Appointment

From: Davis, Matthew [Davis.Matthew@epa.gov]
Sent: 4/26/2017 4:21:49 PM
To: Davis, Matthew [Davis.Matthew@epa.gov]; Ashley, Jackie [Ashley.Jackie@epa.gov]; Gunning, Paul [Gunning.Paul@epa.gov]; DCRoomARN3428/OCIR [DCRoomARN3428@epa.gov]; Cozzie, David [Cozzie.David@epa.gov]
CC: VonDemHagen, Rebecca [VonDemHagen.Rebecca@epa.gov]; Harvey, Reid [Harvey.Reid@epa.gov]; Krieger, Jackie [Krieger.Jackie@epa.gov]; Clarke, Deirdre [clarke.deirdre@epa.gov]; Weitz, Melissa [Weitz.Melissa@epa.gov]; Kocchi, Suzanne [Kocchi.Suzanne@epa.gov]

Subject: Confirmed: Background briefing on oil and gas related programs for Senate Energy and Nat Resources minority staffer
Attachments: OilGas-Air-Overview-May9.pptx
Location: North room 3428, 866-299-3188 code: Ex. 6 Personal Privacy (PP)

Start: 5/9/2017 8:00:00 PM
End: 5/9/2017 8:45:00 PM
Show Time As: Busy

UPDATE: Slides were reviewed by my political management, and the last three slides were asked to be struck before I send it to the staffer on the Hill.

A new staffer at Senate Energy and Natural Resources, Faye Matthews, is looking for a background briefing on what programs or efforts EPA has on oil and gas industry, broadly speaking. She's talking with all the various agencies that have some jurisdiction so that she has a better sense for who does what.

Wednesday May 3rd didn't work for the staffer; she's at a conference most of the week, so she suggested the week of 5/8. I'm trying to schedule around the Regional Congressional Liaisons and Public Affairs Directors meeting 5/10-5/11 (though once I see a draft agenda I might be able to use time on those days), and a trip to Ann Arbor 5/8 and morning of 5/9.

Message

From: Sandra Snyder [Ssnyder@ingaa.org]
Sent: 6/21/2018 8:59:14 PM
To: kevin.bromberg@sba.gov; Cozzie, David [Cozzie.David@epa.gov]
Subject: NSPS OOOOa Supplement
Attachments: IES Memo_Supplement to OOOOa White Paper on Survey Frequency and TSD_062118.pdf

Kevin and David,
Attached please find a supplement the provides further clarifications on the white paper that INGAA shared with EPA. These explanations may be helpful as you review the white paper.

Regards,

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MEMORANDUM

Date: June 20, 2018

To: Sandra Snyder, INGAA

From: Jim McCarthy and Tom McGrath, Innovative Environmental Solutions, Inc.

Re: Supplement to INGAA White Paper on Subpart OOOOa TSD Estimates of Leak Emissions and LDAR Performance

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INGAA submitted to the U.S. Environmental Protection Agency (EPA) a White Paper dated June 8, 2018 that presents information related to the technical basis for leak detection and repair requirements in Subpart OOOOa. The White Paper discusses more recent data on leak emissions from natural gas transmission and storage facilities and contrasts this new data with estimates that were used in EPA's Subpart OOOOa Technical Support Document (TSD), information on leak estimates from a California Air Resources Board (CARB) report, and a Canadian study that provides insight into leak mitigation control effectiveness (CE) as a function of leak survey frequency. The White Paper discusses implications for the Subpart OOOOa TSD analysis. Several questions were raised regarding quantitative values for some of the data, and cost per ton implications. This memo is intended to supplement the White Paper to provide additional explanation.

<u>INGAA White Paper Section 4 – CARB Study: Leak Emissions and Tabular Presentation of Leak Rates</u>

Section 4 of the INGAA White Paper cites a 2017 report from CARB that developed leak estimate correlation equations based on the screening value measured using EPA Method 21 and measured leak rates for different component types. Figures 4-1 and 4-2 of the White Paper present calculated emission rates by component type based on the CARB correlation equations.

The CARB report includes measurements from one hundred and sixty (160) leaking components at thirty-nine (39) sites. A Thermo Scientific Toxic Vapor Analyzer (TVA) was used to detect component leaks by EPA Method 21. The TVA detects hydrocarbon leaks between 1 and 50,000 ppm with a flame ionization detector (FID). When the Method 21 screening values (SVs) were greater than 50,000 ppmv, a calibrated dilution probe was used to reduce the leak sample hydrocarbon concentration. Component leak rates were measured with a Bacharach Hi Flow Sampler® and the leak rates were calculated as methane-equivalent total organic compounds (TOC). Table 1-1 from the CARB report, which summarizes the measurement counts by component type, is provided below.

"(CARB) Table 1-1 Completed Sample Test Matrix

Type Gas Service	EPA Method 21 Reading, ppmv CH4					
	0 - < 100	1000 - < 1K	1K - < 10K	10K - < 100K	>= 100K	Sum
Valves	7	7	6	7	6	33
Connectors	6	8	9	6	8	37
Flanges	7	6	6	1	2	22
(Connectors + Flanges)	13	14	15	7	10	
OELs	9	6	4	7	8	34
Other[A]	6	6	6	8	8	34
TOTAL	48	47	46	36	42	160

A. The "Other" group, included gas regulators, pressure gauges, pressure relief devices (PRD), flow and pressure meter fittings, pneumatic devices, compressor vents, temperature controllers, and inactive flare pilots."

The INGAA White Paper includes various data and information in graphs (e.g., bar charts) and tables. For graphical presentation, it is sometimes difficult to ascertain the specific level of emissions – e.g., due to the y-axis scale and some results near zero. In Section 4 of the INGAA White Paper, Figures 4-1 and 4-2 show the estimated emission rate as a function of screening value for the CARB correlation equations. This figure is provided below, and the results are also presented in tabular form in Table 1. There are a few minor differences between the figure below and the one in the White Paper; INGAA has edited Figure 4-1 below to correct one erroneous point for open ended lines, and to improve the graph symbols so that "valves" are more clearly visible (i.e., symbols are partially hidden by other data). Table 1 below was not included in the White Paper. As the figure and table show, the leak rates are very small in nearly all cases. For example, a leak rate of 1.1 x 10^{-4} kg/hr is equivalent to approximately 1 kilogram *per year* (assuming that the leak continues at the same rate for an entire year).

Figure 4-1(from INGAA White Paper):
Leak Rate Versus Method 21 SV Correlation Equations by Component Type (log-log scale).

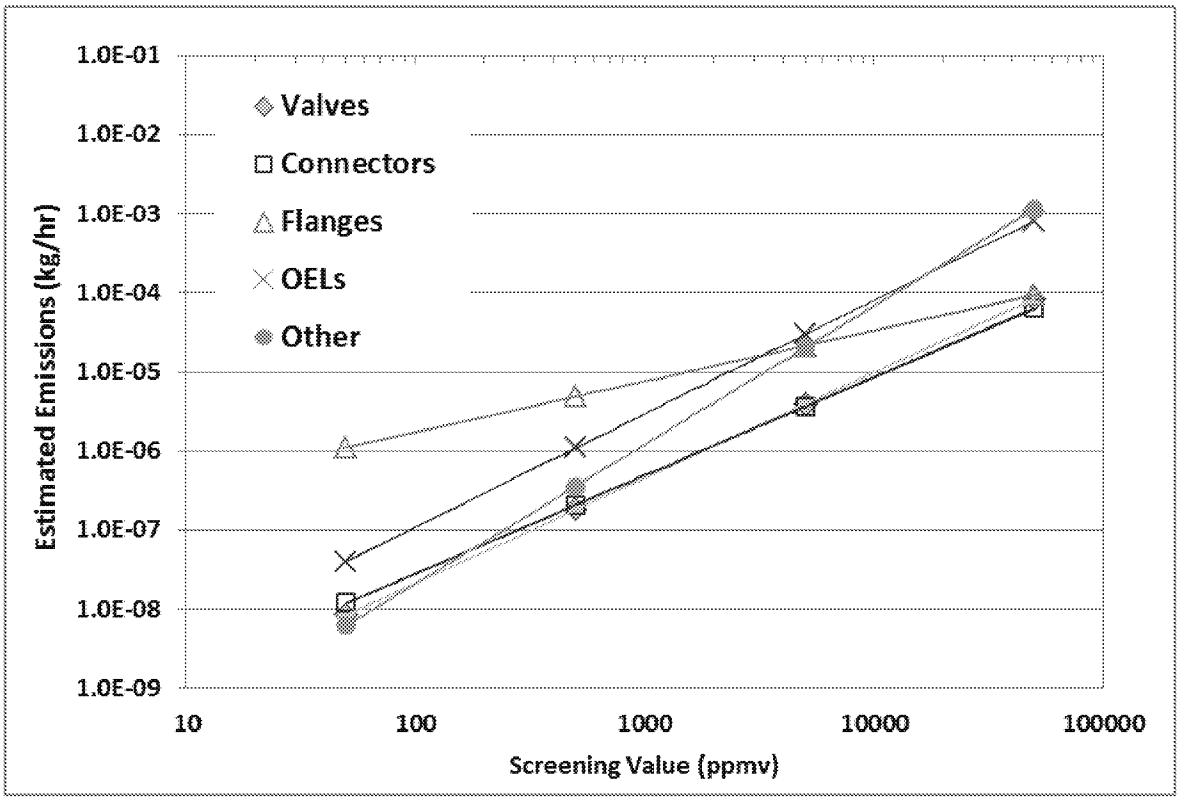


Table 1. Gas Leak Rate Estimates by Component Type versus Method 21 Screening Value (from CARB Correlation Equations for Components in Natural Gas Service).

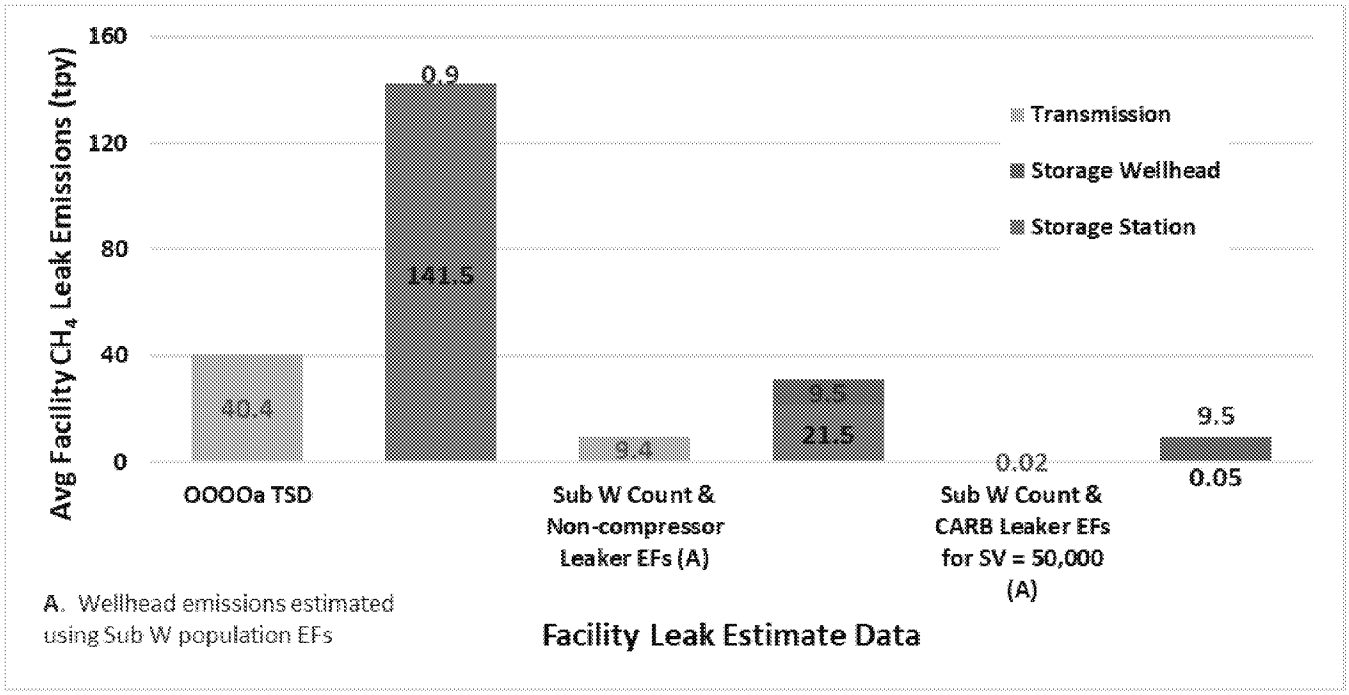
Component Type	Method 21 Screening Value			
	50	500	5,000	50,000
	Estimated Average Leak Rate (kg/hr)			
Valves	8.5E-09	1.8E-07	3.9E-06	8.4E-05
Connectors	1.2E-08	2.1E-07	3.7E-06	6.4E-05
Flanges	1.1E-06	4.9E-06	2.1E-05	9.4E-05
OELs	4.1E-08	1.1E-06	3.0E-05	8.1E-04
Other components	6.1E-09	3.5E-07	2.0E-05	1.1E-03

INGAA White Paper Section 5 – Subpart OOOOa TSD Model Plant Leak Emissions Estimates

Section 5.1 of the INGAA White Paper presents transmission and storage leak emission estimates from the TSD "model facilities" and compares them to emission estimates based on other data and information sources (e.g., Subpart W leaker emission factors and survey leak counts; CARB correlation equations). See Figure 5-1 of the White Paper for additional details. A similar version of that figure is provided below with the bars labeled to more clearly present the data. This information is not separately provided in a tabular format because the numerical values are shown directly in the figure. The first set of bars in the figure present the TSD estimates for compressor stations and for storage facilities. The middle set of bars estimate the leak emissions based on leak counts from Subpart W surveys and Subpart W emission factors. The third set of bars estimate leak emissions based on Subpart W leak survey counts and the CARB correlation equations for compressor stations and storage facilities (exclusive of well leak estimates). A very high screening value (50,000 ppm) was assumed for the CARB correlation equations, but leak emissions from facility components are miniscule (less than 0.1 TPY). That TPY rate is significantly lower than the TSD model facility estimates of about 40 TPY for transmission compressor stations and 142 TPY for storage facilities.

As the figure shows, using the alternative methods for estimating model plant emissions results in much lower emissions from component leaks than using the TSD value, which in turn has significant implications for the reductions that are calculated based on the model T&S facilities and the resulting cost per ton. If a more reasonable screening value was used with the CARB correlation equations (e.g., 5,000 ppm), the estimated emissions would be less than 0.01 TPY.

Figure 5-1 (from INGAA White Paper). Estimated CH_4 leak emissions based on various component counts and emission factor data for Transmission model plants and Storage model plants



TSD Estimates of LDAR Cost Effectiveness: Revised Estimates of Cost-Effectiveness Based on CAPP LDAR Control Efficiency Data and PRCI / Subpart W Leak Emissions Data

The Subpart OOOOa TSD provided calculated estimates of LDAR cost-effectiveness using different leak survey frequencies and associated assumed control efficiencies (CEs). Baseline (i.e., pre-LDAR) component leak emissions were calculated for model plants. The transmission station model plant and the storage station model plant were based on non-compressor component leak data in the 1996 GRI/EPA Study.[1] Model plant emissions were calculated based on average facility non-compressor component counts and associated population emission factors (EFs). The INGAA White Paper (and discussion throughout this supplement) explains that both the LDAR CEs and baseline model plant emissions assumptions are not representative of current leak emissions at T&S facilities. Specifically:

- White Paper Section 2 demonstrated that TSD CEs associated with OGI monitoring (refer to "(TSD) Table 4-17" in Section 2) were based on a LDAR CE model with high uncertainty and biased by flawed and unrepresentative data and assumptions. Measured leak CEs from a Canadian Association of Petroleum Producers (CAPP) study are more accurate and reliable estimates; and
- The TSD model plant emissions may not represent current leak emissions at T&S facilities because the population EFs are based on measurements collected about 25 years ago. Section 5.1 (see Figure above) presented revised estimates of Subpart OOOOa T&S model plant emissions based on PRCI / Subpart W data, and these estimates are believed to be more representative of current natural gas operations than the estimates from the TSD model plant.

Table 2 below presents TSD transmission model plant emission reduction estimates and associated cost data (i.e., LDAR capital costs, annual costs, and LDAR cost-effectiveness ($/ton emission reduction))

[1] Methane Emissions from The Natural Gas Industry, Volume 8: Equipment Leaks, GRI-94/0257.25, EPA-600/R-96-080h, June 1996.

from the TSD, and compares the TSD value to the LDAR emission reduction and cost-effectiveness values determined using the CAPP study CEs and the Subpart W data-based model plant emissions. Table 3 presents the same information for the TSD storage model plant and alternative estimates. Tables 2 and 3 consider the facility leak estimates based on the first two sets of bars from Figure 5-1 above.[2] The information in the "Model Plant Scenario" and "Notes" columns of Tables 2 and 3 describe the data that are the basis for the emission reductions and costs. INGAA did not scrutinize the cost data (e.g., cost of repair) or the assumptions used in the TSD to estimate LDAR cost-effectiveness when preparing this supplement. However, one error was noted in the TSD analysis where the cost per ton included annual costs but excluded the annualized cost of initial / capital costs. That cost should be included, and, depending on assumptions regarding cost amortizations, adds approximately 10% to the costs presented in the TSD.

In Table 2, the first row of data (i.e., Row 1) are the emission reductions, costs, and cost-effectiveness (i.e., $/ton emission reduction) data that the TSD EPA used to support the Subpart OOOOa LDAR requirements for transmission compressor stations (i.e., quarterly LDAR surveys for 80% CE). Key comparisons include:

- Row 6: Annual monitoring with 80% CE (supported by the CAPP data), produces the same emissions reductions as the TSD quarterly LDAR but with less than half the cost per ton emissions reduction. Row 2 $/ton (quarterly monitoring with 90% CE estimated from the CAPP data) are more twice the Row 6 $/ton but emissions reductions only improved by 10%. These greatly diminishing returns for increased monitoring frequency support annual (or less frequent) LDAR monitoring.
- Row 3: Quarterly monitoring with 80% CE and baseline (i.e., pre-LDAR) emissions based on the Subpart W data produces only about 25% of the emissions reductions as the TSD quarterly LDAR at over four times the cost per ton emissions reduction. These high costs suggest monitoring less frequently than annual could be warranted when baseline emissions are low.

Similar conclusions can be drawn from the storage data in Table 3. The alternative cost effectiveness values based on more current leak counts (from Subpart W surveys) and relatively high leaker emission factors from Subpart W result in cost effectiveness values ($/ton) several times higher than the TSD estimate. Although EPA has not defined a bright-line for an acceptable cost effectiveness value, *methane* cost effectiveness values of several thousand dollars per ton should not be considered cost effective. In addition, the Subpart W leaker emission factors result in a much higher emissions estimate (and reduction) than more recent information from a CARB report. If leak estimates based on CARB report correlation equations are used, the disparities would be orders of magnitude worse and methane $/ton values would exceed $100,000 per ton.

[2] If leak estimates based on the CARB correlation equations had been used, the emissions would be orders of magnitude lower and, thus, the cost effectiveness values would be orders of magnitude higher.

Table 2. Transmission Subpart OOOOa LDAR Cost-Effectiveness Estimates: TSD Estimates vs. Revised Estimates Based on CAPP and/or Subpart W Data.

Row	Model Plant Scenario	Annual Emissions Reductions (tpy)		Annual Cost ($/year)	Cost of Control - Single Pollutant[B] ($/ton)		Notes
		CH_4	VOC		CH_4	VOC	
	Quarterly OGI Monitoring						
1	TSD CE & TSD Baseline Emissions[B]	32.3	0.89	$27,369	$847	$30,606	80% CE (TSD estimate). Cost Data from TSD Tables 4-11 & 4-14.
2	90% CE & TSD Baseline Emissions	36.3	1.0	$27,369	$753	$27,335	90% CE (Refer to CAPP data discussion in Section 2).
3	TSD CE & Subpart W Data Baseline Emissions	7.5	0.21	$27,369	$3,642	$132,167	80% CE (TSD estimate). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
4	90% CE & Subpart W Data Baseline Emissions	8.5	0.23	$27,369	$3,237	$117,482	90% CE (Refer to CAPP data discussion in Section 2). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
	Annual OGI Monitoring						
5	TSD CE & TSD Baseline Emissions	16.2	0.45	$10,117	$626	$22,626	40% CE (TSD estimate). Cost Data from TSD Tables 4-9 & 4-12.
6	80% CE & TSD Baseline Emissions	32.3	0.90	$10,117	$313	$11,241	80% CE estimate (Refer to CAPP data in Section 2)
7	TSD CE & Subpart W Data Baseline Emissions	3.8	0.10	$10,117	$2,684	$96,626	40% CE (TSD estimate). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
8	80% CE & Subpart W Data Baseline Emissions	7.5	0.21	$10,117	$1,342	$48,313	80% CE estimate (Refer to CAPP data in Section 2). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).

A. Multi Pollutant Cost of Control values are 50% of the Single Pollutant Cost of Control values

B. Baseline emissions are pre-LDAR leak emissions (i.e., either TSD model plant or average transmission facility emissions based on Subpart W data)

Table 3. Storage Subpart OOOOa LDAR Cost-Effectiveness Estimates: TSD Estimates vs. Revised Estimates Based on CAPP and/or Subpart W Data.

Row	Model Plant Scenario	Annual Emissions Reductions (tpy)		Annual Cost ($/year)	Cost of Control - Single Pollutant[A] ($/ton)		Notes
		CH_4	VOC		CH_4	VOC	
	Quarterly OGI Monitoring						
9	TSD CE & TSD Baseline Emissions[B]	114.0	3.15	$42,093	$369	$13,348	80% CE (TSD estimate). Cost Data from TSD Tables 4-11 & 4-14.
10	90% CE & TSD Baseline Emissions	128.3	3.54	$42,093	$328	$11,878	90% CE (Refer to CAPP data discussion in Section 2).
11	TSD CE & Subpart W Data Baseline Emissions	24.8	0.69	$42,093	$1,696	$61,383	80% CE (TSD estimate). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
12	90% CE & Subpart W Data Baseline Emissions	28.2	0.78	$42,093	$1,495	$54,103	90% CE (Refer to CAPP data discussion in Section 2). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
	Annual OGI Monitoring						
13	TSD CE & TSD Baseline Emissions	57.0	1.58	$13,798	$242	$8,751	40% CE (TSD estimate). Cost Data from TSD Tables 4-9 & 4-12.
14	80% CE & TSD Baseline Emissions	114.0	3.16	$13,798	$121	$4,366	80% CE estimate (Refer to CAPP data in Section 2)
15	TSD CE & Subpart W Data Baseline Emissions	12.4	0.34	$13,798	$1,112	$40,115	40% CE (TSD estimate). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).
16	80% CE & Subpart W Data Baseline Emissions	14.1	0.39	$13,798	$980	$35,357	80% CE estimate (Refer to CAPP data in Section 2). Baseline emissions based on Subpart W leaker count and leaker EFs (Refer to Figure 5-1).

A. Multi Pollutant Cost of Control values are 50% of the Single Pollutant Cost of Control values

B. Baseline emissions are pre-LDAR leak emissions (i.e., either TSD model plant or average storage facility emissions based on Subpart W data)

Comparison of Subpart OOOOa Final Rule TSD Revisions – Draft Versus Final Versions

When EPA adopted the final Subpart OOOOa rule, EPA posted multiple versions of the final rule TSD in the docket: an April 2016 version[3] labeled "draft" and a May 2016 version[4] with no "draft" watermark. Section 2 of the INGAA White Paper cited text from the April 2016 draft TSD. The excerpt below shows the text from the April 2016 TSD in normal font, with additional text in the May 2016 TSD indicated by *underlined italics* font and deletions indicated by ~~strike-through~~ font. The updated text does not change the conclusions in INGAA's White Paper. Additional discussion is provided below.

> "From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, *based on our review of the studies*, monthly monitoring should achieve much higher emission reductions at this monitoring frequency.[5] *Based on the information in the studies and EPA's engineering judgement, the potential emission reduction percentages for the proposed rule were estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.*
>
> Data from the EPA (Leak) Protocol[6] document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. *Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies[7] were calculated using the data from the EPA Protocol document.* For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. *The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm.* The OGI camera is capable of viewing leaks at a 500 ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, *but closer to the 500 ppm level*.
>
> *A study performed by ICF[8] using data from Subpart W, EPA/GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA*

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[3] EPA-HQ-OAR-2010-0505-7642. "Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa," Draft version of final TSD, April 2016.

[4] EPA-HQ-OAR-2010-0505-7631. "Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa," May 2016.

[5] Note that April 2016 TSD text in this paragraph was not included in the June 8, 2018 INGAA white paper.

[6] EPA-453/R-95-017. "Protocol for Equipment Leak Emission Estimates," November 1995, *available at* https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf (emphasis added).

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

[8] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, revised May 2, 2016.

Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

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

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable."[9]

As noted below, the "new study" from ICF is simply another model-based estimate driven by inputs (i.e., assumptions) and is posted in the docket as PowerPoint slides rather than a transparent report.

The revised text in the final TSD does not change the conclusions in INGAA's White Paper regarding the impact of survey frequency and leak definition on LDAR control effectiveness:

(1) EPA's leak emissions reduction estimates are based on a LDAR control efficiency model with high uncertainty and biased by flawed and unrepresentative data and assumptions. These reduction estimates were not supported by actual measurements of gas leak emission reductions; and

(2) More reliable actual leak measurement data from implementation of a multi-year O&G systems DI&M program[10,11] indicates that about 75 – 80% reduction is achieved using annual monitoring.

For example, the following is a summary review of the three new references in the May 2016 TSD:

- Footnote 6, "Memorandum from Bradley Nelson…" simply documents calculation of the LDAR control efficiencies (CEs) listed in TSD Table 4-17.

[9] *See* Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

[10] EPA-HQ-OAR-2010-0505-4826. "Update of Fugitive Equipment Leak Emission Factors," Canadian Association of Petroleum Producers (CAPP), February 2014.

[11] "Management of Fugitive Emissions at Upstream Oil and Gas Facilities," Canadian Association of Petroleum Producers (CAPP), January 2007.

"(TSD) Table 4-17. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair"

Monitoring Frequency	Fugitive Percent Reduction (LDAR CE)		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Annual	42	68	40
Semi-annual	55	75	60
Quarterly	67	83	80

The INGAA White Paper lists and documents the numerous reasons these LDAR CEs have a large uncertainty and a low bias (e.g., the CEs are not measured values but rather EPA Leak Protocol LDAR CE model calculations based on out-of-date equipment and operations (i.e., 30 – 40 year-old) data from non-representative (i.e., non-oil and gas) process streams (i.e., synthetic organic chemical manufacturing industry (SOCMI) plants)).

- Footnote 7, "ICF International…" also presents *modeled* rather than *measured* LDAR CEs. The document in the Subpart OOOOa docket is simply a high-level PowerPoint presentation, and the calculations and underlying data are not presented. Further, the slides list a "Limitation of Analysis," which includes, "Model results or driven by data inputs," Limited time series data is available on the impact of different LDAR frequencies on reduction in leak frequencies in each subsequent survey," and, "Assumption in this study is based on best available data from Colorado." The Colorado data source is not clear but appears to be from the Jonah field in 2010 to 2015. This was a period of intense development of expanding oil and gas production in Colorado; thus, interpretation of such time series data from production may not be representative of typical transmission and storage operations.

  In sum, the 78% LDAR CE for quarterly leak monitoring that EPA cites from this document is a non-transparent, poorly supported, *modeled* estimate, and not based on *measured* CEs.

- The "sensitivity analysis" and LDAR CEs discussion associated with Footnote 8, "See Emission Reduction Comparison…" is simply the data discussed in the first two paragraphs of the above TSD text and the same data that EPA presents in TSD Table 4-17. This "sensitivity analysis" appears to be a circular discussion where the assumed CEs (i.e., 40, 60, and 80%) are compared to the data that are presented as the basis for the assumed CEs (i.e., the 10,000 ppm and 500 ppm LDAR CEs in TSD Table 4-17), and the ensuing agreement presented as independent support for the assumed CEs. A true "sensitivity analysis" would evaluate the impact of varying inputs to the EPA Leak Protocol LDAR CE model (e.g., Leak Occurrence Rate) on calculated/estimated CEs, and this would illuminate the high uncertainty in the LDAR CE model estimates.

In addition, the May 2016 TSD states:

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

The text, "*but closer to the 500 ppm level*" is text added to the May 2016 TSD. However, a review of the data in TSD Table 4-17 indicates that statement is only accurate for quarterly monitoring. The assumed OGI LDAR CEs for annual and semiannual monitoring frequencies are much closer to the 10,000 ppm LDAR CEs than to the 500 ppm LDAR CEs. For example, the CE estimate for an annual

survey and 500 ppm (the Subpart OOOOa leak definition), is 68% rather than 40%. If EPA believes LDAR CEs based on OGI monitoring are close to LDAR CEs for a Method 21 monitoring program with a 500 ppm leak definition (i.e., the Subpart OOOOa leak definition), then OGI monitoring LDAR CE should be close to 68% / 75% / 83% rather than 40% / 60% / 80%; this shows another flaw and contradiction regarding EPA's selective use of data to attempt to support the CEs in the proposed rule because the new supposition regarding OGI performance being closer to a 500 ppm level with Method 21 implies annual and semi-annual monitoring CE levels similar in magnitude to the 80% CE for quarterly monitoring originally assumed.

It also worth noting that EPA's claims about OGI leak detection sensitivity evolved, apparently in an attempt to support the earlier assumption of 40%, 60%, and 80% LDAR CEs. For example, the August 2015 TSD[12] for the proposed rule stated that 10,000 ppm leaks are near the limit of detection for OGI, based on "EPA's recent work with OGI systems . . . .":

> "The OGI instrument that is used to conduct monitoring surveys must be capable of imaging gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of ≥ 60 g/hr from a quarter inch diameter orifice. These criteria are based on the EPA's recent work with OGI systems indicating that fugitive emissions at a concentration of at least 10,000 ppm are generally detectible using OGI with proper monitoring and operating practices."

However, in the May 2016 TSD[13] EPA claimed that OGI can detect 500 ppm leaks – without providing any supporting data:

> "The OGI camera is capable of viewing leaks at a 500 ppm level."

The related TSD analysis and discussion is muddled and inconsistent, but implies EPA has a new understanding about OGI leak detection sensitivity and implications for the impact of survey frequency on LDAR performance. This statement appears to be an attempt to support the presumed 40%, 60%, and 80% LDAR CEs, but it was not supported with data or documentation, and, as noted above, implies estimated LDAR CEs of 68%, 75%, and 83%.

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[12] EPA-HQ-OAR-2010-0505-5120. Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR 60, subpart OOOOs, August 2015.

[13] EPA-HQ-OAR-2010-0505-7642. "Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa," May 2016.

Message

From: Thompson, Lisa [Thompson.Lisa@epa.gov]
Sent: 1/16/2018 7:22:58 PM
To: Eck, Janet [Eck.Janet@epa.gov]; Cozzie, David [Cozzie.David@epa.gov]
CC: Witosky, Matthew [Witosky.Matthew@epa.gov]
Subject: RE: Meeting request for next 30 days--Oil and Nat Gas

Edits in blue below.

From: Eck, Janet
Sent: Tuesday, January 16, 2018 1:58 PM
To: Cozzie, David <Cozzie.David@epa.gov>
Cc: Thompson, Lisa <Thompson.Lisa@epa.gov>; Witosky, Matthew <Witosky.Matthew@epa.gov>
Subject: FW: Meeting request for next 30 days--Oil and Nat Gas

Hi David, Pete South is asking for additional information concerning the meetings below. I have responded to some of his questions in red, but could use your help on the expanded purpose and in some areas I could not answer. Please make any changes to my responses you believe are necessary. Thanks.

From: South, Peter
Sent: Tuesday, January 16, 2018 12:24 PM
To: Mills, Kathy <Mills.Kathy@epa.gov>; Eck, Janet <Eck.Janet@epa.gov>
Subject: Meeting request for next 30 days--Oil and Nat Gas

I can schedule the first two meetings (for actions 1-2) with Peter T.

For actions 3-4, I'd like avoid confusing Emily and Josh. After taking a look at the meeting request forms (1 for Peter, 3 for Bill W and 2 for the Admin), I'd like to send the requests up with some explanation/context (minimal but something so people understand the difference btw the meetings). See my questions and requests for insert (very short). Can you provide inserts and send back?

Thanks and call me if you have questions or want to run through this verbally.

