3-4	0-1	140-150	$2,000-$20,000

Additional SER Input Requested

The Regulatory Flexibility Act (RFA) statute directs the Panel to collect advice and recommendations from SERs on issues related to:

- 603(b)(3) a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- 603(b)(4) a description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
- 603(b)(5) an identification, to the extent practicable, of all relevant federal rules which may duplicate, overlap or conflict with the proposed rule
- 603(c) each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities; consistent with the stated objectives of applicable statutes, the analysis shall discuss significant alternatives such as:
  - The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;
  - The clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;
  - The use of performance rather than design standards; and
  - An exemption from coverage of the rule, or any part thereof, for such small entities

Next Steps

- In addition to comments we heard today, written comments will be accepted by the panel (EPA, OMB, and SBA) by June 29, 2015.
- Final report of this panel process will be developed in the July timeframe
- Proposal of the NSPS planned for summer 2015

Panel Outreach Briefing

Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector Supplemental Information

Analysis Assumptions:

- Control technologies with both capital and operating costs are annualized over the assumed technology life using a 7% interest rate.
- Cost analysis are based on model facilities and typical costs.

Oil Well Completions:

- Activity data
  - Baseline completions count based on HPDI dataset for 2012. Classification of oil wells based on gas-to-oil ratio (GOR).
  - Projection of change in completions from 2012 through analysis years based on projections in AEO14/NEMS.
  - Classification of development versus delineation/exploration wells based on AEO14/NEMS.
- Emissions
  - Emissions per day based on gas production in the first month from HPDI.
  - Assumption of 3 days per oil well completion based on white papers.
  - Reduction rate of 95% for combination of REC and flare based on white papers.
  - Assumption that RECs will be feasible for 50% of oil well completions (whereas for the remainder RECs will likely be infeasible for some combination of unavailability of infrastructure or other technical considerations).
- Costs
  - Costs per day for REC equipment based on white paper and 2012 NSPS supplemental TSD, adjusted for inflation.
  - Costs per completion combustion device based on 2012 NSPS Supplemental TSD, adjusted for inflation.

Fugitive Emissions:

- Activity data
  - Baseline well pad counts based on HPDI dataset for 2012.
  - Assumed 2 wells per pad based on geographic analysis of HPDI dataset for 2012.
  - Projected change in wellpads from base year to projection years based on AEO14/NEMS.
  - Typical new compressor stations per year based on historical average of increases in the number of compressor stations in the 2012 U.S. GHG Inventory (published April 2014).
  - Equipment and component counts per gas well and compressor station based on GRI/EPA, which underlies the U.S. GHG Inventory for this source. Equipment and component counts for oil wells based on GHG Inventory.

- Emissions
  - Emissions factors per component based on AP-42.
  - Reduction percentages based on expert judgement and the range of emissions reductions from the white paper.
- Costs
  - Costs for OGI surveys based on white papers and comparison to other analyses such as Carbon Limits and Colorado rule analysis. Costs for repairs, overhead, planning, and program support based on per-hour estimates and typical labor rates.

Pneumatic Pumps:

- Activity data
  - Typical new pneumatic pumps per year based on historical average of increases in number of pumps per year from the U.S. GHG Inventory.
  - Consideration of two pump types/sizes (diaphragm/heat-trace and piston/plunger pump).
  - Pumps primarily analyzed at well sites.
  - Consideration of pumps located at sites where controls are already present (e.g., for a storage vessel or wet seal compressor) versus pumps located at sites without existing controls.
- Emissions
  - Reduction percentage of 95% based on white papers.
- Costs
  - Costs for control devices and piping based on typical cost assumptions.

Pneumatic Controllers:

- Activity data
  - Typical new high-bleed pneumatic controllers based on historical average of increases in number such controllers in the U.S. GHG Inventory.
  - Assumption that a portion of high-bleed pneumatic controllers are needed for operational reasons and cannot be replaced with low-bleed controllers.
- Emissions
  - Emissions per controller based on white paper and 2012 NSPS analysis.
- Costs
  - Costs based on incremental cost difference between a low-bleed and high-bleed pneumatic controller, from white paper and 2012 NSPS analysis.

Compressors:

- Activity data
  - Typical new wet seal compressors and reciprocating compressors in transmission and storage based on historical average of increases in number of such controllers in the U.S. GHG Inventory.

- Emissions
    - Emissions per compressor based on white paper and 2012 NSPS analysis.
- Costs
    - Costs based on white paper and 2012 NSPS analysis.