(1) ONG NSPS Amendments for ~~Proposed~~ Final Rule? (T3, SAN 5719.10)

Ex. 5 Deliberative Process (DP)

====

(2) ONG NESHAP—pre EG for Proposed Rule? Yes (T3, SAN 5732)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

====

(3) ONG NSPS Tech Reconsid for Proposed Rule, (T2, SAN 5719.8)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

====

(4) ONG NSPS Policy Reconsider for Proposed Rule (T1, SAN 6616)

Ex. 5 Deliberative Process (DP)

n?) Peter –

Ex. 5 Deliberative Process (DP)

Message

From: Miller, Elizabeth [Miller.Elizabeth@epa.gov]
Sent: 3/6/2018 1:35:23 PM
To: Davis, Alison [Davis.Alison@epa.gov]; Weatherhead, Darryl [Weatherhead.Darryl@epa.gov]
CC: Cozzie, David [Cozzie.David@epa.gov]; Keating, Martha [keating.martha@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]
Subject: RE: ACTION: POLITICO re methane rule amendment

Ex. 5 Deliberative Process (DP)

Thanks,
Beth

From: Davis, Alison
Sent: Tuesday, March 06, 2018 8:06 AM
To: Weatherhead, Darryl <Weatherhead.Darryl@epa.gov>; Miller, Elizabeth <Miller.Elizabeth@epa.gov>
Cc: Cozzie, David <Cozzie.David@epa.gov>; Keating, Martha <keating.martha@epa.gov>
Subject: Fwd: ACTION: POLITICO re methane rule amendment

Ex. 5 Deliberative Process (DP)

Sent from my iPhone

Begin forwarded message:

> **From:** "Jones, Enesta" <Jones.Enesta@epa.gov>
> **Date:** March 6, 2018 at 7:42:25 AM EST
> **To:** "DeLuca, Isabel" <DeLuca.Isabel@epa.gov>, "Bremer, Kristen" <Bremer.Kristen@epa.gov>, "Davis, Alison" <Davis.Alison@epa.gov>
> **Cc:** "Jones, Enesta" <Jones.Enesta@epa.gov>, "Daguillard, Robert" <Daguillard.Robert@epa.gov>
> **Subject: ACTION: POLITICO re methane rule amendment**
>
> Reflagging. Can we help here?
>
> On Mar 5, 2018, at 4:45 PM, Daguillard, Robert <Daguillard.Robert@epa.gov> wrote:

Ex. 5 Deliberative Process (DP)

Please advise.

Cheers, R.

Robert Daguillard
Office of Media Relations
U.S. Environmental Protection Agency
Washington, DC
+1 (202) 564-6618 (O)
+1 (202) 360-0476 (M)

++

A question on the first item here.

The final rules says the industry cost savings and foregone climate benefits of the emergency shutdown-related amendment could not be quantified "because of the unplanned nature of these events." But why couldn't EPA just average such events from the past five or ten years to get an estimate of those figures, while acknowledging the future is uncertain in these instances?

Thank you,
Alex Guillén
Politico

From: EPA Press Office [mailto:press=epa.gov@cmail19.com] **On Behalf Of** EPA Press Office
Sent: Thursday, March 01, 2018 4:45 PM
To: Alex Guillen <aguillen@politico.com>
Subject: EPA Takes Action to Address Oil and Gas Compliance Concerns, Saving At Least $14M in Regulatory Costs

U.S. ENVIRONMENTAL PROTECTION AGENCY
NEWS RELEASE
WWW.EPA.GOV/NEWSROOM

EPA Takes Action to Address Oil and Gas Compliance Concerns, Saving At Least $14 Million in Regulatory Costs

WASHINGTON (March 1, 2018) — In two actions, the U.S. Environmental Protection Agency (EPA) is taking steps to address significant and immediate compliance concerns for the oil and natural gas industry, reduce burdens on our state regulatory partners, and save millions of dollars in regulatory compliance costs.

EPA has finalized amendments for certain requirements contained within the 2016 oil and gas New Source Performance Standards (NSPS) and proposed to withdraw the control techniques guidelines (CTG) - an action that EPA estimates would save $14 to $16 million in regulatory compliance costs for the oil and gas industry from 2021-2035.

"The technical amendments to the 2016 oil and gas NSPS are meant to alleviate targeted regulatory compliance issues faced by affected sources," **said EPA Office of Air and Radiation Assistant Administrator Bill Wehrum**. "While this action addresses an immediate need, it does not deter the ongoing work at the Agency to assess the 2016 rule as a whole, including whether it is prudent or necessary to directly regulate methane."

"We believe the proposed withdrawal of the CTGs are necessary to provide regulatory certainty to one of the largest sectors of the American economy, and avoid unnecessary compliance costs to both covered entities and the states," **said Wehrum**.

Amendments to the 2016 New Source Performance Standards for the Oil and Gas Industry

EPA has amended two narrow provisions of the 2016 NSPS for the oil and natural gas industry to address aspects of the rule that pose significant and immediate compliance concerns. The amendments address two of the "fugitive emissions" requirements in the 2016 rule: a requirement that leaking components be repaired during unplanned or emergency shutdowns; and the monitoring survey requirements for well sites located on the Alaskan North Slope.

EPA took this final action in response to comments received on the June 2017 proposed stays of certain requirements in the rule and subsequent Notices of Data Availability (NODAs) issued in November 2017. EPA is continuing to evaluate comments the agency received on the proposed stays and NODAs.

To read the amendments to the 2016 rule, visit EPA's website at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#regactions

Proposal to withdraw the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry

In a separate action, EPA is proposing to withdraw the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry (Oil and Gas CTG) in its entirety. The Oil and Gas CTG provides recommendations for certain states and areas that are required to address smog-forming volatile organic compound (VOC) emissions from covered sources as part of their state implementation plans for meeting EPA's national standards for ground-level ozone.

The Oil and Gas CTG relied on data and conclusions that were used in the 2016 NSPS for the oil and gas industry. EPA is currently reconsidering certain aspects of the 2016 NSPS and intends to look broadly at the rule during the reconsideration process.

Because some recommendations in the Oil and Gas CTG are based on the 2016 NSPS, and others are based on the NSPS issued in 2012, EPA believes withdrawing the entire Oil and Gas CTG will be more efficient for states, which otherwise might be required to revise their implementation plans twice: once, to address recommendations that are tied to the 2012 NSPS, and potentially a second time after the reconsideration of the 2016 NSPS is complete.

EPA has analyzed costs that would be avoided if the Oil and Gas CTG were withdrawn. The Agency analyzed avoided costs assuming that, even if the Oil and Gas CTG were withdrawn, some states might need to obtain VOC emission reductions from existing oil and gas sources as part of their state implementation plans for meeting the ozone standard. Using this perspective, the agency estimates that the oil and gas industry would avoid costs of $1.2 million per year (3 percent discount rate) or $1.6 million per year (7 percent discount rate) under this perspective, totaling $14 or $16 million from 2021-2035 (using discount rates of 3 and 7 percent respectively).

The agency will take public comment on withdrawing the Oil and Gas CTG for 45 days after a notice is published in the Federal Register.

To read the notice of proposed withdrawal, visit EPA's website at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#ctg

<image002.png>

U.S. Environmental Protection Agency
1200 Pennsylvania Avenue Northwest
Washington, D.C. 20004

Unsubscribe

Appointment

From: Kime, Robin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=7EF7B76087A6475B80FC984AC2DD4497-RKIME]
Sent: 4/19/2017 9:08:41 PM
To: lfuller@ipaa.org; Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]; Bolen, Brittany [bolen.brittany@epa.gov]; Kime, Robin [Kime.Robin@epa.gov]; Samantha McDonald [SMcDonald@ipaa.org]; Schwab, Justin [schwab.justin@epa.gov]
CC: Inge, Carolyn [Inge.Carolyn@epa.gov]; Germann, Sandy [Germann.Sandy@epa.gov]; Irving, Verna [Irving.Verna@epa.gov]

Subject: Call with the Independent Petroleum Association of America: Prep for the Administrator's 5/1 Meeting: Please call the EPA Polycom Ex. 6 Personal Privacy (PP)
Location: 3513A

Start: 4/26/2017 7:00:00 PM
End: 4/26/2017 7:30:00 PM
Show Time As: Busy

Attendees:
Lee Fuller, Samantha McDonald, Susan Ginsberg of IPAA

Contact: Lee Fuller, lfuller@ipaa.org

From: Lee Fuller [mailto:lfuller@ipaa.org]
Sent: Friday, April 7, 2017 4:30 PM
To: Bolen, Brittany <bolen.brittany@epa.gov>
Subject: Regulatory Reform and Other Items

Brittany,

I read that one of your assignments is the regulatory reform task force. Consequently, I wanted to reach out on some issues of concern. I've attached an email that I sent to Ryan Jackson that raises several issues that we would like to discuss. (Separately, we are trying to arrange a meeting for Barry Russell, IPAA's President and CEO with Administrator Pruitt through Sydney Hupp.)

Obviously, events are moving quickly. I know that the Administration filed an abeyance petition on the Subpart OOOOa litigation today. There is an issue there that is related that I'd like to call to your attention. The Subpart OOOOa fugitive emissions program – with its costly Leak Detection and Repair (LDAR) requirements – is scheduled to take effect on June 3. It would be helpful if this requirement, at least, could be stayed while the Subpart OOOO and OOOOa requirements are being reconsidered since a different approach might be developed. I know there are other provisions that are already in effect that raise similar issues.

I also spoke with Dave Rostker from the SBA Advocacy office regarding LDAR in a small business context where the issues arises in both the Subpart OOOOa and VOC Control Techniques Guidelines context. He suggested reaching out to EPA as well.

Hopefully, we can discuss these issues soon given your schedule.

Thanks for your consideration,

Lee Fuller

From: Lee Fuller
Sent: Thursday, April 6, 2017 2:40 PM
To: Ryan Jackson (Jackson.Ryan@epa.gov) <Jackson.Ryan@epa.gov>
Subject: IPAA Issues at EPA; Possible Meeting

Ryan,

I'm reaching out to you but would be happy if you point me to a preferred contact person.

After the recent Energy Executive Order, IPAA would like to discuss a number of pending issues with EPA.

Barry Russell, IPAA's President and CEO, would like to meet with Administrator Pruitt to introduce himself and IPAA. Barry worked for EPA in the 1970s before coming to IPAA.

The issues that we'd like to discuss relate to several matters.

First, EPA's actions in response to the Energy EO with regard to the methane NSPS (Subparts OOOO and OOOOa) are most important to IPAA. While currently engaged in the litigation opposing the regulations, the pathway to reconsideration and possible revision is critical. IPAA wants to be involved as soon as possible and wants to offer its cooperation.

Second, IPAA strongly supports efforts to expand and enhance delegation of regulatory authority to states. We are looking for options to be helpful in identifying pathways, working with our state cooperating associations to encourage state actions and working with Congress if there are barriers that need to be addressed.

Additionally, following are several other items – mostly directly affecting independent oil and natural gas producers – that we would like to identify as issues that we would hope EPA could address:

1. Control Techniques Guidelines (CTG) – As a part of the Energy Executive Order, EPA is directed to reconsider the oil and natural gas methane New Source Performance Standard (NSPS) – Subparts OOOO and OOOOa. When the Obama Administration proposed the NSPS, it also proposed a CTG for existing sources of Volatile Organic Compounds (VOC) in Ozone nonattainment areas. The CTG was finalized in October 2016. It should be suspended or withdrawn until the NSPS issues are resolved and determinations can be made on the appropriateness of the technology being applied to existing sources. Otherwise, the CTG will be applicable in future State Implementation Plans (SIP).

2. RCRA Subtitle D Consent Decree – EPA agreed to a Consent Decree to settle litigation regarding mandatory duties under RCRA Subtitle D related to making determinations regarding the appropriateness of state oil and natural gas production wastes regulations. EPA has until March 2019 to respond but it should act quickly for two reasons. First, EPA's mandate to act does not require an extensive burden and the longer it takes to act, the more state programs appear to be viewed as inadequate. Second, the mandatory duties require action every three years. Action in 2017 would allow EPA to reconfirm its position in 2020 and establish a clear practice for the future.

3. Unconventional Oil and Gas (UOG) Extraction Effluent Limitations Guidelines (ELG) – EPA finalized UOG Extraction ELG for discharges to Publicly Owned Treatment Works (POTW) in June 2016. These ELG should be based on a technology standard – Best Available Technology Economically Achievable (BATEA). EPA concluded that all discharges to POTW should be prohibited based on the availability of underground injection wells and of recycling options. Neither of these are BATEA. EPA should not be making zero discharge

determinations based on its perception of other options. It should determine BATEA requirements. If the BATEA requirements are too expensive, it should be the dischargers' choice to use alternative approaches.

4. Clean Air Act Enforcement Tactics – Over the past several years, EPA's Enforcement tactics have been excessively aggressive. For example, in North Dakota where the state did not have delegation of the NSPS program for oil and natural gas production, EPA Enforcement initiated direct actions against producers with regard to its interpretation of Subpart OOOO requirements for storage vessels. This interpretation differed from those EPA technical staff had initially indicated. Using its enforcement power, EPA filed proposed penalties against a privately held producer that exceeded the value of its assets. The purpose was clear and predictable. EPA wanted to use its enforcement power to compel a limited asset company to enter into a consent agreement that would require actions that met Enforcement's interpretation of the regulation and to commit to additional actions that were beyond EPA Clean Air Act authority to require. Not only did EPA use a gap in state delegation to step over North Dakota in its zeal, but these types of enforcement tactics reflect poorly on EPA and the federal government and should be ended.

5. Ozone National Ambient Air Quality Standards (NAAQS) Revisions – The 2014 revision to the Ozone NAAQS should be reconsidered. Implementation of the 2008 revision to the Ozone NAAQS had yet to be implemented and evaluated when the 2014 revision was finalized. NAAQS attainment should be the target, not promulgating new, unachievable revisions. EPA's own data showed that the same areas it projected to fail to attain the 2008 NAAQS would fail to meet the 2014 revision. In those areas, the regulatory requirements would not change but the 2014 revision would bring new areas into nonattainment regulation. Even though EPA predicted those new areas would reach the 2014 NAAQS without additional local controls, those areas would be subject to new source permitting requirements that hamper their economic development. Where there is no compelling health benefit from a NAAQS revision – like the 2014 action – EPA should devote resources to attainment of the prior standard.

Thanks for considering this request. Please let me know how to proceed from here.

Lee Fuller

Message

From: Gunning, Paul [Gunning.Paul@epa.gov]
Sent: 3/16/2018 2:50:14 PM
To: Dunham, Sarah [Dunham.Sarah@epa.gov]
CC: Krieger, Jackie [Krieger.Jackie@epa.gov]
Subject: FW: Final OIG Report: "EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production"
Attachments: _epaoig_20180316-18-P-0129_cert.pdf

FYI...the OIG released their report.....

From: Vincent, Marc
Sent: Friday, March 16, 2018 10:39 AM
To: Gunning, Paul <Gunning.Paul@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; Price, Doris <Price.Doris@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>; Hopkins, Daniel <Hopkins.Daniel@epa.gov>
Cc: Marusiak, Eleanor <Marusiak.Eleanor@epa.gov>; Walters, Margaret <Walters.Margaret@epa.gov>; Hyde, Courtney <Hyde.Courtney@epa.gov>
Subject: FYI: Final OIG Report: "EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production"

Hi All,

Attached is the final OIG report, *EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production (Report No. 18-P-0129*). As you know, there are no recommendations for OAR.

Thank you all for your efforts throughout this engagement. Please share with others who may be interested and let me know if you have any questions.

Marc Vincent
Office of Program Management Operations
Office of Air and Radiation
(202)564-0876

From: OIG News
Sent: Friday, March 16, 2018 9:32 AM
To: Wehrum, Bill <Wehrum.Bill@epa.gov>
Cc: Pruitt, Scott <Pruitt.Scott@epa.gov>; Jackson, Ryan <jackson.ryan@epa.gov>; Darwin, Henry <darwin.henry@epa.gov>; Chmielewski, Kevin <chmielewski.kevin@epa.gov>; Bloom, David <Bloom.David@epa.gov>; Trent, Bobbie <Trent.Bobbie@epa.gov>; Anthony, Sherri <Anthony.Sherri@epa.gov>; Deane, Benita <Deane.Benita@epa.gov>; Osterman, Adam <Osterman.Adam@epa.gov>; Leopold, Matt <Leopold.Matt@epa.gov>; Lyons, Troy <lyons.troy@epa.gov>; Bowman, Liz <Bowman.Liz@epa.gov>; Shaw, Betsy <Shaw.Betsy@epa.gov>; Dunham, Sarah <Dunham.Sarah@epa.gov>; Benton, Michael <benton.michael@epa.gov>; Vincent, Marc <Vincent.Marc@epa.gov>; Marusiak, Eleanor <Marusiak.Eleanor@epa.gov>
Subject: OIG Report: "EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production"

Attached is the EPA Office of Inspector General (OIG) report, *EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production* (Report No. 18-P-0129). This report will be available to the public on the OIG's website at www.epa.gov/oig.

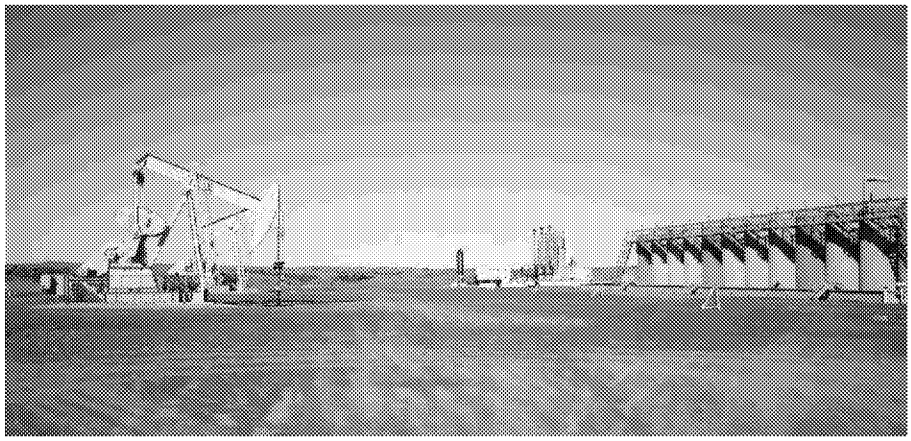
U.S. ENVIRONMENTAL PROTECTION AGENCY

OFFICE OF INSPECTOR GENERAL

Hotline Report:
Improving air quality

EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production

Report No. 18-P-0129 **March 16, 2018**



Report Contributors:

Richard Jones
Jim Hatfield
Erica Hauck
Alicia Mariscal

Abbreviations

CO_2e	Carbon Dioxide Equivalent
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
OIG	Office of Inspector General
UNFCCC	United Nations Framework Convention on Climate Change
UT-Austin	University of Texas-Austin

Cover photo: An oil production site in North Dakota. (EPA photo)

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U.S. Environmental Protection Agency
Office of Inspector General

18-P-0129
March 16, 2018

At a Glance

Why We Did This Review

The U.S. Environmental Protection Agency's (EPA's) Office of the Inspector General conducted this review in response to a hotline complaint alleging that the EPA used results from two flawed studies to estimate methane emissions and make policy decisions regarding oil and natural gas production. The complaint alleged that two methane emissions studies conducted by the University of Texas-Austin (UT-Austin), and sponsored by the Environmental Defense Fund (EDF), were flawed due to a malfunction in one of the measurement devices called a Hi Flow Sampler.

Our objectives were to determine (1) how the EPA estimates methane emissions from oil and natural gas production, including whether the EPA used results from the two EDF/UT-Austin studies to estimate emissions; and (2) whether concerns about technical or other problems with the studies were identified or brought to the EPA's attention, and how the EPA addressed and resolved those concerns.

This report addresses the following:

- *Improving air quality.*

Send all inquiries to our public affairs office at (202) 566-2391 or visit www.epa.gov/oig.

Listing of OIG reports.

EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production

What We Found

Methane is a potent greenhouse gas emitted from natural and industrial sources, including oil and natural gas production facilities.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks (Greenhouse Gas Inventory) reflects the EPA's official nationwide estimate for greenhouse gas emissions from all man-made sources, including those from oil and natural gas production. The inventory is developed using a variety of data sources and emission estimation methodologies. One source of data for the inventory is emissions and activity data reported to the EPA under its Greenhouse Gas Reporting Program. This reporting program requires large emission sources and fuel suppliers to calculate and report their greenhouse gas emissions data to the EPA.

The EPA used its Greenhouse Gas Inventory development process to consider information related to the EDF/UT-Austin studies and the Hi Flow Sampler. In memorandums issued in 2015 and 2016, inventory staff requested expert and public feedback on specific aspects of the EDF/UT-Austin studies, how data could potentially be used for the inventory, and potential problems with the Hi Flow Sampler.

The EPA ultimately did not make any methodological revisions to the Greenhouse Gas Inventory or to the Greenhouse Gas Reporting Program based on the EDF/UT-Austin studies, and data from the studies have not been incorporated into the inventory. In addition, the EPA did not use any data from the EDF/UT-Austin studies to set the final 2016 New Source Performance Standards to limit methane emissions from the oil and natural gas industry.

We make no recommendations.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

THE INSPECTOR GENERAL

March 16, 2018

MEMORANDUM

SUBJECT: EPA Did Not Use Allegedly Flawed Studies to Estimate Methane Emissions or Set New Source Performance Standards for Oil and Natural Gas Production
Report No. 18-P-0129

FROM: Arthur J. Elkins Jr.

TO: Bill Wehrum, Assistant Administrator
Office of Air and Radiation

This is our report on the subject evaluation conducted by the Office of Inspector General (OIG) of the U.S. Environmental Protection Agency (EPA). The project number for this evaluation was OPE-FY17-0017. This report represents the opinion of the OIG and does not necessarily represent the final EPA position.

This report contains no recommendations, and you are not required to respond to this report. However, if you submit a response, it will be posted on the OIG's public website, along with our memorandum commenting on your response. Your response should be provided as an Adobe PDF file that complies with the accessibility requirements of Section 508 of the Rehabilitation Act of 1973, as amended. The final response should not contain data that you do not want to be released to the public; if your response contains such data, you should identify the data for redaction or removal along with corresponding justification.

We will post this report to our website at www.epa.gov/oig.

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Purpose

In response to a hotline complaint, the U.S. Environmental Protection Agency's (EPA's) Office of Inspector General (OIG) conducted this review to determine the following:

(1) How the EPA estimates methane emissions from the oil and natural gas production sector, including the extent to which the EPA has used results from the 2013 and 2014 emission studies conducted jointly by the Environmental Defense Fund (EDF) and the University of Texas-Austin (UT-Austin) to estimate those emissions.[1]

(2) Whether concerns about technical or other problems with the studies were identified or brought to the EPA's attention, and how the EPA addressed and resolved those concerns.

Background

In 2016, the OIG received a hotline complaint alleging that two methane emission studies conducted by EDF/UT-Austin in 2013 and 2014 were flawed, and that the EPA had made greenhouse gas policy and emission estimation decisions based on the studies. The complaint alleged that the results of the studies were flawed because one of the sampling devices (called a Hi Flow Sampler) used to measure emissions for some of the sources malfunctioned, particularly when measuring gas streams that contained high amounts of hydrocarbons in addition to methane.

The complaint alleged that the malfunction caused the EDF/UT-Austin studies to underestimate emissions. In addition, the complaint alleged that the Hi Flow Sampler can malfunction when measuring high methane gas streams, such as those found in the transmission segment of the industry. The Hi Flow Sampler is a high-volume sampler, which is a type of measurement device approved by the EPA for measuring and reporting methane emissions from certain sources in the transmission and processing segments, but not the production segment.

Methane Emissions From the Oil and Natural Gas Production Sector

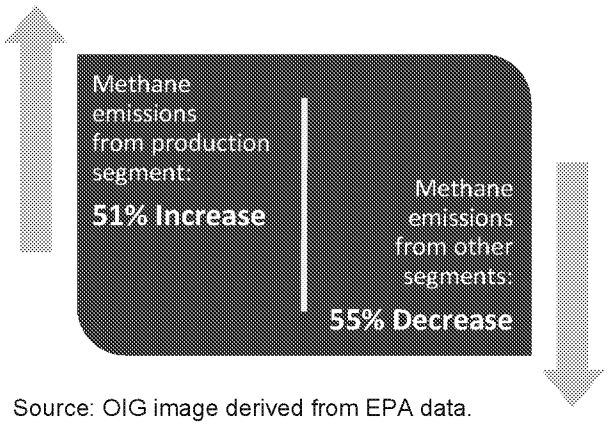
Methane is the second-most emitted greenhouse gas and has a heat trapping potential of up to 25 times that of carbon dioxide. According to the EPA, about one-third of U.S. methane emissions come from natural gas and petroleum

[1] Allen, D.T., V.M. Torres, J. Thomas, D. Sullivan, M. Harrison, A. Hendler et al., 2013. *Measurements of Methane Emissions at Natural Gas Production Sites in the United States*. Proc. Natl. Acad. Sci. USA 110:17768–17773. Allen, D.T., A. Pacsi, D. Sullivan, D. Zavala-Araiza, M. Harrison, K. Keen et al., 2014. *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*. Environ. Sci. Technol. 49:633–640.

ED_002880A_00043163-00006

systems.[2] While methane emissions from other segments of the natural gas industry (e.g., distribution, transmission and storage, and processing) decreased between 1990 and 2015, the EPA estimates that emissions from the production segment increased by 51 percent (Figure 1). Oil and natural gas production in the U.S. is rapidly expanding due, in part, to exploration of large unconventional gas reserves. The Energy Information Administration at the U.S. Department of Energy projects that natural gas production in the U.S. will increase by 45 percent between 2013 and 2040.

Figure 1: EPA estimated methane emissions trends comparison for the natural gas industry (1990-2015)



Source: OIG image derived from EPA data.

The process of oil and natural gas production consists of wells used to extract oil and natural gas from underground formations. Emissions are released from the wells, and from well-site gas treatment equipment such as dehydrators and separators. In total, the Energy Information Administration estimates there were over 1 million producing oil and natural gas wells nationwide in 2016.

Published research on estimates of methane emissions from natural gas production have varied widely, and a great amount of uncertainty exists in estimating these emissions. For example, studies using top-down approaches, such as ground monitors or aircraft that measure ambient concentrations of methane, indicate that traditional approaches used to develop emission inventories may be significantly underestimating emissions.

Environmental Defense Fund Studies on Emissions From Oil and Natural Gas Production

Given the uncertainties with methane emission estimation and measurement in the natural gas industry, the EDF collaborated with about 100 research institutions, universities and companies to conduct a series of 16 emission studies covering all segments of the industry. Two of these studies focused on the production segment. Dr. David T. Allen, former chair of the EPA's Science Advisory Board, led both studies at UT–Austin.

[2] Petroleum systems, as defined by the EPA, include oil production, as well as oil transportation and petroleum refining. Approximately 98 percent of total methane emissions from petroleum systems come from oil production.

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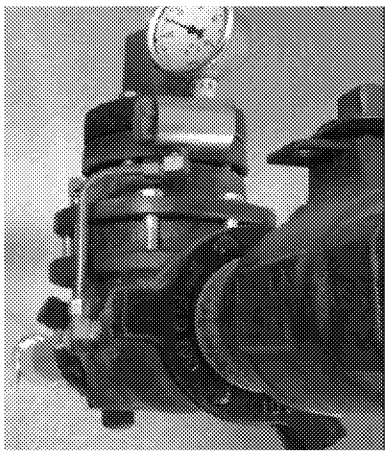
The first production segment study, which was published in 2013,[3] involved direct measurements of well-site processes and equipment using several different methods, including the Hi Flow Sampler device. The second production segment study, which was published in 2014,[4] involved direct measurements of pneumatic controllers used to regulate routine functions at well sites. This study also used a Hi Flow Sampler to measure emissions for a small percentage of the controllers in the study.

Hi Flow Sampler

The Hi Flow Sampler is a portable instrument designed to capture and quantify leaks at natural gas transmission, storage and compressor facilities, where gas streams are generally comprised almost entirely of methane. Under Subpart W of the EPA's Greenhouse Gas Reporting Program, high-volume samplers, such as the Hi Flow Sampler, are approved for directly measuring methane emissions from three sources (storage tanks, centrifugal compressor venting, and reciprocating compressor venting) in the processing and transmission segments. Direct measurement using these devices is one option, among several, that facilities can use to estimate and report emissions for these sources.



A pneumatic controller at a production site in Utah. (EPA photo)

Use of high-volume samplers is not an approved method for any source in the production segment. Further, the manufacturer of the Hi Flow Sampler did not intend for it to be used at production facilities where gas streams can include a high amount of non-methane hydrocarbons. However, researchers have begun using the Hi Flow Sampler device for studies on the production segment, such as the EDF/UT-Austin studies, because the device is the most convenient and cost-effective way to capture and quantify an entire leak.

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[3] Allen, D.T., V.M. Torres, J. Thomas, D. Sullivan, M. Harrison, A. Hendler et al., 2013. *Measurements of Methane Emissions at Natural Gas Production Sites in the United States*. Proc. Natl. Acad. Sci. USA 110:17768–17773.
[4] Allen, D.T., A. Pacsi, D. Sullivan, D. Zavala-Araiza, M. Harrison, K. Keen et al., 2014. *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*. Environ. Sci. Technol. 49:633–640.

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EPA's New Source Performance Standards for Oil and Gas Production

In 2016, the EPA updated its New Source Performance Standards[5] for the oil and natural gas industry to reduce methane emissions. These were the first standards to specifically regulate methane emissions from the industry. The prior standards issued in 2012 were expected to result in methane reductions as a co-benefit of reducing other pollutants, but they did not set specific standards for methane emissions. The 2016 standards have built on the 2012 standards to set specific standards to reduce methane emissions from the oil and natural gas industry, including production sources such as well completions, pneumatic controllers, and fugitive emissions.

Responsible Office

The EPA's Office of Air and Radiation, Office of Atmospheric Programs, is responsible for estimating methane emissions from oil and natural gas production.

Scope and Methodology

We conducted our review from July 2017 to January 2018. We conducted this performance audit in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our objectives.

To address our objectives, we reviewed regulations, policies, procedures and guidance related to evaluating methane emissions from oil and natural gas production. We placed particular emphasis on criteria and quality assurance processes for greenhouse gas reporting, the development of the Inventory of U.S. Greenhouse Gas Emissions and Sinks, and procedures for revising methods to estimate emissions in the inventory and under Subpart W of the Greenhouse Gas Reporting Program.

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[5] Section 111 of the Clean Air Act authorizes the EPA to develop technology-based air emission standards for specific categories of stationary sources. These standards apply to newly constructed, modified and reconstructed sources, and are referred to as the New Source Performance Standards. The EPA can delegate implementation and enforcement of the standards to the states. However, even when delegated to the states, the EPA retains authority to enforce the standards.

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We reviewed the 2013 and 2014 EDF/UT-Austin studies, as well as critiques of the studies published by engineer Touché Howard.[6] We also reviewed published articles by Mr. Howard regarding the potential failure of the Hi Flow Sampler under certain circumstances. We interviewed Dr. David Allen and the researcher who oversaw the measurements for the studies, Mr. Howard, and representatives from the manufacturer and distributor of the Hi Flow Sampler.

To determine whether the EPA used data from the 2013 and 2014 EDF/UT-Austin studies to develop methane emissions estimates, we reviewed recent Greenhouse Gas Inventory reports and supporting documentation, including memorandums that inventory staff issued soliciting feedback on new data and methods for the inventory. In addition, we reviewed supporting documentation for the EPA's 2016 oil and natural gas New Source Performance Standards. We also reviewed internal EPA communications about the 2013 and 2014 studies, and the potential problems with the Hi Flow Sampler.

We interviewed staff from two Office of Air and Radiation offices: the Office of Atmospheric Programs, and the Office of Air Quality Planning and Standards. Staff from the EPA's Office of Research and Development and EPA Region 8 were also interviewed.

We also met with representatives from the Independent Petroleum Association of America (IPAA) after receiving written concerns from that organization about the EPA's development of emission estimates. The IPAA expressed concerns that the EPA was overestimating methane emissions in its Greenhouse Gas Inventory, and had overestimated emissions for certain types of facilities when developing the 2016 New Source Performance Standards for oil and natural gas production sites. Since the EPA plans to reconsider these standards for oil and natural gas production, we did not review IPAA's concern about the New Source Performance Standards.

We conducted limited work to assess the topic areas of IPAA's concerns about overestimation of methane emissions in the Greenhouse Gas Inventory,[7] since those concerns were not within our scope. Based on our review of inventory documents, we concluded that the EPA followed its normal development process in relation to those topic areas. As a result, we did not review them further.

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[6] Touché Howard is an engineer who developed a high-flow sampling device in the early 1990s. In the early 2000s, Mr. Howard's concept was commercialized by a private company with different hardware and components and named the Hi Flow Sampler.

[7] IPAA's concerns involved the revised methods that the EPA used in the 1990–2014 Greenhouse Gas Inventory to (1) extrapolate, or scale, data from facilities that reported to the Greenhouse Gas Reporting Program to facilities that are not required to report to the program; and (2) estimate the number of gathering and boosting facilities and associated emissions.

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Results

The EPA has two established programs that estimate U.S. greenhouse gas emissions, including methane emissions from oil and natural gas production:

- The Greenhouse Gas Reporting Program.
- The Inventory of U.S. Greenhouse Gas Emissions and Sinks.

We found that the EPA used the Greenhouse Gas Inventory development process to consider and solicit feedback on the EDF/UT-Austin studies and the Hi Flow Sampler. However, the EPA has not used data or conclusions from the studies to revise its methane emission estimates for oil and gas production, or to set New Source Performance Standards to limit methane emissions from the industry.

Greenhouse Gas Reporting Program

The 2008 Consolidated Appropriations Act required the EPA to develop a rule that mandates the reporting of greenhouse gases. The implementation of this rule is referred to as the Greenhouse Gas Reporting Program, which requires large emission sources and fuel suppliers to report their greenhouse gas emissions data to the EPA. The program has a reporting threshold of 25,000 metric tons of carbon dioxide equivalent (CO_2e) per year, so only those oil and natural gas production facilities exceeding that threshold are required to report emissions under the program.[8]

The Greenhouse Gas Reporting Program does not reflect all emissions from the industry. Subpart W of the program contains specific reporting requirements for oil and natural gas production sources, including methods to be used by facilities to estimate emissions from specific sources. For production, many of the methods are engineering calculations that incorporate "emission factors."[9] Figure 2 provides an overview of the petroleum and natural gas industry, and the operations covered by the Greenhouse Gas Reporting Program.

[8] In general, a "facility" for purposes of the Greenhouse Gas Reporting Program means all co-located emission sources that are commonly owned or operated. However, the program has developed a specialized facility definition for certain segments, including onshore production. For onshore production, a "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

[9] The EPA defines an emission factor as a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant.

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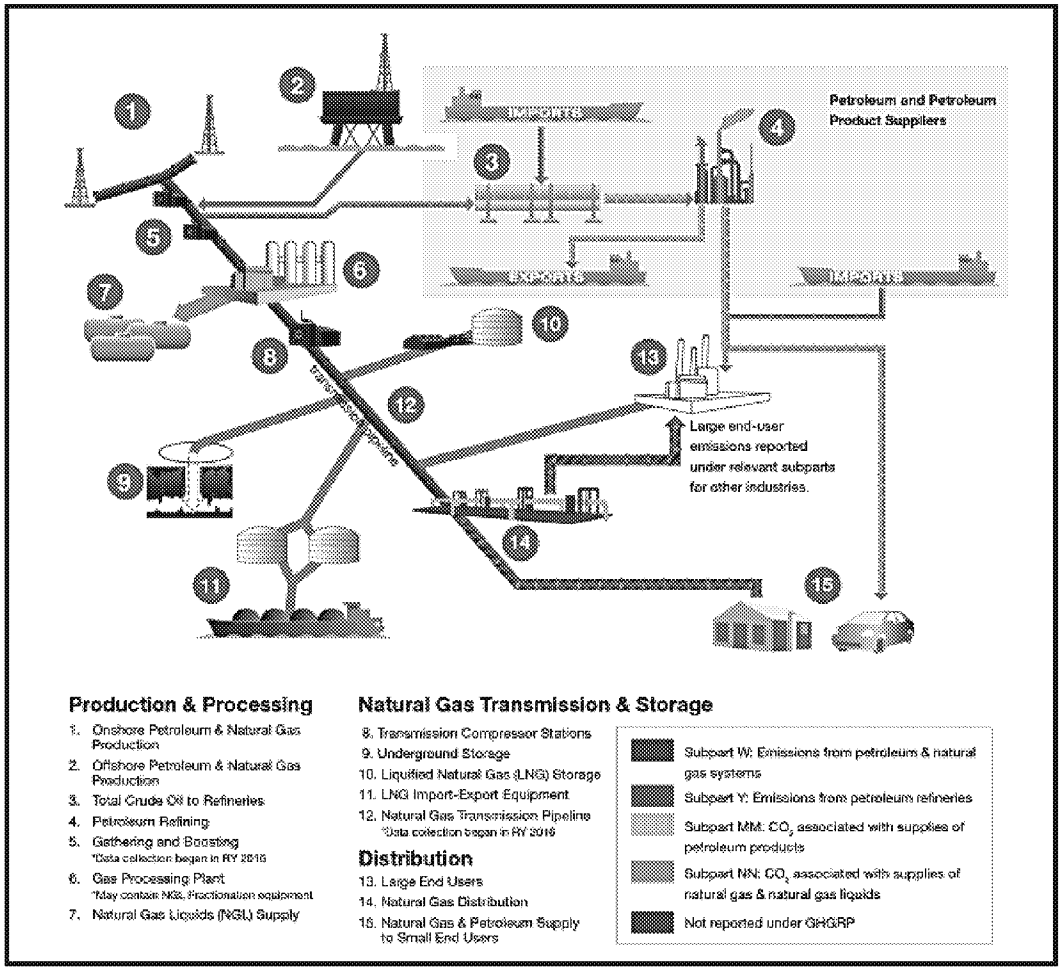
Figure 2: Oil and natural gas operations covered by the Greenhouse Gas Reporting Program



Source: The EPA.

Greenhouse Gas Inventory

The Greenhouse Gas Inventory is an annual report that provides a comprehensive accounting of total greenhouse gas emissions for all man-made sources in the U.S., including oil and natural gas production. The inventory also calculates carbon dioxide emissions that are removed from the atmosphere by "sinks" (i.e., through the uptake of carbon and storage in forests, vegetation and soils).

The EPA compiles the Greenhouse Gas Inventory on an annual basis to meet commitments under the United Nations Framework Convention on Climate Change (UNFCCC). The estimates in the inventory are calculated consistent with recommendations in the *2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories*, which allows the inventory to be compared to those developed by other UNFCCC parties. The EPA collaborates with other U.S. government agencies, academic institutions, industry

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associations, consultants and environmental organizations in preparing the inventory.

The Greenhouse Gas Inventory represents the EPA's official nationwide estimate for oil and natural gas production methane emissions. The inventory provides an estimate of emissions for the entire universe of U.S. sources for every year since 1990. The most recent inventory was published in 2017 and covers 1990–2015. For 2015, the Greenhouse Gas Inventory estimated that oil and natural gas production emitted 145.6 million metric tons CO_2e of methane. This accounted for 22.2 percent of all methane emissions and 2.5 percent of all greenhouse gas emissions in the inventory.

Greenhouse Gas Inventory Development Process

The EPA updates the Greenhouse Gas Inventory each year. For most oil and natural gas production sources, the EPA develops estimates based on the number of wells for a given year, as reported in an industry database called DrillingInfo.

The EPA generally develops estimates for specific types of equipment (e.g., separators, pneumatic controllers) by determining the average number of that type of equipment located at a well. This is referred to as activity data or an activity factor. The per-well activity factors are applied to national well counts to calculate total national activity data. The EPA then applies an emission factor to the national activity data to estimate emissions. The Greenhouse Gas Inventory draws from a number of information sources for emission factors and activity data, including a 1996 study conducted by the EPA and the Gas Research Institute, other federal agencies, and industry research. As data from the Greenhouse Gas Reporting Program have become available in recent years, that data have been incorporated into the inventory as appropriate.

In accordance with the 2006 IPCC guidelines, the EPA attempts each year to improve the analyses in the Greenhouse Gas Inventory through better data and methods. In addition, inventory staff revise production emission estimates as new data become available. To do so, Greenhouse Gas Inventory staff follow a process for updating new versions of the inventory, which involves evaluating newly available or updated data, and seeking expert and public feedback on proposed methodological revisions.

Each year, inventory staff identify new or updated data made available through the Greenhouse Gas Reporting Program, external studies and updates to existing external information sources, such as DrillingInfo, and assess whether information or methods in the inventory should be revised. Inventory staff request feedback from industry experts and the public on potential new data sources and methods, through memorandums issued to a listserv of experts and posted on the EPA's website. Before finalizing the inventory report, the EPA also seeks public comment on the entire draft inventory by publishing it in the Federal Register.

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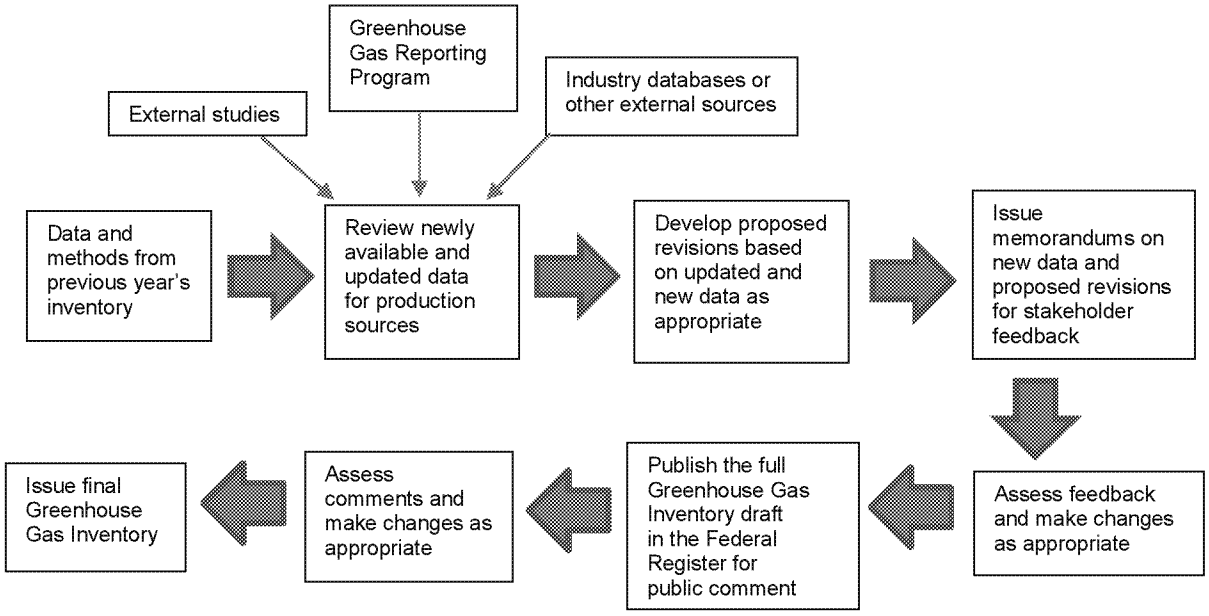
Figure 3 depicts the process used to incorporate new data and methodological changes into the Greenhouse Gas Inventory.

Figure 3: Process for considering new data and revising the Greenhouse Gas Inventory



Source: OIG analysis based on Greenhouse Gas Inventory documentation.

EPA Considered Information Related to the EDF/UT-Austin Studies as Part of Its Inventory Development Process

As part of its efforts to review newly available data for oil and natural gas production sources, the EPA invited the EDF/UT-Austin study teams to present the results of their 2013 and 2014 studies. Presentations for the two studies occurred in September 2013 and December 2014, respectively.

Also in 2014, staff from the EPA's Office of Atmospheric Programs received a briefing from the agency's Office of Research and Development staff, who had experience using a Hi Flow Sampler similar to the one used in the EDF/UT-Austin studies. Office of Research and Development staff had observed problems with the Hi Flow Sampler in 2011, when using the device in a study to measure leaks at condensate tanks at oil and gas production facilities.[10] Emissions from those tanks were high in hydrocarbons, and Office of Research and Development staff theorized that the hydrocarbons overwhelmed the Hi Flow Sampler's sensors, causing the device to malfunction.

[10] This study used the Hi Flow Sampler to measure emissions from multiple sources at oil and natural gas production facilities. The research team observed problems with the device only when measuring large emissions from condensate tanks. In 2012, an EPA contractor presented a paper on the experiences with the Hi Flow Sampler in this study at an Air and Waste Management Association meeting.

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Office of Research and Development staff told us that during the 2014 briefing to the Office of Atmospheric Programs, they notified them about forthcoming concerns from Mr. Howard about the Hi Flow Sampler.

In 2015, a journal article and formal comments by Mr. Howard were published critiquing the measurements made with the Hi Flow Sampler in the EDF/UT-Austin studies. He also expressed his concerns to EPA staff via email. In February 2016, Mr. Howard formally presented his concerns to EPA staff and others, including members of the press, via a teleconference/internet presentation.

The EPA formally requested comment on the EDF/UT-Austin studies and the Hi Flow Sampler in memorandums for the 1990–2013 and 1990–2014 Greenhouse Gas Inventories. Specifically, in memorandums issued in 2015 and 2016, inventory staff requested stakeholder feedback on the following:

- Specific aspects of the EDF/UT-Austin studies related to pneumatic controllers and how data could potentially be used for the Greenhouse Gas Inventory.

- Whether potential problems with Hi Flow Sampler measurements may have affected new studies of emissions from transmission and distribution segments, and whether methods exist for recalculating some of the data points to correct for potential Hi Flow Sampler problems.

In the years since publication of the EDF/UT-Austin studies, EPA staff have also attended events where Mr. Howard presented his concerns, and used the occasions to engage stakeholders on potential problems with the Hi Flow Sampler.

Extent and Significance of Device Malfunction in Production Measurements Have Not Been Established

While there is evidence that some Hi Flow Samplers have failed under certain conditions, the extent and significance of these failures have not been established in studies. Researchers in the EPA's Office of Research and Development encountered a malfunction when using the device to measure tank emissions in the production sector in 2011, and the researcher who oversaw the measurements for the EDF/UT-Austin production segment studies told us Mr. Howard is correct that the Hi Flow Sampler can fail under certain circumstances. However, the researcher does not believe these failures occur as frequently as Mr. Howard claims.

Further, Dr. Allen, the lead researcher of the EDF/UT-Austin production segment studies, said he has seen no evidence of the sensor failures described by Mr. Howard, though one of his Hi Flow Samplers shut down during field testing that was conducted after the 2013 study. We found that there has not been sufficient

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testing to determine specific conditions in which the device might malfunction, how prevalent the problem might be (i.e., are only some devices faulty or is it a systemic problem), or whether there are operational best practices that could mitigate the problem.

To date, field testing has been conducted with only several devices, and results have been inconclusive. The researcher who oversaw the measurements for the 2013 and 2014 EDF/UT-Austin studies views Mr. Howard's concerns as a valuable part of the scientific process for assessing measurements taken with the Hi Flow Sampler. Use of the Hi Flow Sampler to measure gas streams for which it was not specifically designed led the manufacturer of the Hi Flow Sampler to update its user manual to caution against the device being used to measure high hydrocarbon gas streams.

Claim That the Device Can Malfunction in Other Segments Is Unproven

In two journal articles, Mr. Howard concluded that the Hi Flow Sampler can also malfunction when measuring gas streams with very high methane content and low hydrocarbons, such as those found in the transmission and processing segments where the device is approved for measurement of some sources under Subpart W. Mr. Howard based his conclusions on analyses of measurements taken in other studies, including the 2013 EDF/UT-Austin study. Mr. Howard did not conduct any direct testing where he encountered and/or documented a failure when measuring very high methane content gas streams.

EPA staff we spoke with are not aware of any data that indicate the Hi Flow Sampler malfunctions in high methane content gas streams. Thus, the EPA has not made any revisions to the approved methods for high-volume samplers (including the Hi Flow Sampler) in the Greenhouse Gas Reporting Program for certain sources in the transmission and processing segments. We believe this is appropriate for the following reasons:

- Malfunction of the device in these segments is unproven.
- The EPA approved these methods for use as intended by the manufacturer.
- EPA staff are aware of the concerns and are tracking the issue.
- The Greenhouse Gas Reporting Program is not intended to assess compliance with any particular standard, and thus some degree of uncertainty is tolerable.
- EPA staff sought feedback on the issue through Greenhouse Gas Inventory memorandums issued in 2015 and 2016.

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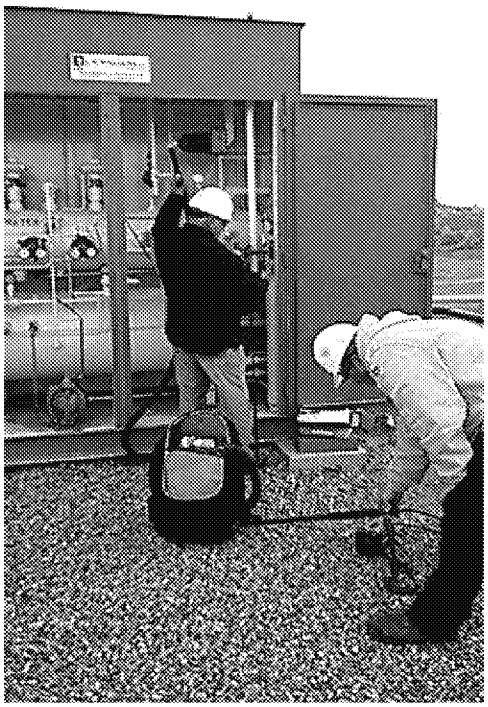
EPA Has Not Used EDF/UT-Austin Studies for Official Emission Estimation or Rulemaking Purposes

As stated above, Greenhouse Gas Inventory staff considered and requested comment on various aspects of the EDF/UT-Austin studies. However, the EPA ultimately did not make any methodological revisions to the inventory based on the EDF/UT-Austin studies, and data from the studies have not been incorporated into the inventory. The EPA also has not made any revisions to the emission factors or calculations for production sources in Subpart W of the Greenhouse Gas Reporting Program based on these studies. In addition, while the EPA consulted the studies, along with a number of other information sources during the rulemaking process to set New Source Performance Standards to limit methane emissions from the oil and natural gas industry, the EPA did not use any data from the studies to set the final standards issued in 2016.

EPA Researchers Developed an Augmented Protocol for Hi Flow Sampler Use

After experiencing Hi Flow Sampler malfunctioning in its earlier research, the EPA's Office of Research and Development developed an augmented (work-around) approach for using the device for field measurements. In a 2015 study at production sites, staff from EPA Region 8 and the Office of Research and Development measured and analyzed the hydrocarbon content of the gas stream with a probe as an additional quality assurance step for each measurement it took with the Hi Flow Sampler. In addition, the Office of Research and Development is currently attempting to develop a new high-volume sampler for internal agency use.



Researchers using a Hi Flow Sampler, and a hand-held probe for quality assurance, at a production site in Utah. (EPA photo)

In October 2017, Office of Research and Development staff, in conjunction with staff from EPA Region 8, were awarded funding of $100,000 through the EPA Regional Applied Research Effort program to develop and test a new high-volume sampler prototype.[11] The main impetus for this development is that the manufacturer is no longer producing the Hi Flow Sampler, and there are currently

[11] Office of Research and Development staff told us they may receive an additional $25,000 in funding for the project in fiscal year 2019.

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no high-volume samplers commercially available, although an Office of Research and Development researcher told us they also hope to improve on the design of the Hi Flow Sampler to eliminate any potential malfunction problems. The researcher told us this undertaking is complicated by safety considerations, and they are determining whether additional funding will be needed to complete the project.

Conclusion

EPA staff were aware of potential concerns raised about the EDF/UT-Austin studies and used the agency's internal review processes to evaluate data and solicit stakeholder feedback. Specifically, the EPA used its annual Greenhouse Gas Inventory development process to consider data from the studies, and sought stakeholder feedback on aspects of the studies through memorandums when developing the 1990–2013 and 1990–2014 inventories. The EPA ultimately did not make any changes to the inventory or to the Greenhouse Gas Reporting Program based on data from the studies. In addition, the EPA did not use data from the studies to set the 2016 New Source Performance Standards to limit methane emissions from the oil and natural gas industry.

The EPA also used the Greenhouse Gas Inventory development process to solicit expert feedback on the Hi Flow Sampler. High-volume samplers, such as the Hi Flow Sampler, remain approved reporting tools under the Greenhouse Gas Reporting Program for certain large sources in the oil and natural gas transmission and processing segments. We did not find any conclusive evidence indicating device malfunctions in those segments.

Agency Response and OIG Evaluation

The agency provided technical comments on the draft version of this report. We have made changes as appropriate based on those comments.

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Message

From: Perez, Idalia [Perez.Idalia@epa.gov]
Sent: 10/26/2017 10:58:47 PM
To: Air Program Managers - Regions [Air_Program_Managers_Regions@epa.gov]; ORC - Regional Air Managers [ORC-Regional_Air_Managers@epa.gov]; Air Division Directors and Deputies [Air_Division_Directors_and_Deputies@epa.gov]
CC: DeMocker, Jim [DeMocker.Jim@epa.gov]; Rapp, Steve [Rapp.Steve@epa.gov]; Saltman, Tamara [Saltman.Tamara@epa.gov]; Shaw, Betsy [Shaw.Betsy@epa.gov]; Shoaff, John [Shoaff.John@epa.gov]; Benner, Tim [Benner.Tim@epa.gov]; Dunham, Sarah [Dunham.Sarah@epa.gov]; Lewis, Josh [Lewis.Josh@epa.gov]; Cyran, Carissa [Cyran.Carissa@epa.gov]; Salgado, Omayra [Salgado.Omayra@epa.gov]; Hyde, Courtney [Hyde.Courtney@epa.gov]; Millett, John [Millett.John@epa.gov]; Schultz, Laurel [Schultz.Laurel@epa.gov]
Subject: OAR Lead Region News, Updates & Reminders: 10-26-17
Attachments: eo-13783-final-report-10-25-2017.pdf

Sending updates a day early because I will be out of the office tomorrow. Have a nice weekend! -Idalia

Updates

- **Report in Response to EO 13783:** EPA released a "Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783" (attached). In this report, EPA identified four key initiatives that it believes will further the goal of reducing unnecessary burdens on the development and use of domestic energy resources. These initiatives include: (1) comprehensive New Source Review reform, (2) National Ambient Air Quality Standards (NAAQS) reform, (3) robust evaluations of the employment effects of EPA regulations, and (4) a sector-based outreach program. To address these areas, the report states that:
    - The Administrator intends to convene an NSR Reform Task Force, details of which will be announced in a forthcoming agency memorandum.
    - EPA plans to work to streamline SIP approvals through a nationally consistent process that includes setting performance targets, and better monitoring progress on SIP reviews. EPA further plans to work to eliminate the SIP backlog.
    - EPA intends to conduct continuing evaluations of potential losses or shifts of employment that may result from implementation of these statutes consistent with various statutes.
    - EPA recently announced its *Smart Sectors* program to re-examine how it engages with industry to reduce unnecessary regulatory burdens, improve regulatory forecasting and predictability, and improve the ability of both EPA and industry to conduct long-term regulatory planning.
- **SmartWay Excellence Award:** EPA's SmartWay Transport Partnership is a market-driven initiative that empowers businesses to move goods in the cleanest, most energy-efficient way possible to protect public health by reducing harmful air emissions. The EPA announced the 2017 winners of the coveted SmartWay® Excellence Award for freight carriers, logistics companies and shippers in the retail and manufacturing sectors. The award ceremony was held at the 2017 American Trucking Associations Annual Management Conference & Exhibition in Orlando, Florida. The Award honors the top 1 to 2 percent of SmartWay partners that reduce their operational costs through gains in freight efficiency, mitigating their transportation environmental footprints by using less energy and cleaner technologies to move goods across America.
- **Green Power Leaders:** EPA presented the 2017 Green Power Leadership Awards in conjunction with the Center for Resource Solutions (CRS) on Monday, October 23 during the Renewable Energy Markets Conference, (October 22-24, 2017 in New York City). The awards serve to recognize the leading actions of organizations, programs, and individuals that significantly advance the development of green power sources. An EPA evaluation panel reviews and evaluates all applications submitted by the deadline. Applications must be accurate and complete. EPA reviews all applicants to ensure that they are in good standing with EPA.
- **Reminders**:
    - **Due October 27th:** Regional FY 17 ACS results due. (See my email from 10/12.)
    - **Due October 27th:** Confirm presenters and "desired understanding/outcomes" for the APM meeting. (See my email from 10/13.)
    - **Due October 30th:** Regional responses to the initial bids are due in ACS. (See my email from 10/3.)

- **Due November 3rd:** Presentations and read-ahead materials for the APM meeting. (See my email from 10/13.)

Upcoming Meetings & Events:

- **APM Meeting:** November 14th – 16th, Philadelphia, Pennsylvania. More information here.
- **SIP Training:** January 23rd – 25th, RTP, North Carolina.

Recent EPA News Releases for Air

- EPA Releases Guidance on Reporting Air Emissions of Hazardous Substances from Animal Waste at Farms; Release Date: 10/26/2017
- EPA Provides Support to New Jersey for Program to Cut Diesel Emissions; Release Date: 10/26/2017
- EPA Launches Air Quality Study in Kansas City, Kan., Neighborhoods; Release Date: 10/26/2017
- Top EPA Presidential Nominees Approved By Senate EPW Committee; Release Date: 10/25/2017
- EPA Releases Energy Independence Report; Release Date: 10/25/2017
- EPA Awards $25K Grant to Lewiston, Maine Non-profit for Indoor Air Quality Efforts; Release Date: 10/25/2017
- EPA awards Utah $2.3M to reduce diesel emissions along the Wasatch Front; Release Date: 10/24/2017
- EPA Honors 2017 Green Power Leaders; Release Date: 10/23/2017

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OAR Lead Region SharePoint Site

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U.S. Environmental Protection Agency

Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783

October 25, 2017

Environmental Protection Agency
Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783

Executive Summary

On March 28, 2017, President Trump signed Executive Order 13783, Promoting Energy Independence and Economic Growth. The Executive Order establishes a national policy to promote the clean and safe development of domestic energy resources while avoiding unnecessary regulatory burdens. It directs federal agencies to "review all existing regulations, orders, guidance documents, policies, and any other similar agency actions (collectively, "agency actions") that potentially burden the development or use of domestically produced energy resources[.]"[1] The Executive Order also orders the U.S. Environmental Protection Agency (EPA) to review specific rules. As part of E.O. 13783, agencies are to develop a report detailing this review that includes recommendations for reducing unnecessary regulatory burdens.

Through implementation of environmental statutes such as the Clean Air Act and Clean Water Act, EPA promulgates regulations that may affect domestic energy use and resources. Under Administrator E. Scott Pruitt's leadership, EPA is working to fulfill its critical mission while ensuring regulations are consistent with underlying laws and policies. Implementation of E.O. 13783 and other presidential directives related to regulatory reform plays an important role in this effort.

In order to identify priority areas and specific regulations for potential repeal, replacement, or modification pursuant to E.O. 13783, EPA has coordinated its review with other Administration initiatives, such as the Presidential Memorandum on Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing,[2] and E.O. 13777 on Enforcing the Regulatory Reform Agenda.[3] Notably, Administrator Pruitt established a Regulatory Reform Task Force (RRTF) pursuant to E.O. 13777, which has also served to lead implementation of the Section 2 review required under E.O. 13783.[4]

EPA issued a request for public comments to inform the RRTF on April 11, 2017.[5] As a result of this outreach, EPA received over 460,000 public comments, including a record-breaking number of 63,346 individual responses. Additionally, EPA program offices conducted nearly a dozen public

[1] 82 Fed. Reg. 16093 (Mar. 28, 2017).
[2] 82 Fed. Reg. 8667 (Jan. 30, 2017).
[3] 82 Fed. Reg. 12285 (Mar. 1, 2017).
[4] Memorandum from E. Scott Pruitt, Adm'r, U.S. Envtl Protection Agency, to Acting Deputy Adm'r, U.S. Envtl Protection Agency (Apr. 19, 2017) available at https://epa.gov/laws-regulations/epa-implementation-executive-order-13783-promoting-energy-independence-and-economic
[5] EPA-HQ-OA-2017-0190 available at https://www.regulations.gov/document?D=EPA-HQ-OA-2017-0190-0001.

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meetings in April and May to hear directly from stakeholders on EPA regulations and opportunities for reform.[6]

Many of the public comments centered on specific rulemakings and/or specific provisions of rulemakings that may unduly burden domestic energy production and use. Through this robust public feedback, the RRTF identified recurrent themes regarding EPA's energy-related regulations. These general themes included a need for streamlining complex permitting programs, restoring EPA's co-regulatory relationship with the states, increasing transparency pertaining to the economic impact of agency actions, and enhancing EPA's understanding of the entities it regulates.

In an effort to meet the requirements of E.O. 13783, EPA identified four key initiatives that it believes will further the goal of reducing unnecessary burdens on the development and use of domestic energy resources. These initiatives include: (1) comprehensive New Source Review reform, (2) National Ambient Air Quality Standards (NAAQS) reform, (3) robust evaluations of the employment effects of EPA regulations, and (4) a sector-based outreach program. Furthermore, the appendix of this report includes summaries of actions that EPA has already taken on rules identified for review, either specifically or generally, in E.O. 13783. Together, these efforts will help advance the Administrator's vision for EPA while fulfilling the President's goal of promoting domestic energy production and use.

I. New Source Review Reform

The Clean Air Act (CAA) establishes a number of permitting programs designed to reduce air pollution, primarily through the use of pollution control technology. New Source Review (NSR) is a preconstruction permitting program intended to ensure that new and modified stationary sources of air pollution do not significantly degrade air quality. NSR permits are legal documents that establish site-specific requirements that facility owners/operators must observe. The permit specifies what construction is allowed, what emission limits must be met, and often how the emissions source may be operated. There are three types of NSR permits: (1) Prevention of Significant Deterioration (PSD) permits (CAA Title I, Part C), which are required for new major sources or a major source making a major modification in an area that is in attainment with NAAQS air-quality standards; (2) Nonattainment NSR (NNSR) permits (CAA Title I, Part D), which are required for new major sources or major sources making a major modification in a nonattainment area; and (3) Minor source permits (CAA § 110(a)(2)(C)).

The potential costs, complexity, and delays that may arise from the NSR permitting process can slow the construction of domestic energy exploration, production, or transmission facilities that must undergo review. In some circumstances, the NSR process discourages the construction of new

[6] *See* https://www.epa.gov/laws-regulations/regulatory-reform#Public.

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facilities or modifications of existing ones that could result in greater environmental improvements. Such reactions to the NSR process slows the growth of domestic energy resources and raise energy costs, among other impacts.

Numerous public comments in response to the request for comments on E.O. 13777, and the Presidential Memorandum on Streamlining Permitting, raised concerns with the NSR program's impact on domestic energy resources. Commenters noted that the NSR permitting process is unduly lengthy and complex. Commenters further stated that the NSR application and construction costs are exceedingly high, to the point of discouraging industry from modernizing facilities for fear of triggering NSR obligations.

Several commenters suggested that EPA should defer to state decisions on the applicability of NSR requirements and other source-specific permitting decisions. Commenters also raised concerns about the availability and cost of emissions offsets in nonattainment areas, and about whether costs will increase as various NAAQS are revised.

Commenters recommended reforms to allow the purchase of offsets from outside a nonattainment area, and inter-pollutant trading. Commenters also urged EPA to better promote and facilitate use of Plant-wide Applicability Limitations, which generally can allow domestic energy production facilities to modify equipment and operations without concerns of triggering NSR requirements. Finally, recommendations included reviewing the debottlenecking rule and re-proposing it to address NSR requirements for modifying sources.

The above comments represent just some of the issues raised in public comments related to NSR. Accordingly, EPA believes opportunities exist to simplify the NSR application and permit process; to review ways to reduce the length of the permitting process; to review burdens created by the current emissions offsets structure; to improve relationships with the states; and to review the "once in, always in" policy to clarify the means by which a facility currently classified as a major source can become an area source.

To address these important areas and achieve meaningful NSR reform, Administrator Pruitt intends to convene an NSR Reform Task Force, details of which will be announced in a forthcoming agency memorandum.

II. National Ambient Air Quality Standards (NAAQS) Reform

Pursuant to the CAA, EPA sets NAAQS for six criteria pollutants: ozone, nitrogen dioxide (NO_2), sulfur dioxide (SO_2), particulate matter (PM_{10} and $PM_{2.5}$), carbon monoxide (CO), and lead. In setting the NAAQS, EPA establishes primary standards to protect public health and secondary

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standards to protect public welfare. EPA must review and, if appropriate, revise each NAAQS every five years.

After EPA sets a new NAAQS or revises an existing standard for each criteria air pollutant, the CAA requires EPA to determine if areas meet the new standard. Based on monitoring data or modeling, states and tribes submit recommendations to EPA on whether an area meets NAAQS for a criteria pollutant. After reviewing the recommendations and the available information, EPA "designates" an area as attainment or nonattainment (or unclassifiable) for the standard. States develop State Implementation Plans (SIPs) demonstrating that the state has the basic required elements of an air quality program (so-called "infrastructure SIPs" or "i-SIPs") and identifying emissions control requirements the state will rely upon to attain and/or maintain the primary and secondary NAAQS ("attainment" and "maintenance" SIPs).

NAAQS requirements, and revision of the NAAQS standards, have the potential to impact all facilities that emit a NAAQS pollutant or its precursor substances, including those facilities that generate energy from, oil, and natural gas. These facilities can be impacted whether they are in attainment areas or nonattainment areas. As a result, facilities face burdens including higher costs, greater uncertainties in making future plans, and a potential facility closure that not only impacts employment, but also affects communities that rely on the facility.