Panel Outreach Briefing (Update 6/26/2015)

Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector Supplemental Information – Slide 20 Data and Assumptions

Oil Well Completions

Emissions Source	Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
		Methane	VOC	Methane	VOC		
Oil Well Completions	Reduced Emission Completion	9-10	8-9	9-10	7-8	800-900	$10,000-$15,000
	Combustion[1]	9-10	8-9	9-10	7-8	0	$3,000-$4,000

Baseline Emissions

- Based on 3-day completion or recompletion event.
- The average daily production of natural gas was estimated using data on gas production from oil wells (with gas to oil ratio of 300-100,000)[2] in the DrillingInfo database for CY 2012. We used the average daily production from the first month of production. This average daily production was then multiplied by 3 for the average production from a 3-day completion event.
- Potential Emissions: CH4 9.72 tons/event and VOC 8.14 tons/event. Calculated from natural gas production per event. It is assumed CH_4 comprises 46.732 percent by volume of natural gas. (Factors: 0.0208 tons CH_4 per Mcf and 0.8374 lb. VOC/lb. CH_4)[3]

Emission Reductions

- Reduced Emission Completions
  - Assumes 90 percent of flowback gas can be recovered during a REC
    - Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. Percent of Emissions Recovered by Reduced Emission Completions. May 2011.
  - Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.
    - 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. (2011 TSD, p 4-28)
- Combustion
  - Assumes destruction efficiency of 95 percent, consistent with the expected destruction efficiency of a properly designed and operated flare for completion combustion devices over the duration of the completion or recompletion. (2011 TSD, p. 4-19)

Cost

- Reduced Emission Completion
  - The annual cost of performing a REC was estimated to be $12,735 ($13,459 in 2012$) for a representative well completion lasting 3 days. 2011 TSD, page 4-16.

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[1] Consistent with the 2012 NSPS, EPA is considering a tiered approach for reducing emissions from oil well completions. For - example, REC will be required where feasible, and combustion where an REC is not feasible. -

[2] EPA is only considering regulating hydraulically fractured or refractured oil wells with gas oil ratios greater than 300. -

[3] 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.

- Assumes the cost to rent equipment to perform a REC for an oil well completion costs the same per day as the cost analysis for gas well completions.
- Combustion
  - Estimated average completion combustion device cost of approximately $3,523 (2008 dollars) (2011 TSD, pp. 4-19 to 4-20)

Fugitive Emissions

Emissions Source	Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
		Methane	VOC	Methane	VOC		
Fugitive Emissions - Well Pads	OGI	1-5	0-2	0-4	0-2	30-160	$1,500-$2,000
Fugitive Emissions - Gathering/Boosting Stations	OGI	30-40	9-10	10-35	3-8	1,100-1,300	$9,000-$10,000
Fugitive Emissions - Transmission and Storage Compressor Stations	OGI	60-170	1-5	20-140	0-4	1,500-5,500	$13,000-$23,000

Baseline Emissions

- Equipment and component counts per gas well and compressor station based on GRI/EPA, which underlies the U.S. GHG Inventory for this source. Equipment and component counts for oil wells based on GHG Inventory. Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA-600/R-96-080h). http://www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf

Emission Reduction

- Emissions factors per component based on AP-42.
  - U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017) http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf
- Emission reductions from the implementation of an OGI monitoring program varied from 40 to 80 percent (assumptions: 40% - annual inspections; 60% - semiannual inspections; 80% - quarterly monitoring).
- Ranges account for the varying efficacies of quarterly, semiannual, and annual monitoring.

Costs

- Costs for OGI surveys based on white papers and comparison to other analyses such as Carbon Limits and Colorado rule analysis. Costs for repairs, overhead, planning, and program support based on per-hour estimates and typical labor rates.
  - Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9).* November 15, 2013. https://www.colorado.gov/pacific/sites/default/files/062_R7-Initial-EIA-request-11-21-13-26-pgs-062_1.pdf
  - Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras.* December 24, 2013. http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf
  - Labor rate: $57.80/hour. Source: Table 11 of the Uniform Standards memo - Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.

Pneumatic Pumps

Emissions Source	Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
		Methane	VOC	Methane	VOC		
Pneumatic Pumps – Production and Processing	Route Emissions to Existing Control Device	0-4	0-1	0-4	0-1	0	$200-$300
	Instrument Air	0-4	0-1	0-4	0-1	0	$800-$8,000
Pneumatic Pumps – Transmission and Storage	Route Emissions to Existing Control Device	0-4	0-1	0-4	0-1	0	$200-$300
	Instrument Air	0-4	0-1	0-4	0-1	0	$800-$8,000

Baseline Emissions

- Ranges primarily based on differences between piston and diaphragm pumps
- Piston Pumps: Methane emissions range from 0-0.5 tpy; VOC from 0-0.25 tpy; varying based on location
- Diaphragm Pumps: Methane emissions range from 3-4 tpy; VOC from 0.5-1 tpy; varying based on location
- Data Sources: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps

Emission Reductions

- Route to Control - Capture systems combined with combustion devices are considered a reliable mechanism to reduce approximately 95 percent of emissions (2011, TSD, p. 6-23)
- Instrument Air - Reductions over 95% (U.S. EPA. PRO Fact Sheet No. 202. Convert Natural Gas-Driven Chemical Pumps.)