In response to EPA's request for comments on E.O. 13777, commenters raised concerns with the stringency of some NAAQS, as well as the short review time between revisions. Each new or revised NAAQS requires a host of rules, guidance, and technical support documents for use by state, local, and tribal regulators, as well as industry. The increased frequency of NAAQS revisions results in overlapping requirements that must be implemented in short time spans. Planned and permitted facilities are subject to significant uncertainty, making it difficult to anticipate future air quality improvement requirements and restricting economic growth. Frequent NAAQS revisions may further require that states modify their SIPs before previous standards can be fully implemented, and can also result in permitting delays for new facilities as new air quality assessments are conducted.

Other comments focused on NAAQS implementation issues. Commenters requested that EPA develop implementation guidance that corresponds with NAAQS rulemaking in a timely manner. They recommended that implementation guidance and the various other regulatory and analytic tools be available and final at the time the new or revised NAAQS are promulgated, and not years later, as has repeatedly occurred in recent years. Moreover, uncertainty and delays in guidance and implementation requirements may needlessly obstruct energy expansion and modernization of existing facilities.

Concerns were further expressed regarding the unnecessary burden arising from the development and revision of SIPs, and the chronic backlog of federal SIP approvals. At the end of fiscal year 2016,

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EPA had a backlog of 322 SIPs.[7] Commenters noted that many state SIP submittals remain without EPA action for years, and that the process for developing, submitting and approving SIPs is inefficient and outdated. Commenters also noted that EPA will second-guess state permitting decisions, affecting state control of the process and introducing delays and financial risks for companies seeking permits. Comments further recommended EPA defer to state authorities for source-specific decisions and, therefore, readjust its focus to overarching guidance and policy.

Commenters additionally questioned specific NAAQS – particularly the 2015 ozone standard – which approach background concentrations in some regions. Other commenters articulated concerns regarding monitoring and modeling issues, international and long-range ozone transport, stratospheric ozone intrusions, and exceptional events.

EPA received recommendations to revise the exceptional events rule and associated guidance to allow for greater state flexibility in flagging and excluding exceptional events in the data set used to determine compliance with NAAQS. Exceptional events are unusual or naturally occurring actions that can affect air quality, but are not reasonably controllable using techniques that may be implemented to attain and maintain NAAQS. Exceptional events include wildfires, stratospheric ozone intrusions, and volcanic and seismic activities.

To review the issues related to the ozone NAAQS, the Administrator formed the Ozone Cooperative Compliance Task Force. Among its priorities, the Task Force is reviewing administrative options to enable states to enter into cooperative agreements with EPA to provide regulatory relief and meaningfully improve ozone air quality. Moreover, EPA plans to work to streamline SIP approvals through a nationally consistent process that includes setting performance targets, and better monitoring progress on SIP reviews. EPA further plans to work to eliminate the SIP backlog.

III. Employment Evaluations

Regulatory costs impose tremendous burdens on American businesses, employees, and consumers – particularly within the energy sector. In its *2015 Report to Congress on the Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act*, the Office of Management and Budget estimated that the total annual cost of EPA regulations from October 1, 2004 through September 30, 2014 stood between $37.6 and $45.4 billion (2010$).[8] These costs may impact business development and expansion, as well as capital investment and employment patterns.

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[7] *Fiscal Year 2018 Justification of Appropriation Estimates for the Committee on Appropriations*, U.S. ENVTL PROTECTION AGENCY, EPA-190-K-17-002 (May 2017) available at https://www.epa.gov/sites/production/files/2017-06/documents/fy18-cj-14-program-performance.pdf

[8] OFFICE OF MGMT. & BUDGET, EXEC. OFFICE OF THE PRESIDENT, *2015 Report to Congress on the Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act* (2015), available at https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/2015_cb/2015-cost-benefit-report.pdf.

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In the CAA,[9] the Clean Water Act,[10] the Toxic Substance and Control Act,[11] Solid Waste Disposal Act,[12] and the Comprehensive Environmental Response, Compensation, and Liability Act,[13] Congress expressed its intent that EPA conduct continuing evaluations of potential losses or shifts of employment that may result from implementation of these statutes.[14] However, the Agency historically has not conducted these assessments. EPA acknowledges the importance of considering the cumulative effects of its regulations on the American public. Accordingly, EPA intends to conduct these evaluations consistent with the statutes.

IV. Smart Sectors

To accomplish the goals of E.O. 13783, EPA acknowledges that it must work to develop better relationships with the regulated community to close information gaps through informal means. Engaging these stakeholders in a collaborative manner to understand technological advancements or to coordinate on regulatory developments could reduce conflicts that complicate the rulemaking process.

Accordingly, EPA recently announced its *Smart Sectors* program to re-examine how it engages with industry to reduce unnecessary regulatory burdens, improve regulatory forecasting and predictability, and improve the ability of both EPA and industry to conduct long-term regulatory planning while also improving the environment and public health.[15] EPA initially identified thirteen sectors to work with, including ones directly related to oil and gas, utilities, mining, power generation, and the automotive industry.

The *Smart Sectors* program designates staff-level points of contact who are highly knowledgeable about specific industries. These individuals will act as liaisons among industry trade associations and companies, EPA program and regional offices, state and local governments, and other stakeholder groups. The sector liaisons will focus their attention on three main areas: building relationships and improving customer service to sectors; developing additional expertise in each industry's operations and environmental performance; and informing the planning of future policy, regulations, and Agency processes.

EPA anticipates that participating industries will benefit from coordinated, cooperative, and constructive problem-solving with government. The Agency will invite participating industries to

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[9] 42 U.S.C.§7621.
[10] 33 U.S.C. §1367.
[11] 15 U.S.C. §2622.
[12] 42 U.S.C. §7001(e).
[13] 42 U.S.C. §9610.
[14] 42 U.S.C. §7621(a); 33 USC §1367(e); 42 U.S.C. §700142 U.S.C. §9610(e).
[15] *See* https://www.epa.gov/smartsectors.

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engage in active dialogue and offer their own innovative ideas to reduce environmental impacts. Beginning in January 2018, EPA plans to release monthly updates on its *Smart Sectors* website with data and other information.

Conclusion

Multiple ways exist for EPA to protect the environment and public health while supporting the President's policy to promote economic growth and energy independence. The four key initiatives identified herein will advance the goal of reducing unnecessary regulatory burdens on the development and use of domestic energy resources in accordance with E.O. 13783. These initiatives also illustrate meaningful progress towards fulfilling Administrator Pruitt's efforts to satisfy EPA's core mission through increased transparency, public participation, and cooperative federalism.

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APPENDIX

This appendix includes summaries of the actions that EPA has taken on (1) rules that were identified specifically for review in E.O. 13783; and (2) other energy-related rules identified for review by EPA pursuant to E.O. 13783.

I. Rules Identified Specifically in E.O. 13783

A. Clean Power Plan and Related Rules

E.O. 13783 Section 4 addresses the Clean Power Plan and related rules that affect the electric utility sector, particularly utilities' fossil fuel-fired power plants – i.e., primarily coal and natural gas. EPA initiated a review of the two identified final rules and withdrew a proposed rule.

1. Carbon Emission Guidelines for Existing Stationary Sources (Clean Power Plan)

On October 23, 2015, EPA issued a final rule, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Clean Power Plan or CPP).[16] This rule established the first-ever standards for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Affected domestic energy resources include oil, natural gas, and coal.

On February 9, 2016, the U.S. Supreme Court issued an unprecedented stay of the CPP implementation pending judicial review.[17] Following a full briefing on the merits, oral argument was held before the D.C. Circuit, sitting *en banc*, on September 27, 2016. The case is currently pending in the D.C. Circuit.

Pursuant to E.O. 13783, on March 28, 2017, Administrator Pruitt signed a notice to review this final rule.[18] On March 28, 2017, the Department of Justice requested that the D.C. Circuit hold in abeyance the litigation regarding the CPP. On April 28, 2017, the D.C. Circuit ordered the litigation regarding the CPP be held in abeyance for 60 days.[19] On May 15, 2017, the Department of Justice submitted a supplemental brief to the Court urging the Court to continue to hold the cases in abeyance while EPA conducts its review of the CPP.[20] On June 6, 2017, EPA submitted a CPP proposal to OMB.[21] On August 8, 2017, the D.C. Circuit ordered litigation be held in abeyance for an additional

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[16] 80 Fed. Reg. 64661 (Oct. 23, 2015).
[17] *West Virginia v. EPA*, U.S., No. 15A773 (Feb. 9, 2016).
[18] 82 Fed. Reg. 16329 (Apr. 4, 2017).
[19] *West Virginia v. EPA*, D.C. Cir. *en banc*, No. 1673071 (Apr. 28, 2017).
[20] *West Virginia v. EPA*, D.C. Cir. *en banc*, No, 1675243 (May 15, 2017).
[21] https://www.reginfo.gov/

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60 days.[22] On October 10, 2017, Administrator Pruitt signed a Notice of Proposed Rulemaking proposing to repeal the CPP.[23] The public comment period closes on December 15, 2017. On October 10, 2017, EPA also submitted an advanced notice of proposed rulemaking, State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, to OMB.[24]

2. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources

On October 23, 2015, EPA issued a final rule, "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units."[25] This rule established standards for emissions of carbon dioxide (CO_2) for newly constructed, modified, and reconstructed affected fossil fuel-fired EGUs. Affected domestic energy resources include oil, natural gas, and coal.

Pursuant to E.O. 13783, on March 28, 2017, Administrator Pruitt signed a notice to review the final rule.[26] On March 28, 2017, the Department of Justice requested that the D.C. Circuit hold in abeyance the litigation regarding the rule, including the scheduled April 17, 2017, oral arguments.[27] On March 30, 2017, the D.C. Circuit granted the request to hold the litigation in abeyance.[28]

3. Federal Plan/Model Trading/Framework Rule

On October 23, 2015, in connection with the CPP, EPA published a proposed rule, "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule."[29] This rule proposed (1) a Federal plan to implement the CPP emission guidelines, (2) model trading rules to aid implementation of the guidelines, and (3) amendments to the existing framework regulations implementing CAA §111(d). Affected domestic energy resources include oil, natural gas, and coal.

Pursuant to E.O. 13783, on March 28, 2017, Administrator Pruitt signed a notice withdrawing these proposed rules.[30] The notice also included the withdrawal of the proposed design details of the Clean Energy Incentive Program (CEIP) under the CPP.[31]

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[22] *West Virginia v. EPA*, D.C. Cir. *en banc*, No. 1687838 (Aug. 8, 2017).
[23] 80 Fed. Reg. 48035 (Oct. 16, 2017).
[24] https://www.reginfo.gov/
[25] 80 Fed. Reg. 64509 (Oct. 23, 2015).
[26] 82 Fed. Reg. 16330 (Apr. 4, 2017).
[27] *North Dakota v. EPA*, D.C. Cir., No. 1668276 (Mar. 28, 2017).
[28] *North Dakota v. EPA*, D.C. Cir., No. 1668612 (Mar. 30, 2017).
[29] 80 Fed. Reg. 64966 (Oct. 23, 2015).
[30] 82 Fed. Reg. 16141 (April 3, 2017).
[31] 81 Fed. Reg. 42940 (June 30, 2016).

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B. Methane Emissions Standards for Oil and Natural Gas Sector

On June 3, 2016, EPA issued a final rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources."[32] This rule included amendments to the existing standards for the oil and natural gas source category (subpart OOOO) and set first-time standards for both GHGs (specifically methane) and volatile organic compounds (VOC) (subpart OOOOa).

Pursuant to E.O. 13783, on March 28, 2017, Administrator Pruitt signed a notice to review the final rule.[33] On April 7, 2017, the Department of Justice requested that the D.C. Circuit hold in abeyance the litigation regarding the oil and gas methane rule, including the scheduled oral arguments.[34] On May 18, 2017, the D.C. Circuit granted the request to hold the litigation in abeyance until EPA has completed its review and reconsideration of the 2016 rule.[35]

On April 18, 2017, Administrator Pruitt signed a letter that announced EPA's intent to convene a proceeding for reconsideration of the following objections relative to the fugitive emissions requirements: (1) the applicability of the fugitive emissions requirements to low production well sites, and (2) the process and criteria for requesting and receiving approval for the use of an alternative means of emission limitations (AMEL) for purposes of compliance with the fugitive emissions requirements in the 2016 rule.[36] On May 26, 2017, Administrator Pruitt signed a notice of reconsideration related to (1) the requirements for certification of closed vent system by a professional engineer, and (2) the well site pneumatic pump standards, and a partial stay of the rule requirements pending reconsideration.[37]

On June 12, 2017, Administrator Pruitt signed a proposed rulemaking for a three-month stay[38] and a separate notice proposing a two-year stay.[39] EPA currently has supplemental notices to these proposals under OMB interagency review.[40, 41]

II. Other Energy-Related Rules Identified by EPA

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[32] 81 Fed. Reg. 35824 (June 3, 2016).
[33] 82 Fed. Reg. 16331 (Apr. 4, 2017).
[34] *API v. EPA*, No. 13-1108 (and consolidated cases), D.C. Cir., No. 1670157 (Apr. 7, 2017).
[35] *API v. EPA*, No. 13-1108 (and consolidated cases), D.C. Cir., No. 1675813 (May 18, 2017).
[36] EPA Administrator E. Scott Pruitt, letter to API et al. (Apr. 18, 2017).
[37] 82 Fed. Reg. 25734 (June 5, 2017). Note that the D.C. Circuit vacated the 90 day stay on July 3, 2017. The court also emphasized that nothing in its opinion limits EPA's authority to reconsider the oil and gas standards and to proceed with its June 16, 2017 proposed two-year stays of certain requirements in the rule.
[38] 82 Fed. Reg. 27641 (June 16, 2017).
[39] 82 Fed. Reg. 27645 (June 16, 2017).
[40] https://www.reginfo.gov/
[41] https://www.reginfo.gov/

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As noted previously, the Administration has initiated several regulatory reform efforts, allowing EPA to leverage the ideas and information collected from those efforts to support and focus its activities to alleviate unnecessary burdens on the domestic energy sector. Public input has been received in response to both the Department of Commerce's request for information (RFI) regarding the Presidential Memorandum Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing,[42] and EPA's request for comment pursuant to E.O. 13777 in order to identify regulations that may be appropriate for repeal, replacement, or modification. EPA has screened each docket for comments with substantive, specific suggestions to remove regulatory burdens on the development or use of domestic energy resources. As part of this effort, the RRTF has identified the following additional energy-related actions EPA has taken:

A. Oil and Gas Information Collection Request

On November 10, 2016, EPA sent an information collection request (ICR) to more than 15,000 owners and operators in the oil and gas industry, requiring them to provide information on equipment inventories and methane emissions. This ICR conducted pursuant to CAA §114 was to assist the Agency in developing emissions standards for existing oil and gas facilities pursuant to CAA §111(d).[43]

On March 2, 2017, Administrator Pruitt withdrew the ICR.[44] The withdrawal will allow EPA to assess the need for the information that the Agency was collecting through these requests, and reduce burdens on businesses while the Agency assesses such need. EPA estimated the burden of the information collection to be 284,751 hours, costing $42,453,050. Due to some facilities submitting responses to the ICR prior to the withdrawal, EPA estimated that the withdrawal saved approximately $37 million in reporting burden. Affected domestic energy resources include oil and natural gas.

B. Mid-Term Evaluation for Light-Duty Vehicle Greenhouse Gas Emissions Standards

In 2012, EPA and the Department of Transportation's National Highway Traffic Safety Administration (NHTSA) set GHG emissions and Corporate Average Fuel Economy (CAFE) standards for model year (MY) 2017 and beyond for light-duty vehicles.[45] The 2012 joint rulemaking included a regulatory requirement for EPA to conduct a Mid-Term Evaluation (MTE) of the GHG standards established for MY 2022-2025 to assess whether the standards were appropriate no later

[42] The RFI resulted in 170 comments. Most EPA-relevant comments focused on air permitting programs (e.g. NSR, Title V, SSM, etc.).
[43] EPA ICR No. 2548.01.
[44] 82 Fed. Reg. 12817 (Mar. 7, 2017).
[45] 77 Fed. Reg. 62624 (Oct. 15, 2012).

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than April 1, 2018. On January 12, 2017, EPA issued, "Final Determination on the Appropriateness of the Model Year 2022-2025 Light-duty Vehicle Greenhouse Gas Emissions Standards under the Midterm Evaluation."[46] This action determined that the GHG emission standards for MY 2022-2025 light-duty vehicles were appropriate.

On March 15, 2017, Administrator Pruitt and Department of Transportation Secretary Elaine Chao announced that they intended to reconsider the final determination in order to allow for additional consultation and coordination, to ensure that the record is based on the best available data, and consistent with the schedule prescribed by the 2012 regulation. A formal notice of reconsideration was published in the Federal Register on March 22, 2017.[47] On August 21, 2017, EPA and DOT issued a request for public comment on its reconsideration of the Final Determination and invited stakeholders to provide any relevant comments, data, and information to inform the reconsideration.[48]

In accordance with the schedule set forth in EPA's regulations, the Agency intends to make a new Final Determination regarding the appropriateness of the MY 2022-2025 Light-duty Vehicle GHG Emissions Standards no later than April 1, 2018.

C. Steam Electric Effluent Limitations Guidelines

On November 3, 2015, EPA issued a final rule "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category."[49] This rule contained limitations and standards on various wastestreams at steam electric power plants: fly ash transport water, bottom ash transport water, flue gas mercury control wastewater, flue gas desulfurization (FGD) wastewater, gasification wastewater, and combustion residual leachate. This action affects domestic coal resources.

EPA received seven petitions for review of the 2015 Steam Electric ELG rule. On December 8, 2015, the United States Judicial Panel on Multi-District Litigation issued an order consolidating all of the petitions in the U.S. Court of Appeals for the Fifth Circuit.[50]

On April 11, 2017, the Administrator sent a letter to each state governor notifying them of the Agency's intent to consider postponing compliance dates as well as petitions for reconsideration of the final rule.[51] On April 12, 2017, the Administrator announced EPA's decision to reconsider the

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[46] 81 Fed. Reg. 87927 (Jan. 12, 2017).
[47] 82 Fed. Reg. 14671 (Mar. 22, 2017).
[48] 82 Fed. Reg. 39551 (Aug. 21, 2017).
[49] 80 Fed. Reg. 67838 (Nov. 3, 2015).
[50] *Southwestern Electric Power Co., et al. v. EPA*, 5th Citr. (Dec. 8, 2015).
[51] EPA Administrator E. Scott Pruitt, letter to Virginia Governor Terry McAuliffe (Apr. 11, 2017).

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final rule and, using authority under the Administrative Procedure Act §705, to postpone compliance dates that have not yet passed pending judicial review.[52] On September 18, 2017, EPA issued a final rule postponing compliance deadlines relating to FGD wastewater and bottom ash transport water from November 1, 2018, to November 1, 2020, while the Agency reconsiders those wastestreams in the 2015 rule.[53]

D. Coal Combustion Residuals

On April 17, 2015, EPA issued a final rule, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule."[54] This rule establishes minimum national criteria under subtitle D of the Resource Conservation and Recovery Act (RCRA) for Coal Combustion Residuals (CCR) landfills and surface impoundments at active coal-fired power plants. This action affects domestic coal resources.

Subsequent to the promulgation of the 2015 CCR rule, various environmental and industry groups submitted to the D.C. Circuit seven separate petitions for review, which have been consolidated into a single action. On June 14, 2016, the D.C. Circuit remanded with vacatur to EPA specific provisions of the rule for further consideration.[55] EPA is planning to issue a proposal to address those rule provisions by the end of 2017.[56]

On December 16, 2016, the President signed the Water Infrastructure Improvements for the Nation (WIIN) Act,[57] which included language giving state agencies the authority to implement and enforce coal ash regulations under the 2015 CCR Final rule through EPA-approved state permit programs. The WIIN Act also gives EPA the authority to regulate coal ash in states that choose not to implement state permitting programs and in states whose permitting programs are determined to be inadequate by EPA. EPA has direct implementing authority in Indian country.

On April 28, 2017, Administrator E. Scott Pruitt sent letters informing states that EPA was working on guidance for implementing state permitting programs under WIIN that allow flexibility in individual permits to manage the safe disposal of CCR. On August 15, 2017, EPA issued Interim Final Guidance for State CCR Permit Programs.[58] On September 14, 2017, EPA announced its intent

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[52] 82 Fed. Reg. 19005 (Apr. 25, 2017).
[53] 82 Fed. Reg. 43494 (Sept. 18, 2017).
[54] 80 Fed. Reg. 21302 (Apr. 17, 2015).
[55] *Utility Solid Waste Activities Group v. EPA*, D.C. Cir. (June 14, 2016).
[56] https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201704&RIN=2050-AG88.
[57] P.L. 114-322.
[58] 82 Fed. Reg. 38685 (Aug. 15, 2017).

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to reconsider several substantive provisions of the rule, as part of its rulemaking pursuant to the D.C. Circuit remand.[59]

E. Waters of the United States

On June 29, 2015, EPA issued a final rule, "Clean Water Rule: Definition of 'Waters of the United States'" (WOTUS).[60] The WOTUS rule is a definitional rule that affects the scope of the "waters of the United States;" it does not establish any regulatory requirements or directly mandate actions on its own. However, by changing the definition of the "waters of the United States," the rule changes the waters where other regulatory requirements that affect regulated entities come into play (i.e., the locations where regulated entities would be required to obtain certain types of permits). As a result, this action would have had wide-ranging effects on domestic energy production and use, including the permitting of oil, gas, coal, and renewable development sites, and the transmission and distribution of electricity.

Due to concerns about the potential for regulatory uncertainty, as well as the scope and legal authority of the 2015 WOTUS rule, 31 states and a number of other parties sought judicial review in multiple actions. On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the 2015 WOTUS rule nationwide pending further action of the court.[61]

On February 28, 2017, President Trump signed E.O. 13778 – Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the "Waters of the United States" Rule, which directed EPA and the U.S. Army Corp of Engineers to review the 2015 WOTUS rule.[62]

On June 27, 2017, EPA and the Army Corps signed a proposed rulemaking to repeal the 2015 WOTUS rule.[63] As indicated in the proposed withdrawal, the agencies are implementing E.O. 13778 in two steps to provide as much certainty as possible as quickly as possible to the regulated community and the public during the development of the ultimate replacement rule. In Step 1, the agencies are taking action to establish the legal status quo in the Code of Federal Regulations, by re-codifying the regulation that was in place prior to issuance of the 2015 rule. In Step 2, the agencies plan to propose a new definition that would replace the approach in the 2015 rule.

EPA has initiated programmatic staff workgroups to recodify the regulation that was in place prior to the 2015 WOTUS rule and consider a new definition that would replace the approach in the

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[59] EPA Press Release, "EPA to Reconsider Certain Coal Ash Rule Provisions" (Sept. 14, 2017).
[60] 80 Fed. Reg. 37054 (June 29, 2015).
[61] *Ohio v. U.S. Army Corps of Eng'rs.*, 6th Cir. (Oct. 9, 2015).
[62] 82 Fed. Reg. 12497 (Mar. 3, 2017).
[63] 82 Fed. Reg. 34899 (July 27, 2017) (NPRM).

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WOTUS rule with one that reflects the principles that Justice Scalia outlines in the *Rapanos* plurality opinion.

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Message

From: Pye Russell [prussell@mjbradley.com]
Sent: 5/24/2017 6:45:18 PM
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Attached please find MJB&A's Spring 2017 Issue Briefs. Topics covered by these briefs include proposed GHG and clean energy regulations in Massachusetts, the Energy Independence Executive Order, the California vehicle emissions standard waiver, and a review of the electric power industry in 2016.

MJB&A Issue Briefs
Spring 2017

Massachusetts Proposed Regulations under the Global Warming Solutions Act
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California's Light-Duty Vehicle Emissions Standards: The Clean Air Act Waiver, Standards History, and Current Status
Under the Clean Air Act, California is permitted to set its own vehicle emissions standards so long as it receives a waiver from the Environmental Protection Agency. California has done so regularly since the 1960s. However, it is unclear if the Trump Administration will continue to grant future waivers or review prior ones. This issue brief provides background on the Clean Air Act vehicle emissions waiver and the recent California standards to which it has applied, including a waiver application denied under President Bush when California first attempted to establish vehicle emissions standards for greenhouse gases. It then describes recent developments in federal vehicle emissions standards and explores possible implications for California's program.

Electric Industry: 2016 Year in Review
In many respects, 2016 could simply be characterized as a year of continuing market trends; on-going changes that have been reshaping the electric power sector in the United States for a decade or more. This would include: (1) a continuing decline in coal-fired power generation; (2) steady growth in natural gas-fired generation; (3) more renewables added to the system, including distributed resources; and (4) limited growth in electricity demand across much of the country (with some notable exceptions). But more than that, 2016 was also a year of major milestones, broken records, and a deepening sense that the industry continues to undergo fundamental change. This article provides an overview of the past year in the electric industry.

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Key Takeaways

- In response to the *Kain v. DEP* decision and Governor Baker's September 2016 Executive Order, MassDEP proposed regulations to ensure the state meets the GWSA's goals of reducing GHG emissions 25 percent below 1990 levels by 2020 and 80 percent below 1990 levels by 2050.
- The proposed regulations aim to achieve a 7.2 percent reduction in GHG emissions.[1] The electric generator emissions caps and CES are expected to achieve a 4 percent reduction.
- In response to the draft proposal, some stakeholders voiced concerns regarding the impacts of facility specific emissions caps and maintaining reliable and affordable energy for Massachusetts residents. For example, there is some concern that the regulations, as proposed, could result in emissions leakage forcing higher emitting out-of-state generators to run in order to compensate for changes in Massachusetts' power supply. MassDEP made some small changes to the regulations between the draft and proposal, but we expect similar comments to be offered on the proposal.
- The proposed CES will expand on the renewable energy supply required beyond the state renewable portfolio standard (RPS). While the regulation would result in a small amount of incremental growth in "clean energy" supplied to Massachusetts energy consumers in the early years, it would nearly double the amount of clean energy by 2050.
- As proposed, the CES provides incentive for new clean energy generators that commenced operation after 2010, but does not provide incentive for existing nuclear generation or renewable resources that commenced operation prior to 2010. MassDEP has proposed to include a requirement for MassDEP to complete an analysis and evaluate options to include existing low and zero-emitting resources in 2017 in the CES in the final rule.

[1] According to MassDEP, this is greater than the 5.3 percent reduction needed to meet the 2020 GHG reduction goal, providing headroom if one or more policies do not deliver the projected GHG emissions reduction benefits.

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Background

On May 17, 2016, the Supreme Judicial Court of Massachusetts held in *Kain v. DEP* that Section 3(d) of the GWSA requires MassDEP to "promulgate regulations that address multiple sources or categories of sources of greenhouse gas emissions, impose a limit on such emissions that may be released, limit the aggregate greenhouse gas emissions that are released from each group of regulated sources or categories of sources, set greenhouse gas emissions limits for each year, and set limits that decline on an annual basis." MassDEP also notes, however, that "the Court made clear that Section 3(d) regulations could be combined with other types of measures to achieve the 2020 limit."[2]

Additionally, on September 16, 2016, Governor Baker issued Executive Order 569, directing MassDEP to meet requirements of GWSA Section 3(d) by establishing final regulations to meet the 2020 emission reduction goals by August 11, 2017.

To comply with the Governor's Order, MassDEP released a discussion draft of proposed regulations on November 7, 2016, and released a proposal on December 16, 2016, for which comments are due February 24, 2017.

MassDEP is proposing regulations designed to achieve an estimated 7.2 percent reduction in GHG emissions between 2013 and 2020 from a 1990 baseline, with reductions coming mainly from the electric and transportation sectors. Of the 7.2 percent emission reductions, one tenth of a percent of the total emission reductions are expected to come from reducing SF_6 emissions from gas-insulated switchgear. One half of a percent is proposed to come from reducing methane leaks from the natural gas distribution system in the state. Just over three percent of the estimated emission reductions by 2020 are proposed to come from the transportation sector.

The remaining reductions are proposed to come from the electric sector. MassDEP finds that between 2013 and 2020, the proposed regulations will result in a 4 percent emission reduction from a 1990 baseline from three separate measures. First, in the background materials released by MassDEP, the agency concludes that the retirement of three coal plants[3] as well as the Pilgrim Nuclear power plant will result in a 0.2 percent increase in GHG emissions due to replacement with natural gas generation. Second, MassDEP estimates that new renewable generation will lower emissions by 2 percent based on RPS compliance and excess renewable generation available in the region. And, third, MassDEP projects that deploying cost effective energy efficiency and appliance standards will achieve an additional 2.2 percent emission reduction.

Reducing Greenhouse Gas Emissions from Electricity Generating Facilities Program

The proposed regulations under 310 CMR 7.74 would establish individual and aggregate GHG emissions caps for both existing and new power plants beginning in 2018. In 2018, the GHG emissions limit would be just over nine million metric tons of carbon dioxide equivalent ($MMTCO_2e$), and this cap would decline by 2.5 percent each year to a limit just under two $MMTCO_2e$ in 2050, achieving an 80 percent reduction in GHG emissions between 2018 and 2050.

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[2] Mass DEP, *Background Document On Proposed New and Amended Regulations*, Dec. 16, 2016 at p6 fn 5 (citing *Kain*, "Thus, to reach the twenty-five per cent reduction level by 2020, the Commonwealth would have to implement additional measures to achieve approximately seven per cent in further emissions reductions. The parties agree that these reductions need not be attributable solely to regulations passed pursuant to § 3 (d), but rather recognize that a variety of policies and programs, including actions taken under other statutory programs, such as the Green Communities Act, G. L. c. 7, § 9A, may produce measurable reductions.")

[3] Coal plant retirements include Brayton Point, Salem Harbor, and Mt. Tom by 2020.

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To establish this 2018 aggregate limit, MassDEP used the state's 2013 electric sector GHG emissions reported to the Massachusetts GHG Inventory, 12.55 $MMTCO_2e$,[4] incorporated anticipated reductions from current RPS requirements and energy efficiency policies, and identified anticipated generation or load changes through 2020, including planned coal-fired facility retirements.

Existing and New Facility Emission Limits

The proposed regulations would divide the GHG caps among new and existing plants by allocating 1.5 $MMTCO_2e$ for new sources and the remaining for existing facilities through 2025. From 2026 through 2050, both the new and existing facility aggregate limits decline annually by 2.5 percent of their respective 2018 aggregate GHG limits.[5] Proposed annual aggregate emissions limits are detailed in Appendix A.

Existing Facilities

To set the individual facility emission limits, MassDEP proposes to determine the percentage of total existing facility emissions for a given facility based on a three-year historic generation average[6] and apply this percentage to the aggregate emissions limit for that year. MassDEP established individual facility emissions limits for 2018 to 2025 based on each facility's 2013 to 2015 average generation.[7] Beginning in 2021, and for each year thereafter, MassDEP proposes to determine emission limits for existing facilities five years in advance based on data for the most recent three-year period available. For example, MassDEP would set a facility's 2026 emissions limit in 2021 based on 2018 to 2020 generation data.

MassDEP requests comment on alternative options to facility emission limit setting, such as establishing 2026 to 2050 limits every five years for a five-year period instead of on an annual basis, establishing 2026 to 2050 limits three years in advance instead of five, and whether an allowance and auction system would be more effective than individual facility limits.

New Facilities

For new facilities,[8] MassDEP proposes an emissions cap of 1.5 $MMTCO_2e$ for 2018 to 2025, which would decline by 2.5 percent of the 2018 aggregate new facility limit annually from 2025 to 2050. In the discussion draft regulations released in November 2016, MassDEP originally proposed an aggregate limit of 1.0 $MMTCO_2e$ for new facilities. However, the December proposal increased the limit based on the anticipated emissions of potential new generating facilities in response to comments expressing concern that the 1.0 $MMTCO_2e$ limit would hinder the state's ability to develop cleaner generating resources that would allow for compliance with the proposed emissions limits.

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[4] Statewide Greenhouse Gas Emissions Baseline, Inventory & Projection, Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2013, available at http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/greenhouse-gas-ghg-emissions-in-massachusetts.html.

[5] Mass DEP, *Background Document On Proposed New and Amended Regulations*, Dec. 16, 2016, Table 3.

[6] Owners or operators of a facility that report net steam output in accordance with the state's CO_2 budget trading program have the option to petition MassDEP to convert and include net steam output as part of the facility's annual generation in determining the facility's GHG emissions limit.

[7] The Brayton Point, Salem Harbor, and Mount Tom power plants are assumed not to be in operation in 2018, and therefore, were not included in this calculation.

[8] For purposes of this regulation, new facilities are those that have been operating for less than ten years, including such units at existing facilities.

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Each year, MassDEP proposes to set the emissions limit of a new facility as the actual emissions of the previous year. For example, the 2025 emissions limit for a new facility would be set in 2026 as the facility's actual emissions in 2025. If total new facility emissions in a given year are less than or equal to the aggregate new facility limit for that year, MassDEP would set the emissions limit for new facilities as the actual emissions from that calendar year.

Massachusetts anticipates at least three new generation units: the Salem Harbor replacement project—Footprint Power station—is expected to be completed by mid-2017; the West Medway addition expected to come online in the second half of 2018; and the Canal 3 plant is projected to be online in 2018. In the Air Quality Plan Approval for the Footprint Power station, MassDEP assigns an annual emissions limit of 2,279,530 $MTCO_2e$.[9] MassDEP's Final Air Quality Plan Approval for the proposed construction of two new simple cycle combustion turbines at the existing West Medway Facility includes a 2018 emissions limit of 506,665 $MTCO_2e$.[10] The Air Quality Plan Approval for the Canal 3 facility includes an annual emission limit of 810,500 $MTCO_2e$ beginning in 2019.[11] Thus, the new units are likely to exceed the proposed new unit cap once all three units are operating.

Over Compliance Credits

MassDEP is proposing to create a system of transferable over compliance credits (OCCs) that affected facilities can bank, transfer, or use for compliance purposes. The number of OCCs created would be the difference between the emission limit for that facility and the facility's actual emissions for that year. In the case that a generator exceeds its individual limit in a given year, the owner or operator would be required to surrender OCCs to demonstrate compliance for that year.

OCCs would be created when:

- emissions from a new or existing facility are less than its individual facility limit for that year,
- a facility retires or is no longer subject to EPA's GHG Reporting Program, or
- total new facility emissions are less than the aggregate new facility limit.

If total new facility emissions are less than the aggregate new facility cap, any remaining emissions would be converted into OCCs and apportioned to existing facilities. However, if total new facility emissions in a given year are greater than the aggregate new facility limit, individual new facility emission limits would be proportionally adjusted downward. Facilities would be required to purchase OCCs in the amount exceeding the limit to demonstrate compliance.

Commenters have suggested that the state OCC market may be illiquid, as the tight caps may lead existing sources to bank OCCs rather than trade them in the market. Some environmental NGOs, however, suggested that banking should not be allowed, and OCCs would only have value for the year in which they are created.

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[9] Massachusetts Department of Environmental Protection, Footprint Power Salem Harbor Development LP Plan Approval (January 30, 2014) available at http://www.mass.gov/eea/docs/dep/air/approvals/final2014/cpa-footprint14.pdf.

[10] Massachusetts Department of Environmental Protection, Exelon West Medway, LLC and Exelon West Medway II, LLC Final Air Quality Plan Approval (December 19, 2016) available at http://www.mass.gov/eea/docs/dep/air/approvals/final2016/exelonwm-faqpa.pdf.

[11] Massachusetts Department of Environmental Protection, NRG Canal 3 Development LLC Proposed Air Quality Plan Approval (January 5, 2017) available at http://www.mass.gov/eea/docs/dep/air/approvals/final2016/nrgcanal-paqpa.pdf.

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Clean Energy Standard

MassDEP is proposing to implement a CES under 310 CMR 7.75 to increase the amount of clean energy sold to electricity consumers in Massachusetts. Under the CES, a "clean energy" resource is defined as a resource that has commenced operation after 2010, and is either a RPS Class I renewable generation unit under Massachusetts's Renewable Energy Portfolio Standard, or a resource that demonstrates at least a 50 percent reduction in GHG emissions over a 20-year lifetime as compared to a new combined cycle natural gas electric generating facility. Thus, these resources can include new nuclear unit as well as new large-scale hydro-power.

In the documents released with the proposed rules, MassDEP notes that it worked with the Department of Energy Resources (DOER) to design the CES in a way that will support the RGGI and RPS programs, aligning much of the CES regulation with the state RPS requirements while also including out-of-state clean generation. With the proposed requirement, MassDEP projects that total state electricity sales procured from clean energy resources will reach 38 percent by 2030 and 80 percent by 2050.

Clean Energy Sales Requirements

The CES would establish a sales portfolio standard requiring retail electricity sellers and Municipal Light Plants (MLPs) to demonstrate they are using a specified percentage of clean energy each year beginning in 2018.

To establish the CES for retail electricity sellers, MassDEP took into consideration the existing Class I RPS, the estimated availability of "surplus" RPS-eligible energy in the region, and other clean energy that would not be renewable under the RPS, but that the state wanted to encourage to complement the recent energy bill, "An Act Relative to Energy Diversity"[12] (Energy Bill). For the years 2018 to 2020, DOER estimated a surplus of Class I RPS-eligible electricity between three and five percent of sales. Beginning in 2020, DOER estimated additional "clean energy" increasing by two percent annually through year 2050.

MassDEP is proposing to include a CES requirement on MLPs, which do not participate in the RPS program. MassDEP is proposing a phase-in plan for setting MLP clean energy standards, remaining at zero from 2018-2020, allowing MLPs to create and bank clean energy credits (CECs). From 2021 to 2049, the MLP standard will begin at 6 percent plus 1/30 of the retail seller standards, increasing by 1/30 of the retail seller standard each year until reaching 80 percent in 2050.

The incremental new clean energy as a result of the CES is equal to the CES minus the Class I RPS for each year, plus the CES for Municipal Light Boards (MLPs). For example, in 2030, the Class I RPS is 25 percent, the CES is 40 percent, therefore, the additional clean energy generation resulting from the CES is 15 percent for retail sellers, and 23 percent for MLPs. Appendix B includes the total percentage of sales covered by clean energy through year 2050.

Some stakeholders have commented that the proposed regulation is not designed in a way that would result in significantly greater renewable energy production, and that with expected growth in renewable generation, there will be insufficient demand for the additional power.

Compliance

MassDEP is proposing that retail electricity sellers use CECs generated in or outside of Massachusetts to comply with the CES.[13] A retail electricity seller will be required to obtain an amount of CECs equal to annual electricity

[12] H. 4568, "An Act Relative to Energy Diversity" was signed by Governor Baker on August 8, 2016.

[13] Consistent with RPS geographic eligibility, MassDEP is proposing that all CES clean generation units be located in the ISO-NE region with special provisions for qualifying resources located outside the ISO-NE area. Clean generation units located outside of the

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sales multiplied by the standard for that year. Further aligning RPS and CES compliance, MassDEP proposes that RPS Class I RECs be eligible to create CECs and all tracking of CECs will take place in the same NEPOOL-GIS tracking system as used for RPS compliance. CECs can be banked and used toward compliance in future years.

MassDEP is also proposing a CES Alternative Compliance Payment (ACP) that will generate CES alternative compliance credits equal to 50 percent of the RPS ACP rate for a given year.[14] DOER proposes to use the ACP payments to advance clean energy programs in the state to help meet climate goals. MassDEP requests feedback on the necessity for this mechanism, whether the proposed CES provides enough flexibility, and whether a multi-year compliance strategy may be more effective.

Conclusion

MassDEP will review comments on the proposed regulations and issue final regulations by August 11, 2017, as required by Executive Order 569. In issuing final emissions caps for electric generators, MassDEP will need to consider the regional impacts of limiting Massachusetts electric generator emissions so that compliance does not increase GHG emissions in neighboring states. Consideration of new facility treatment will play into how overall electric sector emissions are achieved in the state, and MassDEP will need to determine how emissions limits will achieve 2020 and 2050 climate goals while still encouraging the development of more efficient generating units. With respect to the CES, MassDEP will continue to consider stakeholder feedback on whether the regulation should be distinct and in addition to the existing RPS with the regulatory goal of increasing clean energy resources delivering electricity to the Commonwealth.

ISO-NE region, will be considered an eligible resource under the CES if the energy supplied from the site to Massachusetts is delivered through a dedicated transmission line.

[14] The 2015 ACP rate for Class I resources was $67.07/MWh

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Appendix A.

Total Aggregate, Existing Facility Aggregate, and New Facility Aggregate GHG Emissions Limits (Metric Tons CO_2e)

Year	Total Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2018	9,119,126	7,619,126	1,500,000
2019	8,891,148	7,391,148	1,500,000
2020	8,663,170	7,163,170	1,500,000
2021	8,435,192	6,935,192	1,500,000
2022	8,207,213	6,707,213	1,500,000
2023	7,979,235	6,479,235	1,500,000
2024	7,751,257	6,251,257	1,500,000
2025	7,523,279	6,023,279	1,500,000
2026	7,295,301	6,095,301	1,200,000
2027	7,067,323	5,904,823	1,162,500
2028	6,839,345	5,714,345	1,125,000
2029	6,611,366	5,523,866	1,087,500
2030	6,383,388	5,333,388	1,050,000
2031	6,155,410	5,142,910	1,012,500
2032	5,927,432	4,952,432	975,000
2033	5,699,454	4,761,954	937,500
2034	5,471,476	4,571,476	900,000
2035	5,243,497	4,380,997	862,500
2036	5,015,519	4,190,519	825,000
2037	4,787,541	4,000,041	787,500
2038	4,559,563	3,809,563	750,000
2039	4,331,585	3,619,085	712,500
2040	4,103,607	3,428,607	675,000

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Year	Total Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2041	3,875,629	3,238,129	637,500
2042	3,647,650	3,047,650	600,000
2043	3,419,672	2,857,172	562,500
2044	3,191,694	2,666,694	525,000
2045	2,963,716	2,476,216	487,500
2046	2,735,738	2,285,738	450,000
2047	2,507,760	2,095,260	412,500
2048	2,279,781	1,904,781	375,000
2049	2,051,803	1,714,303	337,500
2050	1,823,825	1,523,825	300,000

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Appendix B.

Comparison of Existing Class I RPS, the proposed CES, and estimated total percentage of state electricity sales covered by clean energy.

Year	Existing RPS	CES for Retail Sellers	CES for MLPs	Total % of State Sales Covered by Clean Energy
2018	13%	16%	0%	14%
2019	14%	18%	0%	15%
2020	15%	20%	0%	17%
2021	16%	22%	7%	20%
2022	17%	24%	8%	22%
2023	18%	26%	10%	24%
2024	19%	28%	12%	26%
2025	20%	30%	13%	28%
2026	21%	32%	15%	30%
2027	22%	34%	17%	32%
2028	23%	36%	19%	34%
2029	24%	38%	21%	36%
2030	25%	40%	23%	38%
2031	26%	42%	26%	40%
2032	27%	44%	28%	42%
2033	28%	46%	30%	44%
2034	29%	48%	33%	46%
2035	30%	50%	35%	48%
2036	31%	52%	38%	50%
2037	32%	54%	40%	52%
2038	33%	56%	43%	54%
2039	34%	58%	46%	56%
2040	35%	60%	48%	58%
2041	36%	62%	51%	60%
2042	37%	64%	54%	63%
2043	38%	66%	57%	65%
2044	39%	68%	60%	67%
2045	40%	70%	63%	69%
2046	41%	72%	67%	71%
2047	42%	74%	70%	73%
2048	43%	76%	73%	76%

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Year	Existing RPS	CES for Retail Sellers	CES for MLPs	Total % of State Sales Covered by Clean Energy
2049	44%	78%	77%	78%
2050, and each year thereafter	45%	80%	80%	80%

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Summary and Implications of Executive Order on Promoting Energy Independence and Economic Growth

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Clean Power Plan and New Source Rule

The Executive Order on Energy Independence directs EPA to "suspend, revise, or rescind" the Clean Power Plan[2] and the 111(b) rule.[3] The Executive Order also directs EPA to suspend, revise, or rescind the Clean Power Plan Model Trading Rule and Federal Plan[4] and the Legal Memo released with the final Clean Power Plan.[5] It does not indicate a specific timeframe for this review or direct a specific policy outcome, though it directs the agency review "as soon as practicable." The Executive Order notes that this may require EPA to publish for notice and comment rules to take these actions. The Executive Order also directs the Attorney General to provide notice to the D.C. Circuit, and request the court stay or otherwise delay the litigation or seek other appropriate relief.

Following the release of the Executive Order, the Department of Justice (DOJ) filed a motion requesting that the D.C. Circuit hold the Clean Power Plan and 111(b) litigation in abeyance, which would suspend the litigation, but

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1 *See* https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1

2 *See* 80 Fed. Reg. 64661 (October 23, 2015). Available at https://www.federalregister.gov/documents/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

3 *See* 80 Fed. Reg. 64509 (October 23, 2015). Available at https://www.federalregister.gov/documents/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary

4 *See* 80 Fed. Reg. 64966 (October 23, 2015). Available at https://www.federalregister.gov/documents/2015/10/23/2015-22848/federal-plan-requirements-for-greenhouse-gas-emissions-from-electric-utility-generating-units

5 *See* https://www.epa.gov/sites/production/files/2015-11/documents/cpp-legal-memo.pdf

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the court would retain jurisdiction. DOJ noted that the rules may be significantly modified or rescinded, and that EPA should be afforded the opportunity to fully review the rules. In light of this, DOJ argued, deferral of further judicial proceedings is warranted. EPA has also withdrawn the draft federal plan and model rule[6] and has provided notice of review of the Clean Power Plan and 111(b) rules.[7]

States and environmental NGOs that have intervened in the Clean Power Plan and 111(b) cases on behalf of EPA have stated their opposition to DOJ's request in both of these cases, and have committed to continuing to defend the rule and opposing the deferral of proceedings. In the Clean Power Plan case, given that the D.C. Circuit has already held oral argument before the *en banc* panel, it is unclear whether the court will continue to finalize and release its decision or grant DOJ's motion. Because the 111(b) litigation has not yet proceeded as far, with oral argument currently scheduled for April 17, 2017, the court may treat this case differently.

Regardless of the litigation, EPA is now expected to start a rulemaking process to at least repeal the Clean Power Plan and 111(b) regulations. EPA may also decide to replace the rule with a regulation under section 111 that only requires measures "inside-the-fenceline." Under administrative law, to repeal or replace the Clean Power Plan, EPA must initiate a rulemaking process to revise or rescind the regulation, including a notice and comment process. If EPA does establish an inside-the-fenceline program, a key question will be what flexibility, if any, is afforded to covered sources in meeting established GHG limits.

At this time, the Trump Administration has not made its intent clear on whether EPA will undertake a process to undo the endangerment finding that finds that GHGs threaten human health. If EPA chooses to only repeal and not replace the Clean Power Plan, certain states and NGOs will likely sue, arguing EPA is not fulfilling its legal obligations under the Clean Air Act. The Trump Administration may decide at a later point to roll back the endangerment finding to avoid this outcome. However, because the Supreme Court ruled in *Massachusetts v. EPA* that EPA had the authority to regulate GHGs, this process would likely be legally complicated.

Furthermore, if EPA decides to not undertake a regulatory process to control GHGs from the power sector under section 111, or fails to enforce established limits, NGOs may start to file common law nuisance claims against specific power plants. In *AEP v. Connecticut,* the Supreme Court noted that if EPA did not set emissions limits for pollution sources or pollutants, states and private parties could petition for a rulemaking in federal court, and left open the possibility of state common law nuisance cases against sources of GHGs.

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[6] *See* 82 Fed. Reg. 16144 (April 3, 2017). Available at https://www.gpo.gov/fdsys/pkg/FR-2017-04-03/pdf/2017-06518.pdf

[7] *See* 82 Fed. Reg. 16329-16331 (April 4, 2017). Available at https://www.gpo.gov/fdsys/pkg/FR-2017-04-04/pdf/2017-06522.pdf and https://www.gpo.gov/fdsys/pkg/FR-2017-04-04/pdf/2017-06519.pdf.

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Paris Climate Agreement

During the campaign, President Trump promised to withdraw the U.S. from the Paris Climate Agreement. This Executive Order on Energy Independence does not directly address the U.S. commitments under the Paris Climate Agreement, which called for a 26 percent reduction of GHG emissions below 2005 levels by 2025. However, even with the Clean Power Plan, Obama-era methane regulations, vehicle fuel efficiency and GHG standards, and other regulations and programs threatened or rolled back by the Trump administration, the U.S. was projected to fall short of its GHG emissions reductions targets under the Agreement. It does not seem likely that the Trump Administration will establish policies that will place the nation on track to meet these targets. However, the U.S. could remain a party to the agreement and elect to not meet its target reductions.

Addressing Burdens on Domestic Energy Resources

The Executive Order on Energy Independence directs agencies to immediately review all rules, guidance, or policies that potentially "burden" the development of domestic energy resources, where burden is defined as "unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery" of these resources. This review is ordered to particularly focus on "oil, natural gas, coal, and nuclear energy resources." However, Section 1 of the Executive Order, addressing general policy, states that it is "in the national interest to ensure that the Nation's electricity is affordable, reliable, safe, secure, and clean, and that it can be produced from coal, natural gas, nuclear material, flowing water, and other domestic sources, including renewable sources."

By May 12, 2017, the head of each agency is directed to submit a draft plan to the Office of Management and Budget (OMB) Director, the Vice President, the Assistant to the President for Economic Policy, the Assistant to the President for Domestic Policy, and the Chair of the Council on Environmental Quality. A final draft report including recommendations to alleviate "burdens" is due July 26, 2017. The final report from each agency is due September 28, 2017, unless the OMB director extends this deadline. The OMB Director and the Assistant to the President for Economic Policy are responsible for the coordination of the final plan(s).

The Executive Order provides a broad directive and leaves the scope of regulations to be addressed up to the relevant agency.

Oil, Gas, and Coal Extraction Regulations

The Executive Order on Energy Independence directs EPA to review the final regulations on methane emissions for new, reconstructed, and modified oil and gas sources issued June 3, 2016, and any rules and guidance issued along with them.[8] If appropriate, the Order directs EPA to suspend, revise, or rescind these regulations "as soon as practicable." In addition, the Secretary of the Interior is directed to suspend, revise, or rescind multiple rules relating to oil and gas extraction, including those governing hydraulic fracturing on federal and Indian lands,[9]

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[8] *See* https://www.federalregister.gov/documents/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources

[9] *See* 80 Fed. Reg. 16128 (March 26, 2015). Available at https://www.federalregister.gov/documents/2015/03/30/C1-2015-06658/oil-and-gas-hydraulic-fracturing-on-federal-and-indian-lands

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general provisions and non-federal oil and gas rights,[10] and management of non-federal oil and gas rights.[11] The Executive Order also calls for a lifting of the moratorium on coal mining leases on federal lands.[12]

As a result of the Executive Order, EPA announced on April 4, 2017 that it will now undertake rulemaking proceedings to repeal or revise oil, gas, and methane regulations.[13] Because EPA's GHG endangerment finding included methane, it is likely that EPA could face litigation if it fails to meet its obligations to regulate under the Clean Air Act. By the afternoon after the Executive Order was signed, Secretary of the Interior Zinke had revoked the Department of the Interior (DOI) policy that had required offsetting development impacts on natural resources and ordered a review of all DOI rules on climate change, mitigation and energy development. The Secretary also lifted the moratorium on federal lands coal leasing, though concurrently announced a review of royalty rates. A coalition of NGOs has announced a federal lawsuit challenging the lifting of this moratorium.

In the short- to medium-term, it is unclear what affect these directives, as well as those relating to the unburdening of domestic energy resources, will have on the coal, oil, and natural gas markets. The expansion of coal mining operations could result in increased supply, lower prices, and could increase exports. Corresponding movements in the natural gas markets should be expected. While the absence of the Clean Power Plan may result in fewer or delayed coal plant closures, coal company executives have broadly stated that they do not expect a significant resurgence in production or output due to continued pressure from low gas and renewable prices and other federal and state regulations.

In the long term, the Executive Order could possibly remove hurdles to increasing U.S. liquefied natural gas (LNG) exporting capabilities. Global trade in LNG increased in 2016 7.5 percent compared to 2015 after remaining nearly flat for the previous four years, and numerous projects are underway in the U.S. now to build export terminals. While increased LNG export capability facilitated by this Executive Order could raise domestic natural gas prices, the infrastructure lead time to achieve this increase means that price impacts remain many years down the road.

Social Cost of Carbon

The Executive Order on Energy Independence also notes that it is essential that the costs and benefits used in regulatory analyses be "based on the best available science and economics." To that end, it directs that the Interagency Working Group, which established the Social Cost of Carbon, be disbanded and that several working documents produced by this group no longer be used to set governmental policy. Among others, these include the August 2016 Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis[14] and the August

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[10] *See* 81 Fed. Reg. 77972 (November 4, 2016). Available at https://www.federalregister.gov/documents/2016/11/04/2016-26489/general-provisions-and-non-federal-oil-and-gas-rights

[11] *See* 81 Fed. Reg. 79948 (November 14, 2016). Available at https://www.federalregister.gov/documents/2016/11/14/2016-27218/management-of-non-federal-oil-and-gas-rights

[12] *See* https://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.4909.File.dat/FINAL%20SO%203338%20Coal.pdf

[13] *See* 82. Fed. Reg. 16331 (April 4, 2017). Available at https://www.gpo.gov/fdsys/pkg/FR-2017-04-04/pdf/2017-06658.pdf

[14] *See* https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

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2016 Addendum on the Application of the Methodology to Estimate the Social Cost of Methane and Social Cost of Nitrous Oxide.[15]

The Executive Order directs that any future need to "monetiz[e] the value of changes in greenhouse gas emissions resulting from regulation" should be based on OMB Circular A-4 from September 2003.[16] While this circular does not address the valuation of GHG emissions reductions specifically, it outlines a general framework for conducting a cost-benefit analysis and identifies factors an agency should consider. Many expect that its application will significantly reduce the amount of benefit ascribed to GHG emissions reductions in this administration's policymaking.

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[15] *See* https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf

[16] *See OMB Circular A-4, "Regulatory Analysis, September 17, 2003.* Available at https://www.nap.edu/read/11534/chapter/10#264.

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California's Light-Duty Vehicle Emissions Standards: The Clean Air Act Waiver, Standards History, and Current Status

Under the Clean Air Act, California is permitted to set its own vehicle emissions standards so long as it receives a waiver from the Environmental Protection Agency. California has done so regularly since the 1960s. However, it is unclear if the Trump Administration will continue to grant future waivers or review prior ones. This issue brief provides background on the Clean Air Act vehicle emissions waiver and the recent California standards to which it has applied, including a waiver application denied under President Bush when California first attempted to establish vehicle emissions standards for greenhouse gases. It then describes recent developments in federal vehicle emissions standards and explores possible implications for California's program.

Clean Air Act and the Vehicle Emissions Waiver

When Congress passed the 1963 Clean Air Act, it authorized the first federal pollution control. In 1970, Congress amended the Act to establish the first comprehensive emissions standards for new automobiles for pollutants that could adversely affect human health. At that time, only California had established comparable state-level vehicle emissions standards, passed in 1967 through the Mulford-Carrell Act. In the hearings on Clean Air Act development, Senators from states across the country lauded California's leadership in this field. Thus, though Section 209 of the Clean Air Act barred any "State or any political division thereof" from implementing emission standards for new vehicles, it also allowed "any state which has adopted standards…prior to March 30, 1966"—i.e., California—to submit an application for a waiver from this restriction.

Section 209(b) explains that this waiver will only be granted if the state standards are, in aggregate, at least as protective of public health and welfare as the federal standards. It also states that no waiver will be granted if the administrator of the Environmental Protection Agency (EPA) finds that any of following three conditions are met:

- The state was arbitrary and capricious in its finding that its standards are, in the aggregate, at least as protective of public health and welfare as applicable federal standards;
- The state does not need such standards to meet compelling and extraordinary conditions; or
- such standards and accompanying enforcement procedures are not consistent with Section 202(a) of the Clean Air Act, which lay out the EPA requirements for federal vehicle emissions

When California files an application for waiver, EPA publishes notice for public hearing and written comment in the Federal Register. Once the comment period expires, EPA reviews the comments and the Administrator determines whether the requirements for obtaining a waiver have been met.

While only California can apply for a waiver under Section 209, other states can choose to adopt an approved California standard under Clean Air Act Section 177. For a state to adopt and implement California standards in lieu of federal standards, it must establish identical standards to California's at least two years before they are set to come into effect. These states, often called "Section 177 States," are not required to seek EPA approval of this

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decision, though their decision to adopt California's standards is usually discussed and justified in State Implementation Plans that address a state's path to meeting air quality standards and that are submitted to EPA.

California first requested a waiver under the Clean Air Act to set emissions standards in December 1970. Since that date, it has submitted more than 100 applications to the EPA, either for waivers for new emission standards or for confirmation that regulatory changes fell under existing authorized waivers. The vehicle emissions standards covered under these waivers apply to a range of vehicle types, including light-, medium-, and heavy-duty vehicles, motorcycles, off road vehicles, commercial harbor craft, urban buses, mobile cargo handling equipment, and cargo ships at berth in California harbors. With very few exceptions, EPA has granted the requested waiver allowing California to set its own emission standards for these vehicles: only six times, five of which occurred before 1976, did EPA deny California's waiver application; the sixth we discuss in more detail below.

Policy Background: California's Low Emissions Vehicle Program and Federal Standards

The era of California's contemporary vehicle emissions reductions began in 1990, when the California Air Resources Board (ARB) adopted the Low Emissions Vehicle (LEV) program which, among other things, set criteria pollutant emissions standards for passenger vehicles in model years 1994 through 2003. To comply with these standards, each automaker was required to calculate a "fleet" average emissions rate—an average rate of all new vehicles sold by that automaker. The fleet average for each pollutant required each year under the LEV program was lower than what was required under EPA's new vehicle emission standards in effect for the same model years. EPA approved California's waiver application for this program in January of 1993.[1] The LEV II regulations, passed in 1998, expanded upon this program, setting tighter fleet average emission standards for model years 2004 through 2010. LEV II also added more information on the use Zero Emissions Vehicle (ZEV) credits, which could be used by automakers to help lower their fleet emissions average. EPA approved a waiver for these standards in April 2003.[2] By 2007, 15 states had adopted California's standards under Section 177 effective for vehicles sold starting in model years between 2008 through 2010.[3]

Federally, EPA has also established criteria pollutant emissions standards for light duty vehicles, which began with passage of the Clean Air Act in 1970. The foundation for contemporary standards were formed in 1990, when Congress amended the Clean Air Act to define federal emissions standards that took effect for model year 1996. Since that date, the standards have been updated as increasingly stringent "tiers," though federal standards lagged behind California standards. Congress also enacted Corporate Average Fuel Economy (CAFE) standards in 1975, which aimed to improve average fleet-wide fuel economy of light duty vehicles. These standards were established and are managed by the Department of Transportation's National Highway Traffic Safety Administration (NHTSA), though EPA manages the testing program used to determine annual compliance. Set at less than 20 miles per gallon at their inception, these standards rose to around 27 mpg in the 1970s and stayed at this approximate level until 2012.

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1 58 Fed. Reg. 4166. Available at http://loc.heinonline.org/loc/Page?handle=hein.fedreg/058008&id=1&collection=journals&index=fedreg/058#116

2 68 Fed. Reg. 19811. Available at https://www.gpo.gov/fdsys/pkg/FR-2003-04-22/pdf/03-9910.pdf.

3 These states were: Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Jersey, New York, North Carolina, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, Washington. *See* https://iaspub.epa.gov/otaqpub/display_file.jsp?docid=16888&flag=1

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Vehicle Greenhouse Gas Emissions Standards: Waiver Denial and Reversal

In 2002, the California Legislature passed Assembly Bill 1493, which for the first time directed ARB to establish GHG emissions standards for passenger vehicles. These standards, often called the Pavely Standards for the Assemblywoman who sponsored their creation, were implemented in ARB regulation in 2004 as part of the revised LEV II, and were to apply to passenger vehicles and light trucks beginning with the 2009 model year. The ARB requested a waiver under Section 202 of the Clean Air Act in December 2005.[4]

Note that while the Pavely standards were the first direct vehicle GHG limits ever proposed in the U.S., the federal CAFE fuel economy standards in effect since the late 1970s were effectively defacto GHG standards applicable to all light duty vehicles sold in the U.S. (including California and other Section 177 states).

The Bush Administration EPA did not begin considering ARB's request until 2007. In spring of that year, the Supreme Court ruled in *Massachusetts v. EPA* that GHGs are air pollutants under the Clean Air Act, including specifically GHG emissions from motor vehicles. Shortly thereafter, the Director of the ARB sent a formal letter to EPA Administrator Johnson reiterating that state's request for a waiver for the revised LEV II program.[5] EPA then opened a formal administrative process that included two public hearings and a written comment period.

On March 6, 2008, EPA denied California's waiver request after determining that California did not need its GHG standards to meet "compelling and extraordinary conditions," one of the three waiver criteria. EPA did not address the other two waiver criteria.

In this denial, EPA said that this was the first "California waiver request for a fundamentally global air pollution problem."[6] EPA identified a number of "fundamental factors" leading to air pollution problems, such as geography, local climate conditions (such as thermal inversions), and density of motor vehicles.[7] And, importantly, EPA said it believed that "Congress had in mind the causal factors of local or regional air pollution problems, not the level of the air pollution per se," when it declared that California must show that it experiences compelling and extraordinary conditions in need of separate vehicle emissions standards. The effect of GHGs however, EPA wrote, were not defined only by these factors. Instead, GHG emissions "from California's cars do not just affect the atmosphere in California, but in fact become one part of the global pool of GHG emissions that affect the atmosphere globally and are distributed throughout the world." In total, the EPA determined that the appropriate criterion to apply was:

> whether the emissions of California motor vehicles, as well as California's local climate and topography, are the fundamental causal factors for the air pollution problem of elevated concentrations of greenhouse gases, and in the alternative whether the effect in California of this global air pollution problem amounts to compelling and extraordinary conditions.

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4 California State Motor Vehicle Pollution Control Standards - Request for Waiver of Preemption Under Clean Air Act Section 209(b) for Greenhouse Gas Emissions (Docket EPA-HQ-OAR-2006-0173). Available at https://www.regulations.gov/docket?D=EPA-HQ-OAR-2006-0173

5 Letter to Stephen L. Johnson, Administrator, USEPA from Catherine Witherspoon, Executive Officer, California Environmental Protection Agency, Air Resources Board (Docket EPA-HQ-OAR-2006-0173). Available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2006-0173-0017.

6 74 Fed. Reg. 12159 (March 6, 2009). Available at https://www.gpo.gov/fdsys/pkg/FR-2008-03-06/pdf/E8-4350.pdf

7 74 Fed. Reg. 12160 (March 6, 2009).

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EPA determined that California did not present sufficient evidence to meet this criterion because, among other reasons, the effects of global climate change would not be extraordinarily felt in California. EPA, therefore, denied this request.

Early in 2009, at the start of the Obama administration, ARB Chairwoman Nichols and California Governor Schwarzenegger both sent letters to the administration requesting that EPA reconsider its waiver denial.[8] Within days, President Obama signed a Presidential Memorandum directing EPA to assess whether the denial was appropriate.[9] By February, EPA had noticed the start of its reconsideration, holding public hearings and accepting comments through spring of 2009.

EPA granted the waiver, reversing the previous administration's finding, on June 30, 2009.[10] EPA Administrator Jackson first laid out an argument for why it was improper to consider the GHG emissions standards separate from the rest of California's vehicle emissions standards included in the LEV II program. The "better approach," EPA stated, was to "review California's need for its new motor vehicle emissions program as a whole to meet compelling and extraordinary conditions, and not to apply this criterion to specific standards."[11] Thus, EPA determined that it was inappropriate to deny the waiver request after having granted previous LEV program waivers.

Furthermore, EPA noted that Section 209 is written to limit the ability of EPA to deny a waiver. EPA must issue a waiver unless it can show that one of three criteria have been met. This interpretation, whereby the presumption of the approval of the waiver request starts in favor of California, is consistent with legislative intent, EPA explained, which was expressly to ''provide the broadest possible discretion [to California] in selecting the best means to protect the health of its citizens and the public welfare.''[12] It notes also that the D.C. Circuit reaffirmed California's unique position, writing that "Congress intended [California] to continue and expand its pioneering efforts at adopting and enforcing motor vehicle emission standards different from and in large measure more advanced than the corresponding federal program. In short, to act as a kind of laboratory for innovation."[13]

Therefore, EPA explained, even if the GHG emissions standards *were* to be considered separately from the rest of the LEV II program, it was the responsibility of opponents of the waiver to demonstrate that California did not need these standards to meet compelling and extraordinary conditions. These opponents, EPA noted, had failed to do so, in light of numerous impacts of climate change. It explained:

> … California has identified a wide variety of impacts and potential impacts within California, which include exacerbation of tropospheric ozone, heat waves, sea level rise and salt water intrusion, an intensification of wildfires, disruption of water resources by, among other things, decreased snowpack levels, harm to high

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8 Letters from Governor Schwarzenegger to President Obama, *and* Commissioner Nichols to Administrator Jackson on January 21, 2009. *Available at* https://insideclimatenews.org/sites/default/files/Schwarzenegger%20and%20Nichols%20Letters.pdf

9 Presidential Memorandum ("EPA Waiver"), Memorandum For the Administrator Of The Environmental Protection Agency. Available at https://obamawhitehouse.archives.gov/the-press-office/2009/01/26/presidential-memorandum-epa-waiver

10 74 Fed. Reg. 32761 (July 8, 2009) https://www.gpo.gov/fdsys/pkg/FR-2009-07-08/pdf/E9-15943.pdf

11 Id.

12 5H.R. Rep. No. 294, 95th Cong., 1st Sess. 301– 302 (1977). See MEMA, 627 F. 2d at 1110–11

13 MEMA, 627 F. 2d at 1111.

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> value agricultural production, harm to livestock production, and additional stresses to sensitive and endangered species and ecosystems. Opponents have not demonstrated that any other state, group of states, or area within the United States would face a similar or wider range of vulnerabilities and risks. In addition, California has submitted information that climate change can impact ozone levels in California due to temperature exacerbation effects. Although other areas of the country are also projected to experience increases in temperatures which may also exacerbate local ozone levels, opponents of the waiver have not demonstrated that California's ozone levels should not be considered compelling and extraordinary conditions.[14]

With this waiver approved, California proceeded with implementing the amended LEV II standards, including the Pavely Standards for GHG emissions. As of 2012, 13 states and the District of Columbia, comprising approximately 40 percent of the light-duty vehicle market, had adopted California's standards.[15]

Current Regulations: Federal GHG Emissions Standards and the California Advanced Clean Cars Program

The 2007 U.S. Supreme Court ruling, *Massachusetts v. EPA*, set in motion a sequence of events that introduced profound changes to the regulation of motor vehicle emissions standards.