Costs

- Route to Control
  - Capital cost for installing a new combustion device is $34,250 and the annual operating costs are $17,001 in 2012 dollars. In the 2012 supplemental TSD, the combustor cost was estimated to be $32,301 in 2008 dollars (see Table 7-5, p. 7-6). This was escalated to $34,250 in 2012 dollars.
- Instrument Air
  - Replacing Gas-Driven Pumps with Instrument Air System – annualized cost: Small plants – $10,000 to $15,000; Medium plants - $30,000 to $40,000; Large plants -$70,000 to $80,000
  - Based on model plants with 4, 10, 20, 50, and 100 pumps, with varying distribution scenarios between diaphragm and piston pumps (ie, 50/50;75/25; 25/75)
  - 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 (2011 TSD, Table 5-10, p. 5-21.)
  - We estimate 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.
    - The natural gas emission factor for a diaphragm to be 22.45 scf/hr. Thus, (22.45 scf/hr x 8760 hrs/yr)/1000 = 197 Mcf/yr. Cost savings: 197 Mcf x $4/Mcf = $786
  - The natural gas emission factor for a piston pump to be 2.48 scf/hr. Thus, (2.48 scf/hr x 8760 hr/yr)/1000 = 22 Mcf/yr. Cost savings: 22 Mcf x $4/Mcf = $87

- EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.

Compressors

Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
	Methane	VOC	Methane	VOC		
Rod Packing Replacement	25-35	0-1	20-30	0-1	1,000-1,200	$1,700-$2,100
Replace Wet Seals with Dry	100-160	3-5	100-140	3-5	5,000-6,000	($80,000) to ($90,000)
Wet Seal with Gas Recovery	100-160	3-5	100-160	3-5	5,000-6,000	$3,000-$5,000
Route Emissions to Control	100-160	3-5	100-150	3-5 -	0	$110,000-$120,000

Baseline Emissions

- Reciprocating - The methodology for estimating emission from reciprocating compressor rod packing was to use the CH4 emission factors referenced in the EPA/GRI study[4] and the CH4-to-VOC ratio developed in the gas composition memorandum.
- Centrifugal - The compressor emission factors for wet seals and dry seals are based on data used in the GHG Inventory[5]. The wet seals CH4 emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal CH4 emission factor was based on data collected by the Natural Gas STAR Program.

Emission Reductions

- Reciprocating
  - 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 and the average emission factor for newly installed rod packing.
- Centrifugal
  - Dry seals - The dry seal emission factor is based on information from the Natural Gas STAR Program.[6]
  - Route to Control - A combustion device typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions (2011 TSD p. 6-23)

Cost

- Reciprocating
  - Replacement of the packing rings to be $1,712 per cylinder
    - http://www.epa.gov/gasstar/documents/ll_rodpack.pdf. Average cost in NGSTAR data was $1,620 which was converted to 2012 dollars for our assessment.
    - On average, each reciprocating compressor has 3.3 cylinders.
  - Replace every three years, during planned shutdowns and maintenance

[4] 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.
[5] U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014.
[6] U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR. 2006.

- Centrifugal
  - Dry seals - Annual operation and maintenance savings from the installation of dry seal compressor is $88,300 in comparison to wet seal compressor.
    - http://www.epa.gov/gasstar/documents/ll_wetseals.pdf. See p. 4, Exhibit 4.
  - Route to Control - The capital and annual cost of the combustion device was calculated using the methodology in the EPA Control Cost Manual.[7]

Controllers

Emissions Source	Control Options	Baseline Emissions (tons per year)		Emission Reduction (tons per year)		Natural Gas Product Recovery (Mcf/year)	Annualized Cost with Savings (2012$)
		Methane	VOC	Methane	VOC		
Pneumatic Controllers	Install Low- or No-bleed Controllers	3-4	0-1	2-4	0-1	140-150	$20-$30
	Instrument Air	3-4	0-1	3-4	0-1	140-150	$2,000-$20,000

Baseline Emissions

- Low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh and high-bleed devices vary significantly from venting as low as 7 scfh to as high as 100 scfh.
  - U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.
  - EPA determined that best available emissions 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)
  - http://www.gpo.gov/fdsys/pkg/CFR-2012-title40-vol22/pdf/CFR-2012-title40-vol22-sec98-238-appW.pdf

Reductions

- Low Bleed
  - 95% reduction from low-bleed devices - calculated from GHGRP data considering the difference between the emissions of a high-bleed and low-bleed device.
  - Table W-1A of the GHG Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W)
- Instrument Air
  - These systems can achieve 100 percent reduction in emissions.

Costs

- Low Bleed
  - The average cost for a high bleed pneumatic is $2,471, while the average cost for a low bleed is $2,698. - incremental cost of installing a low-bleed device instead of a high-bleed device is ~$227 per device -
    - 2011 TSD, Table 5-7, p. 5-15. The values from this table were escalated to 2012 dollars. -
  - 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.
  - 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 (2011 TSD, p. 5-15).
- Instrument Air

[7] EPA Air Pollution Control Cost Manual - Sixth Edition, (EPA 452/B-02-001).

- System costs are dependent on size of compressor, power supply needs, labor and other equipment.[8]

Overall Assumptions and Links

- Unless otherwise specified, all costs are 2012$
- 2011 TSD: 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. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf
- 2012 TSD: 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. http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

[8] 2011 TSD discusses the costs of instrument air requirements for gas processing plants, which may be considered an analogous requirement here.