In response to the Court's ruling, EPA undertook an extensive scientific review of the impact of these gases on human health and the environment. In late 2009, EPA issued its "Endangerment Finding", which stated that projected concentrations of six GHGs—carbon dioxide, methane, hydroflourocarbons, perfluorocarbons and sulfur hexafluoride—in the atmosphere threaten the public health and welfare of current and future generations. In a separate but related ruling, the Administrator found that the combined emissions of these gases from new motor vehicles contributes to the greenhouse gas pollution, which threatens public health and welfare. These rulings formed the basis for the approval of the first ever explicit federal vehicle GHG emissions standards.

Importantly, these new federal GHG emissions standards were established through the process of a Joint Proposal in 2009 between EPA and NHTSA. In order to avoid having two sets of standards across the country (federal and California), in May 2009, President Obama had reached an agreement with the auto industry, EPA, NHTSA, and California that would create harmonized CAFE fuel economy and GHG standards for cars and light-duty vehicles from 2012 to 2016 at the federal level, with California agreeing to adopt the same standards, as explained further below. These regulations were proposed in September 2009, and, subsequent to the issuance of the Endangerment Finding, the standards were finalized in April 2010, applying starting in model year 2016. In 2012, EPA and NHTSA also finalized rules to set the first GHG emission and fuel efficiency standards for medium- and heavy-duty engines and vehicles.

In 2012, the California ARB worked in coordination with EPA and the NHTSA to develop the Advanced Clean Cars Program. This combined four separate regulations into one program: amended LEV III standards for criteria pollutants emissions, the Pavely GHG emissions standards, ZEV regulations that established targets for total

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14 74 Fed. Reg. 32675 (July 8, 2009)

15 77 Fed. Reg. 62637 (October 15, 2012). Available at https://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf.

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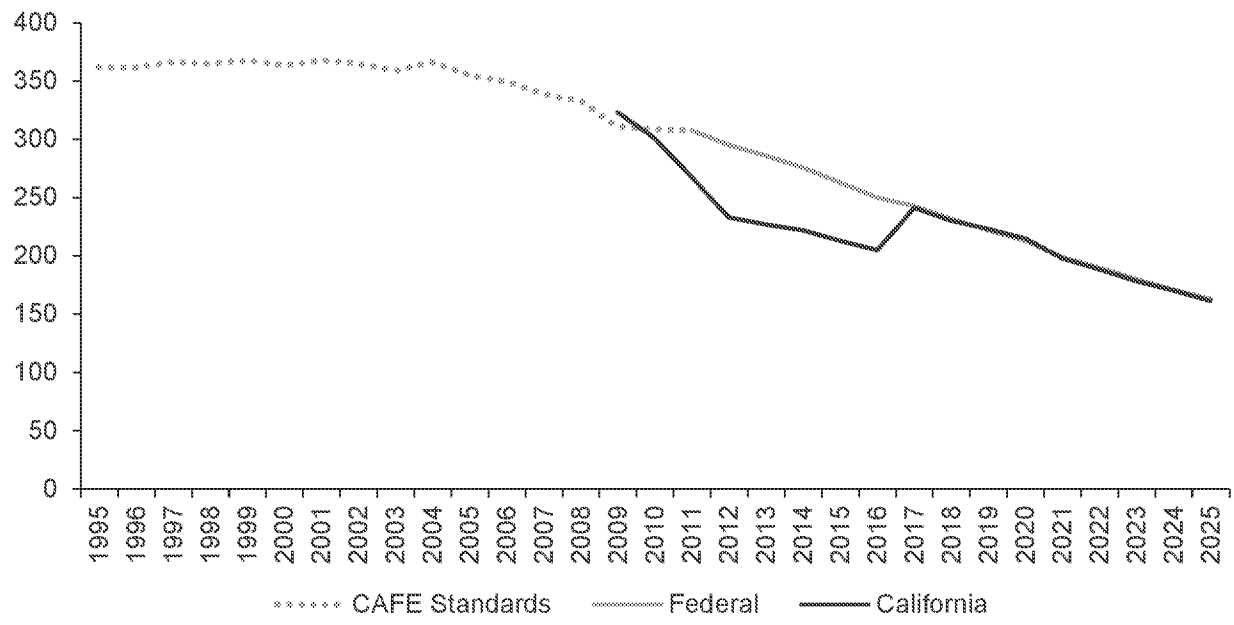
ZEVs purchased in state,[16] and requirements for electric and hydrogen transportation infrastructure improvements (the latter is not subject to federal preemption and does not require a waiver under Section 209). Advanced Clean Cars sets a coordinated set of requirements across all four regulations for model years 2015 through 2025.

ARB submitted a request to EPA for a waiver for the Advanced Clean Cars regulation in June 2012. After public hearing and comment through fall of 2012, EPA approved this waiver request on January 9, 2013.[17] This waiver remains effective for the standards established through 2025. Including California, 13 states and the District of Columbia continue to utilize California's standards.

It is important to note that while previous California criteria pollutant and GHG emissions standards were significantly more stringent than federal standards, the 2010 federal standards and California's ZEV III started a process of convergence between the two programs (see Figure 1). Starting in 2025, both programs set similar fleetwide GHG targets equivalent to 36 miles per gallon in real-world driving conditions (54.5 miles per gallon in testing conditions). This convergence was of critical interest to automakers, who had long argued that navigating differing standards state by state increased costs and complicated vehicle development.

Figure 1 Historic Fleet Average Vehicle GHG Emissions Standards (g CO_2 per mile)



When the ARB adopted the Advanced Clean Cars Program, it committed to a comprehensive "Midterm Review" of the emissions standards (for both criteria pollutants and GHG) and the ZEV regulation. Similarly, EPA was

[16] Note that these ZEV standards are separate from the "ZEV Memorandum of Understanding (MOU)," an agreement among eight states signed in 2013 committing to coordinated action to jointly reach 3.3 million ZEVs on road by 2025. While the ZEV standards under the Advanced Clean Cars program impose regulatory requirements on automakers that sell vehicles into California and Section 177 states, the ZEV MOU identifies joint cooperative actions the signatory states will undertake, and additional actions that individual jurisdictions are considering, to build a robust market for ZEVs. For more information on the ZEV MOU see https://www.zevstates.us/.

[17] 78 Fed. Reg. 2112 (January 9, 2013). Available at https://www.gpo.gov/fdsys/pkg/FR-2013-01-09/pdf/2013-00181.pdf

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required to conduct a Midterm Evaluation of federal light-duty vehicle GHG standards. Both program reviews were set to be conducted in 2016 to review standards for model years 2022 and beyond. Through these review processes, ARB and EPA both determined that their respective standards remain appropriate and that no rulemaking to modify regulations is required. EPA published its Final Determination on January 12, 2017, and ARB released its Advanced Clean Cars Midterm Review Report on January 18, 2017. In its determination, EPA stated that the automotive industry is well positioned to meet the standards at lower costs than previously estimated. The determination also noted that automakers outperformed the standards for the first four years of the program and manufacturers are adopting fuel efficient technologies while vehicle sales have increased for seven consecutive years. However, both ARB and the federal government (the NHTSA) must take rulemaking action to finalize the targets for 2022 and beyond.

Trump Administration: New Uncertainty Regarding California's Waiver

The Trump Administration began signaling in early March its intent to begin rolling back the federal vehicle GHG emission standards.[18] On March 15, 2017, the Administration officially announced its intention to reconsider the Midterm Evaluation of the GHG standards for model years 2022-2025. EPA intends to make a new Final Determination regarding the appropriateness of the standards no later than April 1, 2018. It is expected that in its new Determination, EPA and NHTSA will conclude that the standards for 2022 to 2025 should be less stringent than current standards.

This announcement did not make mention of the appropriateness of California's current waiver, which remains in effect for existing standards through 2025. However, Trump Administration officials have previously questioned whether this waiver would be allowed to stand.[19] Furthermore, there could be increasing pressure from automakers to lower or rollback California's standards in order to avoid recreating a divergence of standards between states adopting California standards and those adopting federal standards.

Legal Challenges

In addition, the midterm review of the emissions standards is the subject of *Alliance of Automobile Manufacturers v. U.S EPA*, filed March 13 at the U.S. Court of Appeals in D.C. On March 15, California, New York, and seven other states petitioned to intervene on behalf of EPA. Oral arguments in this case have not yet been scheduled.

California policymakers and other states that have adopted its vehicle emission standards immediately responded. California Governor Jerry Brown, Senator Kamala Harris, and a group of state attorneys general released statements condemning the order.[20] In addition, on March 22, the environmental agency heads of Connecticut,

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18 https://www.nytimes.com/2017/03/03/us/politics/trump-vehicle-emissions-regulation.html

19 *See*, e.g., http://www.latimes.com/nation/la-na-pol-epa-confirmation-20170118-story.html and https://www.nytimes.com/2017/03/03/us/politics/trump-vehicle-emissions-regulation.html?action=click&contentCollection=us&region=rank&module=package&version=highlights&contentPlacement=1&pgtype=sectionfront&_r=0

20 *See* Letter from Governor Brown to Administrator Pruitt (https://www.gov.ca.gov/docs/3.15.17_Letter_to_EPA.pdf), Letter from Senator Harris to Administrator Pruitt (https://www.harris.senate.gov/sites/default/files/Harris%20to%20Pruitt%20re%20EPA%20Midterm%20Evalu.pdf),

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Delaware, Maryland, Massachusetts, New York, Oregon, Pennsylvania, Rhode Island, Vermont, Washington and the District of Columbia submitted a letter to EPA Administrator Pruitt supporting the MY 2022-2025 Light Duty Vehicle Greenhouse Gas Emission Standards and the California waiver. In this letter, state policymakers noted that any revocation of the waiver or other restriction of California's ability to set its own vehicle emission standards would be "unprecedented" and "undermine our state rights."[21]

The California ARB voted on March 24, 2017 to continue implementing and enforce its existing vehicle emission standards as recommended under the Midterm Review and under its existing waiver. There is no policy or precedent for revoking a waiver that has already been granted. EPA could, however, elect to pursue this course.

Additionally, should California wish to establish more stringent vehicle emission standards, either for model years through 2025 (which the current waiver covers) or for future years, this would likely require an application for a new waiver under Section 209. In that case, EPA could delay review and/or deny the waiver application outright. While California and other state policymakers have vowed to fight any such restriction, any litigation surrounding the waiver could delay the implementation of new standards.

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and Attorney General Kilmartin Joins Coalition of States Opposing President Trump's Vehicle Emission Standards Roll Back (http://www.ri.gov/press/view/29872)

[21] Letter from Environmental Regulators to Administrator Pruitt (http://www.eenews.net/assets/2017/03/23/document_gw_02.pdf)

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About Us

MJB&A provides strategic consulting services to address energy and environmental issues for the private, public, and non-profit sectors. MJB&A creates value and addresses risks with a comprehensive approach to strategy and implementation, ensuring clients have timely access to information and the tools to use it to their advantage. Our approach fuses private sector strategy with public policy in air quality, energy, climate change, environmental markets, energy efficiency, renewable energy, transportation, and advanced technologies. Our international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups and government agencies. Our seasoned team brings a multi-sector perspective, informed expertise, and creative solutions to each client, capitalizing on extensive experience in energy markets, environmental policy, law, engineering, economics and business. For more information, we encourage you to visit our website: www.mjbradley.com.

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MJB&A Issue Brief ■ April 25, 2017

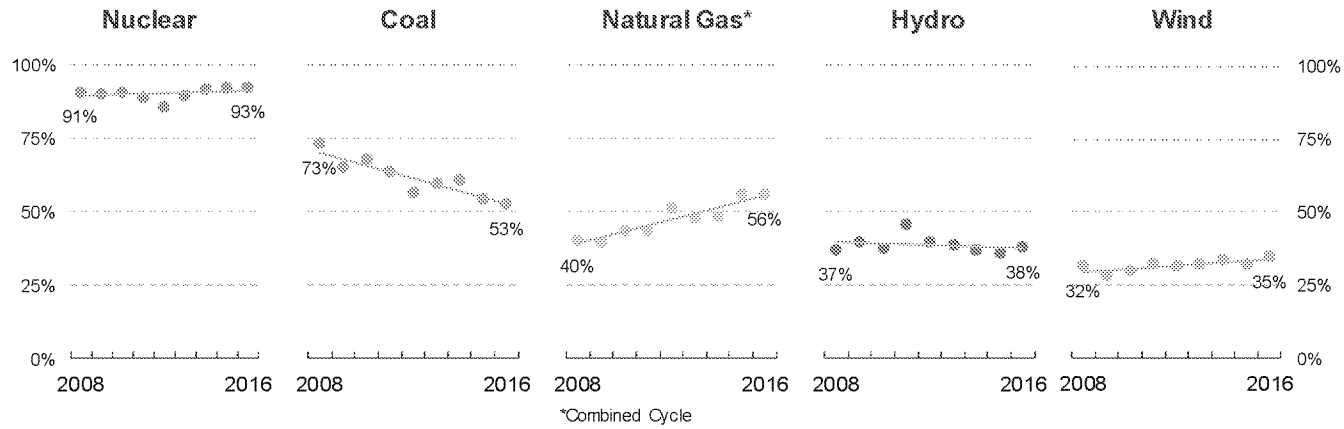
Electric Industry: 2016 Year in Review

In many respects, 2016 could simply be characterized as a year of continuing market trends; on-going changes that have been reshaping the electric power sector in the United States for a decade or more. This would include: (1) a continuing decline in coal-fired power generation; (2) steady growth in natural gas-fired generation; (3) more renewables added to the system, including distributed resources; and (4) limited growth in electricity demand across much of the country (with some notable exceptions). But more than that, 2016 was also a year of major milestones, broken records, and a deepening sense that the industry continues to undergo fundamental change. This article provides an overview of the past year in electric industry.

Natural Gas Takes the #1 Spot

In the competition for market share, natural gas took the number one spot for the first time (on an annual basis) in 2016, overtaking coal as the leading source of electricity generation in the United States. Natural gas accounted for 34 percent of total electricity generation in 2016, while coal accounted for 30 percent. This is the result of a continued decline in coal generation, and a continued increase in gas-fired power generation. In 2016, natural gas combined cycle facilities were running harder than ever, with a nationwide average capacity factor of 56 percent. In PJM, the numbers were even starker. Combined cycle facilities had a 62 percent average capacity factor in 2016, while coal steam units operated at a 33 percent capacity factor in the region.

U.S. Average Capacity Factors by Fuel Type: 2008-2016



Source: U.S. Energy Information Administration. Electric Power Monthly, Tables 6.7A and 6.7B. February 2017

Coal-fired power generation in the United States peaked in the period prior to the Great Recession, between 2005 and 2008. In 2016, coal generation dropped to its lowest levels since the early 1980s. By contrast, gas-fired power generation has continued to increase, fueled by an abundant shale gas resource. Gas-fired generation has increased by 40 percent since 2010. The country has never produced more electricity with natural gas than it did in 2016, and the trend is likely to continue.

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Since the November election, there have been at least seven coal plant retirement announcements, including the largest coal plant in the Western U.S. and almost three gigawatts (GW) of capacity in Ohio. Ohio has close to 10 GW of natural gas-fired power plants in various stages of development, including several large plants that are already under construction. Across the U.S., 13 GW of natural gas-fired generating capacity is scheduled to come online in 2017, including TVA's 1,025 megawatt (MW) Paradise combined-cycle plant in Kentucky, which will replace two of the three units at the older Paradise coal plant.

Coal Unit Retirements Announced Since November 2016

Facility	Owner/Operator	Unit(s)	State	Capacity (MW)	Proposed Retirement Year
A B Brown	Vectren	1-2	IN	490	2024
F B Culley	Vectren	2	IN	90	2024
J M Stuart	Dayton Power & Light	1-4	OH	2,308	2018
Killen	Dayton Power & Light	2	OH	600	2018
Navajo*	Salt River Project	1-3	AZ	2,250	2019
Roanoke Valley	Westmoreland Coal	1-2	NC	209	2017
Elmer Smith	Owensboro Municipal Utilities	2	KY	260	2023

*Efforts are being made to keep the plant and associated mine in operation by finding a buyer for the facility.

Source: MJB&A Coal Retirement Tracker. MJB&A maintains a database of coal plant retirement announcements throughout the U.S.

Renewables Continue to Track Upward

Renewable energy development has also been breaking records over the past year and into the new year. In 2016, wind capacity surpassed hydroelectric capacity with more than 80 GW of cumulative additions. In February and March 2017, both the Southwest Power Pool (SPP) and ERCOT (Texas) satisfied more than 50 percent of their load with wind resources for a short period. SPP became the first regional transmission organization (RTO) in North America to serve more than 50 percent of its load with wind resources on February 12, 2017. In response, the Vice President of Operations said: "Ten years ago, we thought hitting even a 25 percent wind-penetration level would be extremely challenging, and any more than that would pose serious threats to reliability…Now we have the ability to reliably manage greater than 50 percent wind penetration. It's not even our ceiling." ERCOT broke the 50 percent mark in March 2017. In the Upper Midwest, Xcel Energy recently announced that it would be adding 600 MW of wind in South Dakota, 100 MW in North Dakota, and 100 MW in Minnesota.

2016 was also a record-breaking year for solar installations. According to the Solar Energy Industries Association, the U.S. solar industry added almost 15 GW of solar capacity in 2016, nearly doubling the prior installation record set in 2015. Most of the capacity built was utility-scale projects, which are significantly more cost-effective than small-scale residential projects. Construction activity was concentrated in a relatively small number of states. California was, by far, the leading installer of solar energy projects with more than 5 GW of additions, while Utah, Georgia, Nevada, and North Carolina all added about 1 GW of capacity.

A big part of what has been driving the growth in renewables has been the federal tax incentives. The production tax credit (PTC) for wind and the solar investment tax credit (ITC) were extended at the end of 2015, significantly lowering the delivered price of energy for qualifying projects. The tax credits include an eventual decline in value for both technologies with the PTC for wind expiring in 2020 and the ITC for large-scale solar declining from 30 percent to a permanent 10 percent and expiring for residential projects in 2022.

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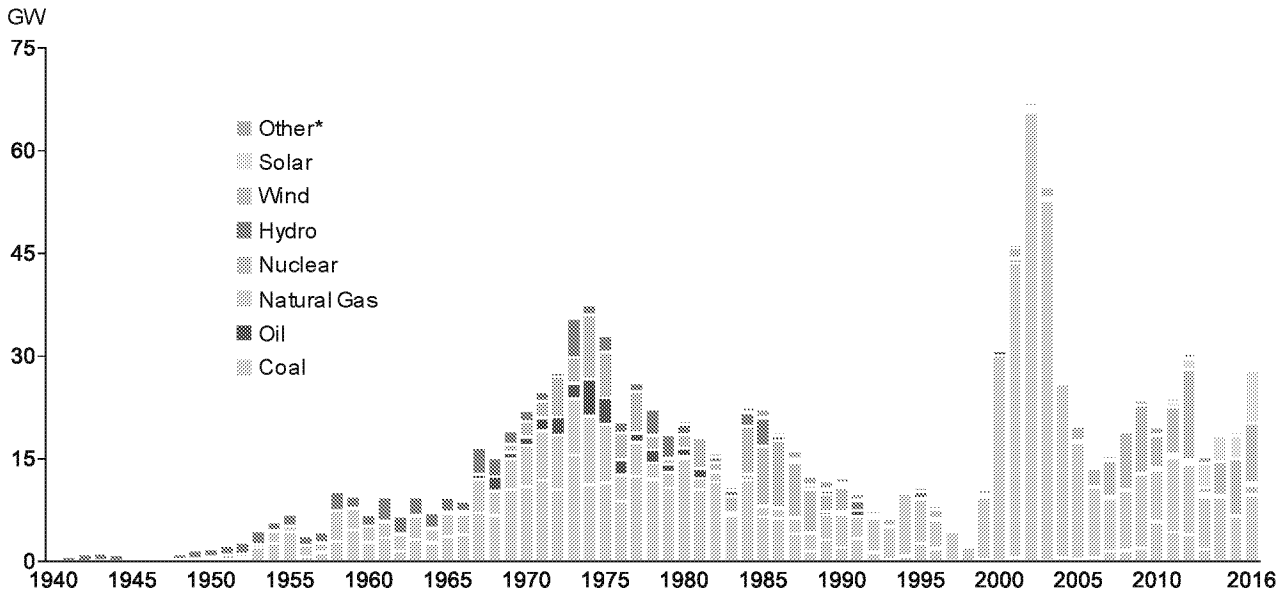
Demand for renewable energy has been expanding beyond electric utility companies, seeking to diversify their supply portfolios or comply with state renewable mandates. For example, in 2016, Lockheed Martin signed a power purchase agreement for 30 MW of solar power to hedge against increases in energy costs. According to the American Wind Energy Association (AWEA), 24 percent of the wind capacity installed in 2016 (1,953 MW) was under long-term power purchase agreements with corporate and other non-utility customers.

Together, wind and solar accounted for about 60 percent of capacity additions in 2016, as illustrated by the chart below. The Watts Bar 2 nuclear facility also came online in 2016; the first U.S. reactor to enter service in 20 years. Natural gas accounted for about 33 percent of new capacity additions in 2016.

U.S. Electric Generating Capacity by In-Service Year: 2016



*Other includes renewable resources such as geothermal, biogenic municipal waste, biomass, and wood derived fuels, as well as other fuel types

Sources: EIA; MJB&A analysis

Low Commodity Prices Put Strain on Organized Markets

Natural gas prices in the U.S. have continued to remain low and 2016 was no exception. Natural gas production declined in 2016 for the first time since 2005, but overall supply and demand has kept prices low. In fact, the Henry Hub gas price (average annual) was at its lowest level since 1999, despite a recovery in prices through the second half of the year. Warmer than normal weather throughout much of the United States this past winter and a robust level of gas production have combined to dampen prices. For the first time since storage data have been collected, EIA reported a net injection of natural gas in the month of February. Net injections of natural gas into storage would not typically occur until at least April when demand starts to subside after the winter heating season.

The result of the low natural gas prices and changes in the fuel mix has been significant financial pressures on competitive power generators in the nation's organized power markets. For example, the PJM Market Monitor reported that the average real-time electricity price in 2016 was 19 percent below the previous year and "the lowest since the competitive wholesale market commenced operation in 1999". ERCOT also experienced record low prices in 2016. In response to the low price environment, S&P Global Ratings warns that "[t]he duration and

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extent of softness in ERCOT power prices has exceeded our previous expectations and now suggests a longer-term, secular challenge, which isn't likely to allay credit concerns in the near term."

The low-price environment has led some companies to exit the competitive power business, and advocate a return to regulated power markets. For example, in November 2016, FirstEnergy announced that it would be transitioning to a fully regulated utility company, and has since announced the sale of several competitive natural gas and hydroelectric power stations. FirstEnergy and AEP have also been advocating legislation that would return Ohio to a regulated power market. Separately, FirstEnergy has also been seeking income support, in the form of zero-emission credits, for its nuclear power plants in Ohio, to facilitate the sale of the assets. New York and Illinois have approved similar programs for nuclear plants that were at risk closure. FERC overturned an earlier effort by the state of Ohio to subsidize AEP and FirstEnergy coal and nuclear plants, using power purchase agreements.

Looking Forward

The electric power system in the United States has always been shaped by a mix of public policy, commodity prices, and technology innovations. Current market trends and state-level policies point to continued growth in the use of natural gas and renewable energy over the coming years. In 2016, New York and Oregon both adopted renewable energy standards targeting 50 percent renewables; California adopted a 50 percent renewable standard in 2015. Expect continued debate over the treatment of nuclear power plants challenged by low wholesale power prices. Nuclear plants supplied about 20 percent of the nation's electricity and 60 percent of zero-emissions generation in 2016. The Trump Administration has expressed strong support for the coal industry, but even coal industry executives acknowledge that they are facing strong headwinds given the realities of the energy markets.

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About Us

MJB&A provides strategic consulting services to address energy and environmental issues for the private, public, and non-profit sectors. MJB&A creates value and addresses risks with a comprehensive approach to strategy and implementation, ensuring clients have timely access to information and the tools to use it to their advantage. Our approach fuses private sector strategy with public policy in air quality, energy, climate change, environmental markets, energy efficiency, renewable energy, transportation, and advanced technologies. Our international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups and government agencies. Our seasoned team brings a multi-sector perspective, informed expertise, and creative solutions to each client, capitalizing on extensive experience in energy markets, environmental policy, law, engineering, economics and business. For more information, we encourage you to visit our website, www.mjbradley.com.

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Message

From: McLamb, Marguerite [McLamb.Marguerite@epa.gov]
Sent: 7/30/2019 1:47:56 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
CC: Ashley, Jackie [Ashley.Jackie@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]; Fruh, Steve [Fruh.Steve@epa.gov]
Subject: Re: CONGRESS - Due Tuesday - Quick turn-around request: Methane actions

Thanks, all!

****

Marguerite E. McLamb
Policy Advisor
Sector Policies and Programs Division
Office of Air Quality Planning & Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711
Phone (office): (919) 541-7858
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Fax: (919) 541-4991
mclamb.marguerite@epa.gov

On Jul 30, 2019, at 9:38 AM, Hambrick, Amy <Hambrick.Amy@epa.gov> wrote:

> Thanks Jackie and Karen. No comments on Policy blurb.
>
> Amy
>
> Amy Hambrick
> U.S. Environmental Protection Agency
> (919)541-0964
>
> ---
>
> **From:** Ashley, Jackie <Ashley.Jackie@epa.gov>
> **Sent:** Tuesday, July 30, 2019 8:56 AM
> **To:** Marsh, Karen <Marsh.Karen@epa.gov>; McLamb, Marguerite <McLamb.Marguerite@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>
> **Cc:** Fruh, Steve <Fruh.Steve@epa.gov>
> **Subject:** RE: CONGRESS - Due Tuesday - Quick turn-around request: Methane actions
>
> Good point, Karen. Let's strike the highlighted sentence.
>
> ---
> Jackie Ashley - US EPA - Office of Air Quality Planning and Standards - 919-541-7664 – ashley.jackie@epa.gov
>
> ---
>
> **From:** Marsh, Karen <Marsh.Karen@epa.gov>
> **Sent:** Tuesday, July 30, 2019 8:50 AM
> **To:** McLamb, Marguerite <McLamb.Marguerite@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>; Ashley, Jackie <Ashley.Jackie@epa.gov>
> **Cc:** Fruh, Steve <Fruh.Steve@epa.gov>
> **Subject:** RE: CONGRESS - Due Tuesday - Quick turn-around request: Methane actions

Ex. 5 Deliberative Process (DP)

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: McLamb, Marguerite
Sent: Monday, July 29, 2019 5:34 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>
Cc: Fruh, Steve <Fruh.Steve@epa.gov>
Subject: FW: CONGRESS - Due Tuesday - Quick turn-around request: Methane actions

Hi, folks – could you take a look at the request from OCIR below and get back to PACS by noon? Feel free to respond directly to Jackie and cc me.
Thanks!
Best,
Marguerite

From: Ashley, Jackie <Ashley.Jackie@epa.gov>
Sent: Monday, July 29, 2019 5:08 PM
To: McLamb, Marguerite <McLamb.Marguerite@epa.gov>
Subject: CONGRESS - Due Tuesday - Quick turn-around request: Methane actions

Marguerite –
See the request from OCIR below. I'm checking whether they are only interested in oil and gas, or also landfills. I went ahead and pulled something together on both. Could SPPD please review/edit by **noon on Tuesday**?

Thanks,
Jackie

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Jackie Ashley - US EPA - Office of Air Quality Planning and Standards - 919-541-7664 – ashley.jackie@epa.gov

From: Thundiyil, Karen <Thundiyil.Karen@epa.gov>
Sent: Monday, July 29, 2019 3:13 PM
To: Ashley, Jackie <Ashley.Jackie@epa.gov>; Cyran, Carissa <Cyran.Carissa@epa.gov>
Subject: Quick turn-around request: Methane actions

Hi Jackie and Carissa,

Last week Administrator Wheeler and Rep Roger Marshall met. A few minutes ago Christian Roderick told me that the Rep is interested in EPA methane regulation. Christian has asked for a list of completed (last 12 months) and upcoming methane regulations (through 2020). He asked for it by COB today. I said tomorrow is more reasonable. Can you send me a list today or tomorrow? The list should include the name of the action, short description, status (completed, at OMB, under development at Agency, etc) by tomorrow? If it helps I can write up the ones that are at OMB now.

Let me know.

Thanks,

Karen.

Appointment

From: Dominguez, Alexander [dominguez.alexander@epa.gov]
Sent: 10/19/2017 12:36:13 PM
To: Dominguez, Alexander [dominguez.alexander@epa.gov]; Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]

Subject: Encana
Attachments: Encana.pdf
Location: 5415 WJCN

Start: 11/8/2017 7:00:00 PM
End: 11/8/2017 7:45:00 PM
Show Time As: Busy

Meeting with Shea Loper (Manager of Government Relations, Encana) to discuss air monitoring and methane.
Traveling in from Denver.
To: Dominguez, Alexander; Gunasekara, Mandy

encana

May 15, 2017

Administrator Scott Pruitt
United States Environmental Protection Agency
Office of the Administrator, 1011A
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

RE: Evaluation of Existing Regulations, Docket ID No. EPA-HQ-OA-2017-0190

Dear Administrator Pruitt:

Encana Oil & Gas (USA) Inc. ("Encana") appreciates the opportunity to provide comments on the Environmental Protection Agency's ("EPA's") regulatory reform initiative under President Trump's Executive Order 13,777 *Enforcing the Regulatory Reform Agenda*. This effort along with the President's Executive Order 13,783 on *Promoting Energy Independence and Economic Growth* demonstrates a commitment to promoting responsible American energy production under an effective and efficient regulatory framework. We welcome a healthy dialogue on reforming regulations to establish a system that protects our environment while also utilizing our abundant natural resources and stimulating economic growth. While EPA regulations impact many aspects of our operations, we focused Encana's comments on the most significant areas for reform.

Encana has significant operations and investment in the United States, which are impacted by the rules and regulations imposed by EPA. Encana has acreage in Texas, Colorado, New Mexico, and Wyoming and employs over 1,000 people throughout these states. As of December 31, 2016 Encana had 5,413 net wells in the US that produced 417 Mmcf per day of natural gas and 94,900 barrels per day of liquids.

The U.S. oil and natural gas industry is highly innovative. Between 2000 and 2014, the industry invested $90 billion in zero and low emissions technologies. According to EPA's own data, U.S. oil and natural gas producers have reduced methane emissions from associated gas venting and flaring by over 20% compared with 1990 levels despite dramatic increases in production over the same time.[1] Advancements in drilling technologies continue to reduce our operational footprint, improve safety, and minimize our impact on the environment. Encana will continue to improve not only because it inherently makes economic sense to optimize oil and gas production, but also because we value environmentally safe and responsible operations.

By revising or rescinding rules consistent with the notice and comment requirements under the Administrative Procedures Act (APA) and with greater public input and transparency, EPA can forge a more innovative and effective regulatory environment. This framework can withstand judicial scrutiny and endure changing political winds, which will help provide the certainty needed to improve environmental performance over the long-term. Too often in recent years, EPA rushed rulemakings and policy development without truly understanding the technical nuances of our operations. The result is cumbersome, overly prescriptive rules that hinder economic growth and stifle environmentally beneficial

[1] https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf

Encana Oil & Gas (USA) Inc.

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innovation. Encana urges EPA to take a collaborative approach that recognizes the role of states in implementing federal environmental laws, the unique factors and challenges in different parts of the country, and the value of industry's technical expertise.

We also encourage EPA to consider procedural changes to how it develops regulations. These procedural changes could include industry-agency engagement prior to rule drafting and proposal so that ideas and potential solutions can be exchanged in advance of the notice and comment period. Such engagement and exchange of ideas will aid in sensible, reasonable, and data-driven regulation that respects the statutory authority provided to EPA by Congress.

In Encana's opinion, the regulatory framework governing air quality across the oil and natural gas industry requires the most significant attention. Despite the dramatic reduction in industry emissions discussed above, we have experienced a new and overreaching federal air quality regulatory regime. In passing a steady stream of rules, EPA too often ignored data, shortcut due process, exceeded its Clean Air Act authority, and finalized regulations that were technically untenable and economically unsound. These and other flaws provide the necessary legal justification under current case law for EPA to revisit these rules, draw different conclusions, and change them in fundamental ways.

In recent years, EPA also implemented and enforced new regulations in a manner that duplicated and often conflicted with properly delegated state regulatory programs. The result is an overly burdensome and confusing regulatory environment, which has discouraged growth and innovation, and prioritized bureaucracy over actual improvements to air quality.

Reconsideration of New Source Performance Standards (NSPS), Subpart OOOOa

In 2012, EPA ushered in the most expansive air quality regulatory regime governing the oil and natural gas industry in nearly 30 years. Known as "Quad O," these broad rules imposed emission controls and other requirements on virtually every aspect of the upstream and midstream oil and natural gas segment. Following EPA's source category listing in 1979[2] until 2012, federal regulation focused almost exclusively on controlling emissions at natural gas processing plants. The Quad O rules brought thousands, if not hundreds of thousands, of new facilities under federal regulation. Remarkably, EPA did not undertake a separate rulemaking to update or expand the 1979 source category. This omission violates EPA's legal obligation under section 111(b) of the Clean Air Act. Without a clear picture of the newly expanded source category, the result is a clunky and rigid, one-size-fits-all program (Quad O) that imposes substantial costs and questionable environmental benefits. We encourage EPA to revisit its prior decision to expand the source category.

Despite claiming "significant environmental co-benefit by reducing methane emissions" with Quad O in 2012, EPA shortly thereafter initiated another rulemaking targeting methane emissions, known as "Quad Oa." This rule was finalized in 2016. Once again, EPA failed to first engage in a separate rulemaking process to determine whether and how methane emissions from this sector may (or may not) contribute significantly to the endangerment of public health or welfare. This "significant contribution" finding is a legal pre-requisite to regulation of any pollutant, including methane, under section 111(b) of the Clean Air Act. Although Quad Oa is currently in effect, EPA's failure to make a "significant contribution" finding calls into question the fundamental legality of this rule. Encana encourages EPA to review this issue during its rule review.

[2] *See* 44 Fed. Reg. 49,223 (Aug. 21, 1979)

Further, Quad Oa presents numerous implementation issues. These include: the expansive definition of "modification" as it affects the applicability of the Leak Detection and Repair (LDAR) program at compressor stations; the lack of flexibility related to technology; inconsistency with existing state programs; onerous and unnecessary recordkeeping, reporting, and professional engineer (PE) certification requirements; the inappropriate application of the "once in always in" policy to new sources of criteria (as opposed to *hazardous*) pollutants; flawed pneumatic pump requirements; and EPA's decision, without any supporting data, to not exempt low production wells. EPA's recent announcement to stay the compliance date for 90 days as the agency reviews the new requirements is pragmatic and necessary.

Around the same time the previous Administration proposed updates to the NSPS, it also proposed new Control Technique Guidelines (CTGs) for existing sources of Volatile Organic Compounds (VOC) from oil and natural gas facilities in Ozone nonattainment areas. The CTGs were finalized in October 2016. The CTGs should be suspended or withdrawn until the NSPS issues are resolved and determinations can be made on the appropriateness, and specifically the cost-effectiveness, of the technologies, controls, and work practice standards being applied under the CTGs to existing sources.

Cost-Benefit Analysis and the Use of Social Cost of Carbon/Methane

Perhaps more so than any other federal environmental statute, robust cost-benefit analyses are critical when it comes to regulation under the Clean Air Act. Sources of air emissions vary greatly across industry segments and across different types of facilities even within an industry segment. For this reason, the Clean Air Act, not to mention basic principles of good government, requires regulations to be cost-effective—meaning the cost per ton of pollutant reduced is reasonable and adequately justified. In recent years, EPA has made cost-effectiveness decisions for the oil and gas industry that were not fully justified by, or even flatly contradicted, the data on the record. For example, the cost-effectiveness of LDAR programs differ widely depending on a facility's location (rural vs. developed area), composition of gas (wet vs. dry gas), age (new vs. existing), and the frequency of inspection. Yet, the rule does not distinguish or allow for flexibility on any of these grounds. Both Quad O and Quad Oa are replete with similar examples.

With respect to the regulation of greenhouse gases (GHGs), the Social Cost of Carbon (SCC) and Methane (SCM) were developed to account for a panoply of anticipated "social" costs to society associated with marginal increases in GHG emissions (*e.g.*, rising health care, property damage, higher food prices etc.). EPA used the resulting metric—a $/ton of carbon dioxide equivalent emitted—to prop up virtually every major air quality rule over the past several years, including Quad Oa, the Bureau of Land Management's (BLM's) Venting and Flaring Rule, and the Clean Power Plan. We applaud the administration's quick recognition that the SCC/SCM is a deeply flawed economic methodology.[3] We support the President's directive to withdraw the use of SCC/SCM in rulemakings.

[3] A bipartisan group of respected economists detailed several of the prominent flaws with this approach, including the fact benefits of GHG emissions reductions are extrapolated globally while the costs of such regulation are born only domestically (https://www.forbes.com/sites/susandudley/2016/02/09/how-much-will-climate-change-rules-benefit-americans/#40e5cbd663ca).

encana

Ozone

The regulation of ozone is not unique to the oil and natural gas sector, but like many other parts of the economy, an ever more stringent federal standard carries potentially devastating impacts for the future of oil and natural gas production. In developing a reform strategy on the ozone issue, we encourage EPA to consider the numerous nuances and complexities involved with this issue. Ozone formation is highly dependent on geographic location, local and regional meteorology, the mix and prevalence of contributing sources, time of year, and numerous other variables. As a result, addressing this vexing issue will take a similarly variable and flexible approach.

Furthermore, EPA is tasked with implementing two separate ozone standards. This creates confusion and inefficiency, in addition to the enormous cost to implement dual standards and competing timelines. Evidence shows that ambient ozone levels were declining under the 2008 standard, and public health was already protected within an adequate margin of safety. EPA agreed that ozone levels would keep falling as the 2008 ozone standard was implemented. Contrary to EPA's finding of diminishing ozone levels, it implemented a new standard in 2015 that created overlapping timelines, unnecessary controls, and an inefficient system of emissions reduction. To address this confusion, EPA should reconsider the 2015 ozone standards based upon the best available science, suggesting the new standard is unnecessary.

We encourage EPA to be practical and flexible in its interpretation of the various statutory ozone tools available to the agency such as: section 179B of the Clean Air Act, which allows areas to account for international transport of ozone; section 182, which allows areas to obtain a waiver for reducing Nitrogen Oxide (NOx) if a demonstration can be made that doing so would not improve or actually produce more ozone; and section 319(b), which allows EPA to consider exceptional events and their contribution to ozone non-attainment. Simply put, EPA has been rigid in its approach and interpretation of these, and other, statutory tools. We believe now is the time to overhaul how the agency interprets and uses its ozone authority under the Clean Air Act.

Enforcement/State Consultation

The prior Administration coordinated an aggressive enforcement approach towards the oil and natural gas industry. Although the core and fundamental underpinning of the Clean Air Act is "cooperative federalism," EPA's approach failed to respect state regulatory programs and authority. For the oil and natural gas industry, this heavy-handed approach was reflected most starkly through broad section 114 information requests and EPA "overfiling" (*i.e.*, taking over enforcement from the states). These actions culminated in punitive federal consent decrees that bore little resemblance to actual legal requirements. EPA's policy of "regulation through enforcement" chose winners (non-fossil fuel energy) and losers (oil and gas), significantly discouraged and curtailed progress, was out of step with existing and robust state programs, and contradicted EPA's own data showing emissions decreasing through improved operations and technology. Through this federal command and control approach, EPA stifled the kind of technological innovations that have been responsible for improving emissions, and which Encana and others in the industry will need to employ in the coming years to realize further reductions.

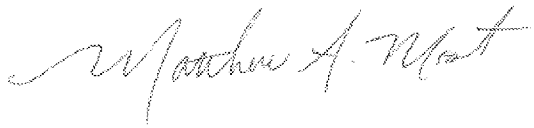
Furthermore, respect for the cooperative federalism framework of the Clean Air Act is particularly important for the regulation (and enforcement) of the oil and gas industry. Unlike refineries or power plants, which are relatively homogenous, the development and production of oil and natural gas varies drastically depending on location. Whether the issue is ozone, flaring, or fugitive emissions, each geographic region presents its own unique characteristics and challenges. Thus, it is critically important that states play a prominent role in how the industry is regulated. We are encouraged that this

encana

Administration appears to understand the critical importance of state consultation, coordination, and deference where appropriate. And we urge EPA to look for lasting solutions that restore the cooperative federalism intent and structure to federal implementation of the Clean Air Act.

Encana appreciates the opportunity to provide its comments to EPA and the Administration as it embarks on, what we are confident will be a significant, meaningful, and thoughtful regulatory reform effort. Please feel free to contact me should you have any questions.

Sincerely,



Matthew Most
Vice President, Government Relations

Appointment

From: Adm14Pruitt, Scott [adm14pruitt.scott@epa.gov]
Sent: 4/28/2017 2:39:17 PM
To: Adm14Pruitt, Scott [adm14pruitt.scott@epa.gov]; Nishida, Jane [Nishida.Jane@epa.gov]; Bennett, Tate [Bennett.Tate@epa.gov]; Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]; Vance, Eric [Vance.Eric@epa.gov]

Subject: Meeting with Canadian Association of Petroleum Producers (CAPP)
Attachments: CAPP bios.docx; Adm Briefing for Canada APP May 2017 dft2.docx
Location: Administrators Office

Start: 5/2/2017 8:00:00 PM
End: 5/2/2017 8:30:00 PM
Show Time As: Busy

Topic: CAPP is the Canadian equivalent of API, and CAPP member companies produce 85% of Canada's oil and natural gas. The purpose of the meeting would be for the CAPP officials to gain a better understanding of the environmental regulatory rollback in the United States relating to the oil and gas sector
Location: Administrator's Office
Attendees: David Wilkins, Justin Meyers, CAPP's CEO Tim McMillan will be accompanied by CAPP's incoming Board of Governors Chair Rob Dutton (President, Devon Canada) and CAPP's current Board of Governors Chair Mike Gatens (CEO, UGR Blair Creek).
Staffing: Jane, Tate
POC: David Wilkins: david.wilkins@nelsonmullins.com

U.S. ENVIRONMENTAL PROTECTION AGENCY
Washington D.C.

Briefing Document for Administrator Pruitt

MEETING WITH THE CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

DATE: May 2, 2017
LOCATION: Administrator's Office
MEETING TIME: 4:00 PM

I. PURPOSE

YOU will be meeting with the senior leadership of the Canadian Association of Petroleum Producers (CAPP). CAPP officials have asked to discuss EPA's priorities for reducing unnecessary regulatory burdens associated with the development of the oil and gas sector, as called for under the Executive Order on Promoting Energy Independence and Economic Growth (Executive Order 13783).

II. BACKGROUND

The Canadian Association of Petroleum Producers (CAPP) is the voice of Canada's upstream petroleum industry, a role similar to the American Petroleum Institute (API) in the U.S.

- CAPP member companies produce 85% of Canada's natural gas and crude oil, with revenues of about $120 billion a year, and CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry.
- CAPP's goal is to enhance Canada's prosperity by enabling responsible growth of Canada's upstream oil and natural gas industry.
- CAPP advocates for and enables economic competitiveness and safe, environmentally and socially responsible performance.

EPA announced that it is reviewing the 2016 Oil and Gas New Source Performance Standards (NSPS) and, if appropriate, will initiate reconsideration proceedings to suspend, revise or rescind the rule.

- The agency announced its plans in a Federal Register notice published April 4, 2017.
- If the agency's review concludes that suspension, revision or rescission of the NSPS may be appropriate, it will follow a rulemaking process that is transparent, follows proper administrative procedures, includes appropriate engagement with the public, employs sound science, and is firmly grounded in the law.

III. KEY ASKS OR MESSAGES: *N/A*

IV. PARTICIPANTS

<u>CAPP</u>

- Tim McMillan, CAPP CEO
- Rob Dutton, President, Devon Canada, [CAPP's incoming Board of Governors Chair]
- Mike Gatens, CEO and Director, Unconventional Gas Resources [CAPP's current Board of Governors Chair]

- David Wilkins, Partner, Nelson Mullins Riley & Scarborough LLP, [Former U.S. Ambassador to Canada]
- Justin Meyers, Policy Advisor Nelson Mullins Riley & Scarborough LLP

EPA

- YOU
- Mandy Gunasekera
- Jane Nishida, OITA

V. AGENDA: No formal agenda.

VI. PRESS: This is a closed meeting with no press.

VII. ATTACHMENT:

- Biographies: Tim McMillan, Rob Dutton, Mike Gatens, David Wilkins
- One-Pager: Internal EPA Brief on Oil & Gas Reg Review

EPA Staff Contact: Jane Nishida, Office of International and Tribal Affairs, 202-564-1531

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ATTACHMENT: BIOGRAPHIES

Tim McMillan, President and CEO
Canadian Association of Petroleum Producers

Tim McMillan was appointed President and CEO of the Canadian Association of Petroleum Producers (CAPP) on October 1, 2014. The Saskatchewan native is responsible for leading activities in education and communications as well as policy and regulatory advocacy on behalf of CAPP member companies.

Tim grew up on a family farm near Lloydminster, where the McMillan family first homesteaded more than a century ago. After earning an economics degree from the University of Victoria, he traveled and worked overseas as an Information Technology professional. He later returned to the family farm and founded and operated an oilfield services company.

In 2007, Tim was elected as a Saskatchewan Party MLA in the riding of Lloydminster. From 2010 until his appointment as President of CAPP, Tim held several strategic cabinet portfolios in the Government of Saskatchewan, including minister of energy and resources and minister of rural health. Tim recently moved to Calgary where he lives with his wife and their two daughters.

Rob Dutton, President
Devon Canada

Rob Dutton was named President of Devon Canada and Senior Vice President of Devon's Canadian Operations in July 2014. His previous roles include vice president of Capital Projects, vice president of Facilities and general manager of Thermal Facilities.

Devon Energy Corp. engages in the exploration, development, and production of oil, natural gas and natural gas liquids. It operates through the U.S. and Canada. The company was founded by J. Larry Nichols and John W. Nichols in 1971 and is headquartered in Oklahoma City, OK.

Prior to joining Devon in 2007, Dutton worked in roles of increasing responsibility with several multinational oil and gas producers, including Anadarko and ConocoPhillips. He holds a bachelor's degree in chemical engineering from the University of Saskatchewan. He is a member of the Association of Professional Engineers, Geologists and Geophysicists.

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J. Michael Gatens, Chief Executive Officer and Director
Unconventional Gas Resources

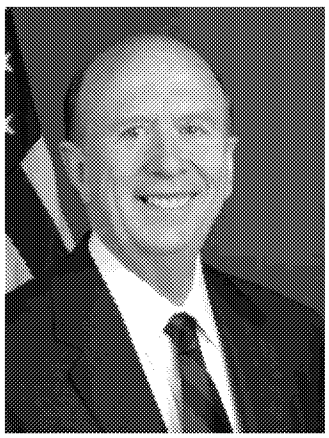
Mr. Gatens has served on the Canadian Association of Petroleum Producers (CAPP) Board of Governors from 2004-2008, and 2012-present. In December 2014, Mike was appointed vice chair at CAPP and he assumed the chair in April 2016. Mike was the founding Chairman of the Canadian Society for Unconventional Gas, is a registered professional engineer in Texas and Alberta, and has been active in several joint industry / government / stakeholder initiatives, receiving the Alberta Centennial Medal in 2005.

Work Experience -- 36 years of oil and gas experience

- CEO, Co-Founder, Unconventional Gas Resources, Calgary, Alberta
- Chairman, Quicksilver Resources Canada, Calgary, Alberta
- Chairman and Co-Founder, MGV Energy Inc., Calgary, Alberta
- Director and Vice-President, S. A. Holditch and Associates, Inc., College Station, Texas and Pittsburgh, Pennsylvania
- Petroleum Engineer, Bass Enterprises Production Company, New Orleans, Louisiana, Fort Worth, Texas & Oklahoma City, Oklahoma

- B.Sc., Petroleum Engineering, Texas A&M University, 1980
- M.Sc., Petroleum Engineering, Texas A&M University, 1987

David H. Wilkins, Partner
Nelson Mullins



Appointed Ambassador to Canada by President George W. Bush, Ambassador Wilkins helped to resolve the softwood lumber trade dispute, with support that included most of the Canadian lumber industry. In addition to the softwood lumber dispute, Wilkins addressed a number of other issues including the Northwest Passage, Rendition, the North American Free Trade Agreement (NAFTA) and Canada's role in Afghanistan.

Ambassador Wilkins served 25 years in the South Carolina House of Representatives, including as the first Republican speaker of a state legislature in the South since Reconstruction, a position which he retained for 11 years, before his appointment as Ambassador to Canada.

In his 25 years in the South Carolina Legislature, David Wilkins was on the cutting-edge of most major reform initiatives. He wrote or co-sponsored the legislation on welfare reform, property tax relief, education accountability, LIFE scholarships, judicial reform, government restructuring, and truth-in-sentencing. He was also instrumental in crafting South Carolina's historic ethics bill and played a key role in the fight to ban video gambling. He was also a central figure in the relocation of the Confederate battle flag from atop the State Capitol Building to the Confederate Memorial.

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ATTACHMENT: INTERNAL EPA BRIEF ON OIL & GAS REG REVIEW

FOR INTERNAL USE ONLY

For May 2 meeting with the Canadian Association of Petroleum Producers

Status of the 2016 Oil and Gas New Source Performance Standards for New, Modified and Reconstructed Sources
(sometimes referred to as the Methane NSPS)

Executive Order: On March 28, 2017, President Trump signed the Executive Order on Promoting Energy Independence and Economic Growth (Executive Order 13783). The purpose of the Executive Order is to facilitate the development of U.S. energy resources-- including oil and gas--and to reduce unnecessary regulatory burdens associated with the development of those resources.

Review of the NSPS: Following through on the Executive Order, EPA announced that it is reviewing the 2016 Oil and Gas New Source Performance Standards (NSPS) and, if appropriate, will initiate reconsideration proceedings to suspend, revise or rescind the rule.

- The agency announced its plans in a Federal Register notice published April 4, 2017.
- If the agency's review concludes that suspension, revision or rescission of the NSPS may be appropriate, it will follow a rulemaking process that is transparent, follows proper administrative procedures, includes appropriate engagement with the public, employs sound science, and is firmly grounded in the law.

Reconsideration of certain aspects of the NSPS: Continuing to follow through with the President's Energy Independence Executive Order, EPA announced on April 18, 2017, its intent to reconsider certain aspects of the 2016 NSPS, in response to four administrative petitions for reconsideration.

- As a result of the reconsideration, the agency intends to exercise its authority under the Clean Air Act to issue a 90-day stay of a June 3, 2016 compliance date for the fugitive emissions monitoring requirements in the rule. Sources will not need to comply with these requirements while the stay is in effect.
- Under the Clean Air Act [Section 307(d)(7)(B)], the EPA Administrator is required to convene a proceeding for reconsideration of a rule if a person raising an objection "can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule"
- As part of the reconsideration process, EPA will provide an opportunity for notice and comment on the issues raised in the four petitions that meet this standard in the law, as well as any other matter the agency believes will benefit from additional comment.

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Message

From: Dominguez, Alexander [dominguez.alexander@epa.gov]
Sent: 10/9/2018 5:05:09 PM
To: Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]
Subject: FW: LA Assn of Business and Industry
Attachments: ajdREV+Louisiana Backgrounder Draft V1.docx

Attached is the draft backgrounder. Per a follow up with Tate I also included ACE. Very minor edits to all language. I included the detailed fact sheet on the Technical Amendments, although this can of course be omitted if you think it is too in depth.

From: Bennett, Tate
Sent: Tuesday, October 9, 2018 9:26 AM
To: Dominguez, Alexander <dominguez.alexander@epa.gov>; Lovell, Will (William) <lovell.william@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Beach, Christopher <beach.christopher@epa.gov>
Subject: LA Assn of Business and Industry

We have to have Wheeler's binder ready this evening as it turns out. Do you all have the latest talkers on Methane Rule?

Elizabeth Tate Bennett
Associate Administrator for Public Engagement & Environmental Education
Office of the Administrator
U.S. Environmental Protection Agency
(202) 564-1460
Bennett.Tate@epa.gov

Message

From: Jackson, Ryan [jackson.ryan@epa.gov]
Sent: 10/26/2018 2:19:39 PM
To: Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]
Subject: FW: PromisesMade-PromisesKept appendix.docx
Attachments: OAR Oil and Gas Actions.docx

Thanks for this. Can I talk with you through the list and ask the latest on OOOOa.

From: Dominguez, Alexander
Sent: Friday, October 26, 2018 9:55 AM
To: Jackson, Ryan <jackson.ryan@epa.gov>
Cc: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Subject: RE: PromisesMade-PromisesKept appendix.docx

Ryan, see attached OAR rules related to the oil and gas sector. Anything else please let me know.

Alex

From: Jackson, Ryan
Sent: Thursday, October 25, 2018 12:29 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: PromisesMade-PromisesKept appendix.docx

OP did an outstanding job putting this together in particular the appendix.

Alex, can you help me put together a similar list addressing simply oil and natural gas?

Rules Related to the Oil and Gas Sector

1. **Withdrawal of 2016 Information Request for the Oil and Gas Industry.** March 2017, withdrew the 2016 information collection request (ICR) relieving over 15,000 owners and operators in the oil and gas industry of this unnecessary and costly reporting burden.

2. **Targeted Improvements to NSPS for Oil and Gas (i.e. Technical Package)**: September 2018, proposed targeted improvements package to streamline implementation of Methane Rule, reduce duplicative requirements, and decrease unnecessary burdens saving the oil and gas industry up to $75 million a year, or a total of $484 million for the 2019-2025 period.

3. **Compliance Relief from NSPS for Oil and Gas (i.e. Fugitive Emission Amendments)**: March 2018, finalized amendments to Methane Rule to address unworkable requirements related to the Alaska Northern Slope and timing of repairs.

4. **Proposed Repeal of Control Technique Guidelines (CTG):** March 2018, proposed withdrawal of the 2016 Control Techniques Guidelines saving up to $49 million a year or a total of $599 million from 2021 through 2035

5. **NESHAP Reconsideration:** October 2017, granted reconsideration of several issues raised by oil and gas industry related to the 2012 Oil and Gas NESHAP (National Emission Standard for Hazardous Air Pollutants) final rule.

6. **Proposed Permit Streamlining Amendments to Indian Country FIP:** April 2018, proposed amendments to the 2016 Indian Country FIP for Uintah and Ourary Indian Reservations that limits emissions of harmful air pollutants while preserving important, streamlined permitting processes.

DRAFT

Message

From: Dominguez, Alexander [dominguez.alexander@epa.gov]
Sent: 10/25/2018 9:46:21 PM
To: Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]
Subject: For Review by SOB
Attachments: dshRLSOajd_OAR Travel Materials for AA Wheeler_Kansas_102518_v1.docx; Oil and Gas Appendix docx.docx

Message

From: Schwab, Justin [Schwab.Justin@epa.gov]
Sent: 1/24/2019 10:49:47 PM
To: Frye, Tony (Robert) [frye.robert@epa.gov]
CC: Lyons, Troy [lyons.troy@epa.gov]; Palich, Christian [palich.christian@epa.gov]; Wehrum, Bill [Wehrum.Bill@epa.gov]; Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]; Woods, Clint [woods.clint@epa.gov]; Harlow, David [harlow.david@epa.gov]; Leopold, Matt (OGC) [Leopold.Matt@epa.gov]; Fotouhi, David [Fotouhi.David@epa.gov]
Subject: QFR: revised OAR with OGC redline
Attachments: FINAL OGC EDIT FOR OAR 01242019 PM Woods Harlow Schwab EDIT for OAR 01242019 AM 2019.01.23 - PROGRAM OFFICE RESPONSES - ALL QFRs Wheeler 01.16.2019.docx

Please find attached. At least on my screen, OAR's redline is red and my redline is in blue. Also, I have a few explanatory bubbles/recommendations.

Message

From: Beeler, Cindy [Beeler.Cindy@epa.gov]
Sent: 2/23/2017 4:51:31 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]; Howard, Jodi [Howard.Jodi@epa.gov]; Shine, Brenda [Shine.Brenda@epa.gov]
Subject: FW: CCAC - O&G Methane Partnership - Technical Guidance Document on Pneumatic Controllers
Attachments: CCAC OGMP TGD 1 Pneumatic controls and pumps_Final.pdf

Hi Ladies –

You may already know about this organization (http://www.ccacoalition.org/en/content/ccac-oil-gas-methane-partnership), but wanted you to be aware of this partnership that has identified nine "core" emission sources of methane in typical oil & gas upstream operations:

1. Natural gas driven pneumatic devices, pumps
2. Centrifugal compressors with wet (oil) seals
3. Glycol dehydrators
4. Well venting of liquids unloading
5. Casinghead gas venting
6. Fugitive equipment and process leaks
7. Reciprocating compressor rod seal/packing
8. Hydrocarbon liquid storage tanks
9 .Well venting/flaring during well completion for hydraulically fractured wells

They also provide Technical Guidance Documents corresponding to each of these sources. Below is more detail on the TGD on pneumatic controllers/pumps.

Cindy Beeler
US EPA Region 8, Energy Advisor
Office of the Regional Administrator
Tel: 303-312-6204
Beeler.Cindy@epa.gov

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From: Beeler, Cindy
Sent: Thursday, February 23, 2017 9:14 AM
To: Thoma, Eben <Thoma.Eben@epa.gov>; Stovern, Michael <Stovern.Michael@epa.gov>
Subject: CCAC - O&G Methane Partnership - Technical Guidance Document on Pneumatic Controllers

Chaps –

Wanted you to be aware of the Climate and Clean Air Coalition which created a voluntary initiative to reduce methane emissions in the oil and gas sector - they launched the Oil & Gas Methane Partnership at the UN Secretary General's Climate Summit in New York in September 2014. The initiative currently has the following partner companies: BP, ENGIE E&P, Eni, Pemex, PTT, Repsol, Southwestern Energy, Total and Statoil.

They identified 9 "core" emission sources in upstream O&G of which pneumatic controllers & pumps are one. They developed Technical Guidance Documents which introduce suggested methodologies for quantifying

methane emissions from specific sources and describe established mitigation options that Partners should reference when determining if the source is "mitigated."

FYI – attached is the TGD for pneumatic devices. Partners must inventory all gas-driven controllers within their participating operations. A sample pneumatic site survey form is included in Table 1.4.

... "*As a matter of best operating practice, Partners should implement appropriate measures to identify malfunctioning devices in a timely manner. As part of these practices, it is recommended that all pneumatic controllers, including intermittent controllers should also be surveyed during Leak Detection and Repair (LDAR) or Directed Inspection and Maintenance (DI&M) programs to confirm that they are operating per design and emissions remain within specified ranges. Malfunctioning controllers should be repaired or replaced. Direct measurements and/or engineering equations could be used to determine the emission rates.*"

Cindy Beeler
US EPA Region 8, Energy Advisor
Office of the Regional Administrator
Tel: 303-312-6204
Beeler.Cindy@epa.gov

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TECHNICAL GUIDANCE DOCUMENT NUMBER 1:

NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AND PUMPS

Introduction

This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production operations. The guidance documents introduce suggested methodologies for quantifying methane emissions from specific sources and describe established mitigation options that Partners should reference when determining if the source is "mitigated."[1] The OGMP recognizes that the equipment and processes described in these documents are found in a variety of oil and gas operations, including onshore, offshore, and remote operations, and the way in which the emissions are quantified and mitigated may vary across locations and operational environments. As such, operational conditions, as well as logistical, safety and cost considerations, must be evaluated on a case-by-case basis. The OGMP assumes that methane emission mitigation actions that require shut-downs of non-redundant equipment/processes (e.g., that would result in a stoppage of operations) would be carried out during regularly scheduled maintenance activities, unless the Partner deems the corrective action to be worthy of an early/additional shut-down.

Description of Source

A major component of remote, automated control of natural gas and petroleum industry facilities is the operation of control valves, which are often powered and actuated by natural gas through pneumatic controllers. In addition, there are natural gas-powered pumps used for injecting chemicals and other purposes. Several types of this equipment release or "bleed" natural gas to the atmosphere by design. In addition to emissions by design, pneumatic controller loops and pneumatic pumps can also emit gas because they have a defect or a maintenance issue. In fact, recent field measurement studies[2] have pointed out that a large fraction of total emissions from pneumatic devices in the Production segment are a result of devices that are not operating as designed (due to a defect or maintenance issue).

Because hundreds of thousands of pneumatic controllers are used in the oil and gas industry globally, they collectively comprise a major source of methane emissions. Depending on a device's function, design, and operation, the emission rate can vary (e.g., a controller's continuous bleed, intermittent valve actuation gas vent, and a pneumatic-driven pump's actuation gas).

Controllers and pumps may be powered by compressed air or utility-supplied electricity. At remote production, gathering, and gas transmission facilities, compressed air or electricity may not be available and economical. In such cases, operators may use the available inherent energy of pressurized natural gas to power these devices.

Chemical injection pumps are common equipment in the natural gas industry where there is no reliable electricity available. These pumps inject methanol and other chemicals into wells and pipelines, and are vital to the production process. For example, methanol prevents crystalline methane hydrate formation that

[1] As described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.
[2] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, Allen et al. 2014. dx.doi.org/10.1021/es5040156 | Environ. Sci. Technol. 2015, 49, 633−640.

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can lead to blockages in pipelines. Pneumatic pumps use gas pressure to alternately push on one side and then on the other side of a diaphragm connected to a piston pump. The gas is vented at each pump movement.

Pneumatic devices consist primarily of valve controllers that regulate various process parameters such as temperature, pressure, flow rate, and liquid level. Examples include liquid level in separators, suction and discharge pressure for compressors, and temperature in heaters or gas dehydrator regenerators. There are many remote, unmanned facilities in oil and gas production (e.g., wellheads), gathering and boosting stations (e.g., gas/liquid separators, tanks, dehydrators, compressors), and transmission compressor stations to regulate. Many complex processes at these facilities require pneumatic controllers, each of which can vent an average of one cubic foot of gas per minute.[3] As a result, hundreds of thousands of pneumatic controllers exist throughout the industry and together emit significant volumes of methane.

Pneumatic controllers are designed to bleed or vent gas as part of normal operation. A steady supply of clean, dry natural gas, called supply gas or power gas - typically pressure regulated to 20-50 pounds per square inch gage (psig) - is sent to a pneumatic controller loop. The pneumatic controller loop includes a process-measuring device (liquid level, pressure, temperature) and uses the supply gas to move a control valve. Often the controller uses the supply gas as an output to the control valve diaphragm. The supply gas is routed by the controller to open or close a valve. Pneumatic gas pressure pushes against a diaphragm in the valve actuator, which pushes a connecting rod to move the valve plug open or closed. Venting this gas to the atmosphere at the controller allows a spring to push the diaphragm back, closing or opening the valve.

Pneumatic devices generally are designed in three basic configurations:

- *Continuous bleed*[4] means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. Continuous bleed devices can be either high- or low-bleed devices.
    - *Low-bleed pneumatic devices*[5] mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than 6 standard cubic feet per hour (scfh) (0.17 standard cubic meter per hour (scmh)).
    - *High-bleed pneumatic devices*[6] are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 scfh (0.17scmh).

- *Intermittent bleed pneumatic devices*[7] mean automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid

[3] U.S. EPA. *Lessons Learned: Convert Gas Pneumatic Controls To Instrument Air*. October 2006. http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf.
[4] Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, 40 CFR Part 98.6, U.S. EPA.
[5] Ibid.
[6] Ibid.
[7] Ibid.

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level, pressure, delta-pressure, and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

- *Non-gas driven*" pneumatic controllers use sources of power other than pressurized natural gas, such as compressed "instrument" air. Because these devices are not gas-driven, they do not release natural gas (or methane emissions), but they do have energy impacts because electrical power is required to drive the instrument air compressor system.

In addition, Allen et al (2014) also provided classification of pneumatic controllers based on time series:

- Intermittent-vent: Clear actuation pattern, returning to zero between actuations.
- Continuous vent: a non-zero pattern with no temporal variability.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm[8]
Natural gas-driven pneumatic controllers and pumps can be configured in a variety of ways. Partners should identify the configuration for each controller and pump. Some options include those listed in the Table 1.1 [9].

Table 1.1: Configurations for Natural Gas-Driven Pneumatic Controllers and Pumps

Configurations	Mitigated or Unmitigated
A "high-bleed" pneumatic controller continuously bleeds greater than 6 scfh (0.17 scmh) gas to the atmosphere.	Unmitigated
A pump is pneumatically powered and vents methane to the atmosphere.	
A "low-bleed" pneumatic controller continuously bleeds less than 6 scfh (0.17 scmh). (Mitigation Option A)	Mitigated
An intermittent controller only vents/emits during the de-actuation portion of a control cycle; there is no emission when the valve is in a stationery position (Mitigation Option B)	
Pneumatic controllers and pumps are powered by compressed air (Mitigation Option C)	
A pump is pneumatically powered and gas emissions are routed through a closed vent system to a control device or process. (Mitigation Option D)	

[8] Ibid.
[9] The Partners may identify additional mitigation options and the following list is not meant to be a comprehensive list of all mitigation technologies.

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Pneumatic controllers and pumps are driven by solar or electric power. (Mitigation Option E)	

Note: pneumatic controller driven by solar, electric or instrument air are not part of the "unmitigated" source category.

As a matter of best operating practice, Partners should implement appropriate measures to identify malfunctioning devices in a timely manner. As part of these practices, it is recommended that all pneumatic controllers, including intermittent controllers should also be surveyed during Leak Detection and Repair (LDAR) or Directed Inspection and Maintenance (DI&M) programs to confirm that they are operating per design and emissions remain within specified ranges[10]. Malfunctioning controllers should be repaired or replaced. Direct measurements and/or engineering equations could be used to determine the emission rates.

In addition, as equipment may be moved from one location to the other (especially with different operating pressures), it is recommended that the controller device (e.g. separator) is optimized to process the new operating conditions in the new site.

Quantification Methodology

It is recommended that one or more of the following methodologies be used to quantify volumetric methane emissions from venting of natural gas driven pneumatic controllers and pumps. In principle, direct measurement can be considered as the most accurate method for quantifying methane emissions.[11] Where a sound basis is in place, measurement can contribute to greater certainty on emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever possible to establish this basis.

The OGMP recommends partner companies use one of the following methodologies to assure the consistent quantification of emissions and the comparable evaluation of mitigation options. These quantification methodologies include: activity data count, direct measurement, manufacturer estimate, engineering estimates, or emission factor approach. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

- Activity Data Count: A key and often undervalued part of emission quantification is the activity factor, or count, of gas-driven pneumatic devices and pumps. As part of the OGMP, Partners must inventory all gas-driven controllers within their participating operations. A sample pneumatic site survey form is included in Table 1.4.

- Direct Measurement: Because pneumatic controllers do not operate with a steady gas flow rate, measurements must be taken over a long enough period to capture several cycles to determine the average flow rate of bleed (the process measurement pneumatic signal) and valve actuation gas. These measurements will provide the total gas flow rate, which is then converted to methane emissions using

[10] See TGD 2, "Fugitive Equipment and Process Leaks"

[11] Partners should conduct measurements with appropriately calibrated instruments and per the instrument manufacturer instructions. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels. Appendix A to the Technical Guidance Documents includes guidance on instrument use. Partners seeking to generate Emission Factors for their operations should use direct measurement based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons.

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the methane content of the gas. For continuous bleed devices, Partners should extrapolate the methane flow rate to account for an entire year of normal operations. For intermittent devices, the annual volume of methane emitted is calculated by multiplying the measured average methane emission flow rate per actuation by the estimated number of actuations of the pneumatic device or pump. Other quantification methodologies are provided for cases where direct measurement is not feasible. Partners are encouraged to quantify annual volumetric methane emissions from pneumatic devices and pumps using one of the following methodologies:

Direct measurement[12] should start with an engineering analysis (field observation) of the pneumatic control loop to determine how the control loop operates and where the bleed emissions occur from a particular pneumatic controller or pump. This is important so that the measurement points are accurately identified and that measurements completely capture a device's methane emissions. A chemical injection pump typically vents methane locally and has no other equipment associated with its emissions. Partners, however, should always perform a full survey of their facilities before assuming zero emissions elsewhere.

Methods from Allen et al. (2013[13]) and Allen et al. (2014) should be employed and should cover at least 15 minutes of sampling. This will not be possible in all cases, as some intermittent devices may not actuate during an entire day. To account for non-zero actuations, recommended measurement tools for pneumatic devices include the following[14]:

- Direct gas measurement by upstream flow meter in the supply gas line
- High volume sampler
- Calibrated vent bag

Partners should measure the actuator gas from a pneumatic chemical injection pump vent over a period of time that includes several cycles of pumping strokes. Recommended measurement tools for chemical injection pumps include the following:

- Direct gas measurement by upstream flow meter in the supply gas line
- High volume sampler (ideally altered to capture 1-2 second data)
- Calibrated vent bag

If Partners have a large number of pneumatic controllers and pumps of similar type and manufacturer at their facilities, they might find measuring bleed rates for each device burdensome. The operator may consider measurement of a representative sample of the total population in lieu of measurement at every device, taking into account controller service and design used by the Partner across its facilities.

For more details regarding each measurement tool, including applicability and measurement methods, please refer to Appendix A.

- Manufacturer Estimate: Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when the data can be acquired. Appendix A in the Natural Gas STAR technical document "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural

[12] U.S. EPA. Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems, Section 98.234 Monitoring and QA/QC requirements, 40 CFR 98.234(c) and 98.234(d). http://www.ecfr.gov/cgi-bin/text-idx?SID=0be28a76d43cbee6ce31f26e5a2bc9c0&node=40:22.0.1.1.3.23&rgn=div6.
[13] Measurements of methane emissions at natural gas production sites in the United States, www.pnas.org/cgi/doi/10.1073/pnas.1304880110. October 29, 2013.
[14] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers, Allen et al. 2014 dx.doi.org/10.1021/es5040156 | Environ. Sci. Technol. 2015, 49, 633−640.

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Gas Industry" lists the brand, model, and gas bleed rate information for various pneumatic controllers as provided by manufacturers. This list is not exhaustive, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included. Also, Partners can consult product lists on manufacturer websites for any recent updates and additional details on particular pneumatic device(s). For chemical injection pumps, emissions data might be available online or by contacting the manufacturer(s) directly. The OGMP has developed a list of commonly used controller devices listed by various manufacturers in Table 1.5. Partners may use this list to classify the controllers in the Survey Form and also employ the manufacturer's stated emission rate or the rates included in Table 1.5. Partners should verify the manufacturer provided bleed rate for the continuous bleed device as it pertains to local site conditions (e.g. gas composition, supply pressure etc). For example, "data provided by the manufacturer" is subject to interpretation as sometimes the manufacturer is providing bleed data in order to make sure a supply gas system is not undersized, rather than to make sure emissions are accurate. Manufacturer assumed gas consumption data is only useful if the data refers to a continuous bleed rate, since the manufacturer cannot estimate gas use for an intermittent device that only bleeds when actuated. Finally, manufacturer data is only if accurate for the exact application (the specific supply gas pressure, for example).

- Engineering Estimates: For intermittent vent controllers in on/off service, every time the device shifts from "on" to "off", the same volume of gas is vented. This volume per actuation (Volscf) can be calculated by Equation 1[15]:

$$Vol_{\text{scf}} = \left[\frac{\pi}{4} ID^2 \times \text{L}_{\text{pipe}} + \Delta\text{Vol}_{\text{bonnet}}\right] \times \left[\frac{P_{\text{control}} + P_{\text{atm}}}{P_{\text{std}}}\right]$$

Annual Emissions = (Estimated number of actuations per device per year) X (Vol_{scf})

Variable	Description	FPS Units	SI Units
ID_{pipe}	Inside diameter of piping	scf	scm
L_{pipe}	Length of all piping in system	ft	m
$\Delta\text{Vol}_{\text{bonnet}}$	The change in the physical volume of a pneumatic valve actuator when changed from at rest to fully actuated	scf	scm
P_{atm}	Local atmospheric pressure	psia	kPaa
P_{control}	Pressure of the supply gas system	psig	kPag
P_{std}	Pressure designated by proper authority to represent the standard pressure to be used for aggregating volumes	psia	kPaa

This approach requires a count of actuations for each device per year in order to calculate annual emissions. Therefore, an estimated number of actuations per year must be developed employing onsite knowledge.

[15] Simpson, D.A. "Pneumatic Controllers in Upstream Oil and Gas." Oil and Gas Facilities, Society of Petroleum Engineers. October 2014. pp. 83-96.

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- Emission Factors: If they do not select the direct measurement or the manufacturers' data approach is not selected, an emission factor approach may be used. Partners are encouraged to use emission factors that best represent conditions and practices at their facilities. Default methane emission factors are provided in Table 1.2, Table 1.3, and Table 1.4 at the end of this section.

  The default emission factors represented in Table 1.2 and 1.3 are based on data derived from the 1996 GRI/EPA report[16] and generally represent estimates of average emissions and populations of devices during the survey period in the early 1990s, but may be inaccurate representations of any individual device, particularly for intermittent devices or even current production operations (e.g., hydraulically fractured oil and gas wells). Partners should determine which emission factors best represent conditions and practices at their facilities and internal corporate protocols.

Mitigation Option A – Retrofit pneumatic high-bleed gas controllers with low-/no-bleed controllers to reduce gas emitted.

Partners can achieve significant methane emission reductions and save money by replacing or retrofitting high-bleed pneumatic controllers if the process can handle a reduction in end-device (combination of the actuator and process valve controlling the process) responsiveness and slower operation of the controller. Low-bleed gas-driven controllers can replace high-bleed gas-driven controllers in many, but not all, applications.[17] Partners should consult pneumatic controller vendors or other instrumentation specialists for details such as costs, applicability, and specifications of various controllers. Partners should specify pneumatic controllers with bleed rates at or less than 6 scfh. Not all manufacturers report their controllers' bleed rates similarly; therefore, Partners should ensure a controller is indeed low-bleed at their service's pneumatic gas supply pressure before purchasing.

Before purchasing low-bleed equipment, Partners also should first identify all the candidates for replacement or retrofit. This process can occur during a specific facility-wide pneumatics survey or during normal maintenance. Partners should use the sample survey template or develop a comparable survey and include the make/model, function, location, condition, and bleed rate (also recording either continuous or intermittent bleed).

Operational Considerations

Applicability can depend on the function of an individual controller (i.e., whether the controller monitors level, pressure, temperature, or flow rate). As stated in the previous section, some high-bleed pneumatic controllers might not be suitable for low-bleed replacement because a process condition might require a fast or precise control response so that it does not drift too far from the desired set point. A slower acting controller could damage equipment, become a safety issue, or both. An example is a compressor where pneumatic controllers monitor the suction and discharge pressure and actuate a recycle by-pass when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate might fluctuate widely or unpredictably. This situation requires a responsive high-bleed controller to ensure that the gas flow can be mitigated in all situations.

[16] Methane Emissions From the Natural Gas Industry. June1996. Volume 12: Pneumatic Devices.
[17] Oil and Natural Gas Sector Pneumatic Devices Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel April 2014. Prepared by U.S. EPA Office of Air Quality Planning and Standards (OAQPS). http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

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Temperature and level controllers are typically present in control situations that are not prone to wide fluctuation or the equipment can readily and safely accommodate the fluctuation. Therefore, such processes can accommodate control from a low-bleed device, which is slower acting.

Safety concerns could be an issue, but only in specific situations because emergency isolation of pressure relief valves are not bleeding controllers. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an emergency shutdown (ESD) or pressure relief valve (PRV) actuation occurs, the equipment in place for such an event is spring loaded. During a safety issue or emergency, the pneumatic gas supply could be lost. For this reason, control valves are deliberately selected to either open or close on loss of pneumatic gas supply.

The implementation of this technology will occur during shutdown of the equipment or system related to the pneumatic device(s) and requires the installation of:

- Low-bleed/no-bleed pneumatic controller
- Any additional piping, fittings, etc. (if needed)

Methane Emission Reduction Estimate

Partners can expect to achieve a significant reduction in methane emissions from high-bleed pneumatic devices after implementing this technology. Once converted to low-bleed, a pneumatic device should emit no more than 0.17 scmh or 6 scfh. Recent U.S. regulations require new continuous high-bleed pneumatic controllers in oil and gas production to be low-bleed (i.e., bleed rate is 6 scfh (0.17 scmh or less).[18]

Methane Emissions Reductions = Baseline "Unmitigated" Emission Rate (scfh or scmh) – "Mitigated" Emission Rate (scfh or scmh)

Baseline "unmitigated" emission rate for high-bleed controllers are calculated using one of the following methods:

- Direct measurement averaged on a scfh basis per device or scm basis per device.
- Manufacturer's estimate.
- If using default values, the unmitigated emission rates from high-bleed controllers equals 37.3 scfh or 1.1 scmh.

Mitigated emission rate for low-bleed controllers:

- Direct measurement averaged on a standard cubic feet per hour (scfh) per device or standard cubic meter (scm) per device.
- Manufacturer's estimate

[18] U.S. EPA. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews: Final Rule (40 CFR Part 60, Subpart OOOO). August 16, 2012. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

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- If using default values, uncontrolled emission rates from low bleed controllers equals 1.39 scfh or 0.04 scmh

For more information, see Natural Gas STAR technical documents "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry" (http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf).

Economic Considerations

The costs for installing a low-bleed pneumatic controller include capital and annual operation and maintenance (O&M) costs. The capital costs for a low-bleed controller can range from approximately $400 to $3,500, depending on the controller's function and design.[19] Annual O&M costs are typically negligible, and the avoided maintenance costs for an older controller are typically included as a benefit in the economic analysis.

Partners should determine the volume of gas that will be saved when replacing a high-bleed controller with a low-bleed one. Direct measurement of bleed emissions from both the high- and low-bleed controllers is the most accurate method. If direct measurement is not possible, operators should use the bleed rates specified by manufacturers on product data sheets. The annual gas savings are equal to the difference in the annual bleed rates between the replaced high-bleed controller and the new low-bleed device (assuming 8,760 hours of operation) multiplied by the gas price.

Once Partners have determined which pneumatic controllers can be cost-effectively replaced or retrofitted, they should develop a strategy for implementing this project. Depending on their schedules and procedures, replacement and retrofits can be prioritized, or replacing all eligible high-bleed devices (those that meet the criteria in a company's analysis) at one time might be more economical. A full replacement can help minimize labor/installation costs and shutdown time.

Mitigation Option B – Ensure intermittent controller only vents/emits during the de-actuation portion of a control cycle with no emission when the valve is in a stationery position

Intermittent controllers typically have low emissions but may exceed 52,560 scfy (1,489 scmy) if they actuate frequently (e.g., liquid level controllers associated with high production wells). Additionally, Allen et al. 2014 found that intermittent controllers with malfunctions[20] can have high emissions due to venting between actuations. The emissions from malfunctioning intermittent controllers had almost 40 times higher emissions than properly functioning controllers (35.9 vs. 0.9 scfh).

Mitigation Option C – Install instrument air system or electric actuators for pneumatic gas supply/use.

Partners can achieve significant methane emission reductions when converting a pneumatic control system from natural gas to compressed instrument air. By substituting air, companies are effectively eliminating methane emissions entirely and creating additional safety benefits (because of the elimination of a flammable substance). Partners should first fully evaluate their facilities to identify viable candidates for

[19] EPA. Lessons Learned: *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Appendix B. October 2006. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.
[20] Intermittent* time-series classification (clear actuation pattern) with non-zero baseline.

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this mitigation option, however, because it is not as universal as other options. Instrument air systems require an accessible and reliable source of electricity to be economical and beneficial to partner companies. Typically, processing plants and facilities have the most consistently available use of electricity; however, Partners might have production, transmission, and distribution facilities with electricity as well.

An instrument air system consists of a compressor(s), dehydrator, volume tank, and power source. The principal costs for converting a gas-powered pneumatic system to instrument air are the initial capital costs (for compressors, dehydrator, volume tank, etc.) and the O&M costs to power the compressor motor. Existing gas-powered pneumatic components (e.g., piping, controllers, and actuators) also are compatible with instrument air, so Partners will save on capital costs for this equipment.

Operational Considerations

The two main requirements for an instrument air system are 1) reliable electric power and 2) a large enough number of pneumatic devices to justify the cost. Once a project site has been identified, it is important to determine the necessary capacity of the instrument air system. The capacity needed is a direct function of the amount of compressed air needed to 1) meet utility air requirements and 2) operate the pneumatic instrumentation.

Utility air does not have to be dried. The frequency and volumes of such utility air uses are additive. Partners will need to evaluate these other compressed air services on a site-specific basis, allowing for the possibility of expansion at the site. A general rule of thumb is to assume that the maximum rate of compressed air needed periodically for utility purposes will be double the steady rate used for instrument air[21] (e.g., pneumatic air uses: one-third for instrument air, two-thirds for utility air).

The compressed air needs for the pneumatic system are equivalent to the volume of gas being used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by a direct meter reading (if a meter has been installed). In non-metered systems, a conservative rule of thumb for sizing air systems is one cubic foot per minute (cfm) of instrument air for each control loop (consisting of a pneumatic controller and a control valve).[22]

The initial estimate for the instrument air volume needed needs to be adjusted to account for air losses during the drying process. Typically, the membrane filters in the air dryer consume about 17 percent of the air input.[23] As a result, the estimated volume of instrument air usage is 83 percent of the total compressed air supply (i.e., divide estimated air usage by 83 percent). Desiccant dryers do not consume air and therefore require no adjustment.

The implementation of this technology will occur during shutdown of the equipment or system related to the pneumatic device(s) and requires the installation of:

- Instrument air compressor
- Power source for compressor
- Dehydrator or air dryer
- Weatherproof enclosure and piping
- Volume tank

Methane Emission Reduction Estimate

[21] U.S. EPA. *Lessons Learned: Convert Gas Pneumatic Controls To Instrument Air*. October 2006. http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf.
[22] Ibid.
[23] Ibid.

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Companies can expect to reduce methane emissions from pneumatic device and pump venting by approximately 100 percent after implementing this technology.

For more information, see Natural Gas STAR technical Document "Converting Gas Pneumatic Controls to Instrument Air" (http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf).

Economic Considerations

The typical costs associated with installing and operating an instrument air system include the installation costs for compressors, dryers, and volume tanks, and energy costs. The actual installation costs are a function of the size, location, and other location-specific factors. A typical conversion of a natural gas pneumatic control system to compressed instrument air costs approximately $45,000 to $75,000.[24]

To estimate the cost for an instrument air system, all expenses associated with the compressor, dryer, volume tank, and power supply need to be calculated. Most vendors will typically provide equipment cost estimates and installation requirements (e.g., compressor size, motor horsepower, electrical power requirements, and storage capacity).

For the instrument air compressor, it is common to install two compressors at a facility (one operating and one on stand-by) to ensure reliability and allow for maintenance and overhauls without service interruptions. The capacity of each compressor must be sufficient to handle the total expected compressed air volume for the project (i.e., both instrument and utility air). For screw-type compressors, Partners should expect to overhaul the unit every five to six years.[25] This normally involves exchanging the compressor core for a rebuilt compressor at a cost of approximately $4,000, with an additional $700 in labor expenses and a $650 salvage value.[26]

For volume tanks, the rule of thumb in determining the size of the tank is 1-gallon capacity for each cubic foot of compressed air. Volume tanks have essentially no O&M costs. A typical equipment cost range is $650 to $4,000, depending on the tank capacity.[27]

For air dryers, the most common dryer used in small to medium applications is a permeable membrane dryer. Larger air systems can use multiple membrane dryers or alumina bed desiccant dryers (more cost-effective). Membrane dryers filter out oil mist and particulate solids and have no moving parts. As a result, annual operating costs are kept low. The appropriate sized dryer would need to accommodate the expected volume of gas needed for the instrument air system. Typical air dryer equipment costs are $2,000 to $13,100 and annual service costs are $700 to $4,300.[28]

It is also necessary to estimate the energy costs associated with operating the instrument air system. The highest operating cost is electricity for the air compressor (unless there is another on-site energy source). Electricity costs average around $13,100 annually.[29] This assumes that electricity is $0.75 per kilowatt-hour, the main compressor runs at full capacity half the time (i.e., 50 percent operating factor), and the backup compressor is on standby.

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[24] U.S. EPA. *Lessons Learned: Convert Gas Pneumatic Controls To Instrument Air*. October 2006. http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf.
[25] Ibid.
[26] Ibid.
[27] Ibid.
[28] Ibid.
[29] Ibid.

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Due to the economic considerations, this option may only be viable for multi-well pads, large compressor stations, or large gas handling facilities.

Mitigation Option D – Routing natural gas-driven pump emissions to an existing combustion device or vapor recovery unit.

The methane emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps can be reduced by 95 percent if a control device is already available on site.

This mitigation option can reduce emissions from piston and diaphragm natural gas-driven pumps, which involves routing the gas to a process or routing the gas to a combustor (often done as part of the storage vessel control system). Based on a 95 percent reduction, OGMP estimates the reduction in emissions in the production segment to be 0.36 tons per year (tpy) methane and 0.10 tpy volatile organic compounds (VOC) per piston pump and 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump.

Mitigation Option E – Replace pneumatic pumps with electric pumps, including solar electric pumps for smaller applications such as chemical and methanol injection.

Pneumatic controllers and chemical injection pumps typically operate on pressurized natural gas because they are located at remote field sites that do not have reliable electrical power. Partners also have achieved cost-efficient methane emission reductions by replacing pneumatic controllers and chemical injection pumps with alternative pumps including solar-charged DC electric devices, standard AC electric devices, and instrument air. In particular, the use of instrument air for pneumatic controllers and chemical injection pumps increases operational efficiency, decreases maintenance costs, and reduces emissions of methane, hazardous air pollutants (HAPs), and VOCs.

Operational Considerations

Low-volume pneumatic controllers and chemical injection pumps at remote sites are candidates for electric pumps if the site has an electricity source or if sunlight is available for solar-charged DC pumps. Other operating considerations are the installation of solar panels and a storage battery for each solar device. Besides reviewing the operating manual, minimal additional training is involved to operate solar electric devices.

This mitigation project is applicable to all industry sectors where pneumatic pumps are available for conversion. In gas production, typical applications include methanol injection in wells and pipelines and corrosion inhibitor injection for wells and other applicable equipment. Chemical injection pumps in production are usually sized to inject 6 to 8 gallons of methanol a day.[30]

Solar-powered pneumatic devices and chemical injection pumps can accommodate various ranges of injection pressures and throughputs. Small-volume solar pumps can handle about 5 gallons per day at 1,000 psig discharge.[31] Large-volume solar pumps typically can inject approximately 38 to 100 gallons per day at 1,200 to 3,000 psig discharge.[32] For maintenance considerations, solar panels and storage batteries help lower downtime and service costs because they typically require very minimal maintenance. Solar panels can last up to 15 years, and electric motors in continuous use have a lifespan of approximately five years.

[30] U.S. EPA. PRO #202: *Convert Natural Gas-Driven Chemical Pumps*. 2011. http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf.
[31] Ibid.
[32] Ibid.

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Pneumatic controllers and chemical injection pumps also can be powered by instrument air instead of natural gas. Partners should have an existing instrument air system with excess capacity, however, because installing a new instrument air system for only a few pneumatic controllers or pumps is less cost-effective.

The implementation of pneumatic devices powered by solar/electric power or instrument air will occur during well or pipeline downtime and requires the installation of the following equipment:

- Solar/electric power
  - Electric control valve with actuator and controller or electric pump
  - Solar panels
  - Storage battery(ies)
- Instrument air
  - Electric control valve with actuator and controller or electric pump
  - Air compressor, driver and accumulator
  - Air dryer
  - Weatherproof enclosure
  - Electric service or an internal combustion engine to power the compressed air system
  - Piping and regulators
  - Control system

Methane Emission Reduction Estimate

Companies can expect to achieve a 100 percent reduction in methane emissions associated with pneumatic controller and pump venting after replacing a gas-assisted system with solar power, electricity, or an instrument air system.

For more information, see the Natural Gas STAR technical document "Convert Natural Gas-Driven Chemical Pumps" (http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf).

Economic Considerations

As replacements for pneumatic pumps (e.g., chemical injection), solar-charged electric pumps cost about $2,000 per pump.[33] A replacement control valve with actuator and controller cost about $4,000 per controller.[34] The installation cost is approximately $2,000 and no training costs for operating electric pumps are necessary. Data on the annual O&M costs for solar pumps are minimal, but costs are estimated to be lower than pneumatic pump annual O&M costs at $100 to $1,000.[16] Gas savings are typically 200 Mcf per pump, and at $3 per Mcf, the value saved is $600 annually.[16] The payback for this project will fluctuate with the gas price, and at $3 per Mcf, the payback is three to four years per pump replacement.[16] The payout for a high, continuous bleed controller is under six years. However, this option may not be economical for low, continuous bleed controllers or intermittent bleed controllers.

For companies interested in replacing gas-driven pneumatic controllers and pumps with instrument air, the major capital cost is from installing the piping to connect an existing air compressor to the pneumatic pump(s). If a Partner does not already have an existing instrument air system on site, however, the capital costs will significantly increase. The annual O&M costs are primarily from the cost of electricity to compress the air. Payback for this project is typically quick, ranging from one month to slightly less than two years where an existing instrument air system is on site.[16] Where instrument air is not currently

[33] EPA. PRO #202: *Convert Natural Gas-Driven Chemical Pumps*. 2011. http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf.
[34] Based on a 2-inch Fisher easy-Drive D4 actuator and Fisher L2e controller,

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available, this option may only be economically viable for multi-well pads, large compressor stations, or large gas handling facilities.

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APPENDIX

Emission Factors

Emissions factors for pneumatic devices are taken from American Petroleum Institute (API) and Gas Research Institute (GRI) reports and are summarized in Table 1.2 below. These emission factors are also used under subpart W of EPA's Greenhouse Gas Reporting Program. Partners are encouraged to use emission factors that best represent conditions and practices at their facilities. As shown in Table 1.2, publicly available studies have shown that there is some variability observed in emissions factors.

Table 1.2: Default Emission Factors for Pneumatic Controller Vents

Sector/Source	Methane Emission Factor (scm/hour/device)	Methane Emission Factor (scf/hour/device)
Oil & Gas Production		
High continuous bleed pneumatic controller vents ("Unmitigated")[A]	1.1	37.3
Intermittent bleed pneumatic controller vents [A]	0.4	13.5
Low continuous bleed pneumatic controller vents ("Mitigated")[A]	0.04	1.39
Gas Transmission & Storage		
High continuous bleed pneumatic controller vents ("Unmitigated")[B]	0.5	18.20
Intermittent bleed pneumatic controller vents [B]	0.07	2.35
Low continuous bleed pneumatic controller vents ("Mitigated")[A]	0.04	1.37

[1]Greenhouse Gas Reporting Program, 40 CFR Part 98, Subpart W, Table W-1A. http://www.ecfr.gov/cgi-bin/text-idx?SID=7c6f763ebd2964325e5d2ec457ac2377&mc=true&node=ap40.21.98_1238.1&rgn=div9.

[B] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 12. Page 52. June 1996. http://epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf.

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Table 1.3: Default Emission Factors for Pneumatic Pumps

Sector/Source	Methane Emission Factor (scm/hour/pump)	Methane Emission Factor (scf/hour/pump)
Oil & Gas Production		
Pneumatic pumps - Diaphragm("Unmitigated")[A]	0.53	18.58
Pneumatic pumps – Piston ("Unmitigated")[A]	0.06	2.03
Solar, electric, or instrument air pump ("Mitigated")	0.0	0.0

[A] Table 7-2, Control Technique Guidelines, USEPA (August 18, 2015), Data Source: 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.

Table 1.4: Pneumatic Controller Survey Form

Company Device Identifier	Classification based on time series (intermittent (I) OR continuous (C)	Manufacturer/ Model	Manufacturer Classification (High (H), Low (L))	Controller application (Level, Temperature, Pressure, Position, Safety)	Tubing Diameter (in or m)	Tubing Length Between Device and Control Valve (in or m)	Supply Pressure(psig or kPag)	Actuation frequency (average number of actuations per hour)

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Table 1.5: High-Bleed Pneumatic Devices [35]

Pneumatic Device	Average Bleed Rate (scm/hr)	Type
Norriseal 1001	0.19	Level Controller
Fisher i2P-100	0.22	Transducer
Generic High-Bleed Intermittent Controller	0.25	
Generic High-Bleed Controller	0.26	
Fisher Fieldvue DVC6000	0.26	Positioner
Fisher 546	0.35	Transducer
Williams P125	0.41	Pump
Fisher 4150	0.42	Pressure Controller
Generic Piston Pump	0.59	Pump
Williams P500	0.70	Pump
Williams P250	0.80	Pump
Texsteam 5100	0.97	Pump
Generic Diaphragm Pump	1.05	Pump
Morgan HD312	1.13	Pump
Invalco Snap-Acting	7.76	
Invalco CTU	8.07	
Invalco CTU	9.17	
Invalco CTU-415	11.75	
Invalco Throttling	14.66	
Invalco CTU	15.28	
Invalco CTU-415	16.91	
Invalco CTU-415	16.96	
Invalco CTU-415	18.00	
Invalco CTS-215	18.54	
Invalco CTU	18.59	
Invalco CTU	19.89	
Invalco CTU	20.15	
Invalco CTU-215	21.06	
Invalco CTU	27.85	
Invalco CTU	29.26	
Invalco CTU-215	29.78	

[35] Prasino Group (2013). http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf.
Blue Source Canada (2011). http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/offset-project-development-opportunities/high-bleed_to_low-bleed_module.pdf.

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Message

From: Blackman, Jerome [Blackman.Jerome@epa.gov]
Sent: 3/12/2019 8:31:51 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
CC: Waltzer, Suzanne [Waltzer.Suzanne@epa.gov]
Subject: FW: Save The Date: March 6th - NG Compressor Station Stakeholder Meeting
Attachments: MDE Stakeholder Presentation 03062019.pdf

Hi Amy,

Suzie Waltzer suggested that I share this Maryland Department of the Environment presentation with you.
The State is addressing methane emissions from various sources including emissions from compressor stations!

Cheers!

Jerome

From: Blackman, Jerome
Sent: Tuesday, March 05, 2019 11:43 AM
To: Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Elger, Nicholas <Elger.Nicholas@epa.gov>; Frankiewicz, Thomas <Frankiewicz.Thomas@epa.gov>; Menassian, Sarah <menassian.sarah@epa.gov>; Cappel, Kirsten <Cappel.Kirsten@epa.gov>
Cc: Franklin, Pamela <Franklin.Pamela@epa.gov>
Subject: FW: Save The Date: March 6th - NG Compressor Station Stakeholder Meeting

Advance copy of MDE's Compressor Station Stakeholder Meeting for tomorrow.
In addition to compressor stations, MDE will also be addressing methane emissions from landfills and waste water treatment plants.

Jerome

From: Joshua Shodeinde -MDE- <joshua.shodeinde@maryland.gov>
Sent: Tuesday, March 05, 2019 11:24 AM
Subject: Re: Save The Date: March 6th - NG Compressor Station Stakeholder Meeting

Good Morning All,

Please find attached presentation for tomorrow's stakeholder meeting.

Sincerely,

Joshua Shodeinde

On Fri, Mar 1, 2019 at 12:55 PM Joshua Shodeinde -MDE- <joshua.shodeinde@maryland.gov> wrote:

> Good Afternoon All,
>
> A reminder of MDE's upcoming stakeholder meeting to discuss addressing methane emissions from the oil and natural gas industry scheduled for **Wednesday, March 6, 2019** at **10 AM** at the Maryland Department of the Environment (MDE Lobby, Aqua and Terra Conference Room, 1800 Washington Boulevard, Baltimore, MD 21230.

Please find attached agenda along with webinar information (included below for your inconvenience):

https://global.gotomeeting.com/join/566058309
United States
Access Code: Ex. 6 Personal Privacy (PP)

We look forward to your participation.

Sincerely,

Joshua Shodeinde

---------- Forwarded message ---------
From: **Joshua Shodeinde -MDE-** <joshua.shodeinde@maryland.gov>
Date: Fri, Feb 1, 2019 at 11:52 AM
Subject: Save The Date: March 6th - NG Compressor Station Stakeholder Meeting

Dear stakeholders,

Please save **March 6, 2019**, at **10:00 AM** for a meeting at the Maryland Department of the Environment (MDE Lobby, Aqua and Terra Conference Room, 1800 Washington Boulevard, Baltimore, MD 21230). MDE would like to meet with stakeholders to discuss addressing methane emissions from natural gas (NG) compressor stations.

Meeting materials will be distributed prior to the meeting and a conference line will be made available for your convenience. Please contact me at 410-537-3866 or via e-mail at joshua.shodeinde@maryland.gov should you have any questions.

Sincerely,

Joshua Shodeinde

--
Joshua Shodeinde
Regulatory and Compliance Engineer

Maryland Department of the Environment
Air and Radiation Administration
Air Quality Planning Program
1800 Washington Blvd, STE 730
Baltimore, MD 21230
410.537-3866
joshua.shodeinde@maryland.gov

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Joshua Shodeinde
Regulatory and Compliance Engineer

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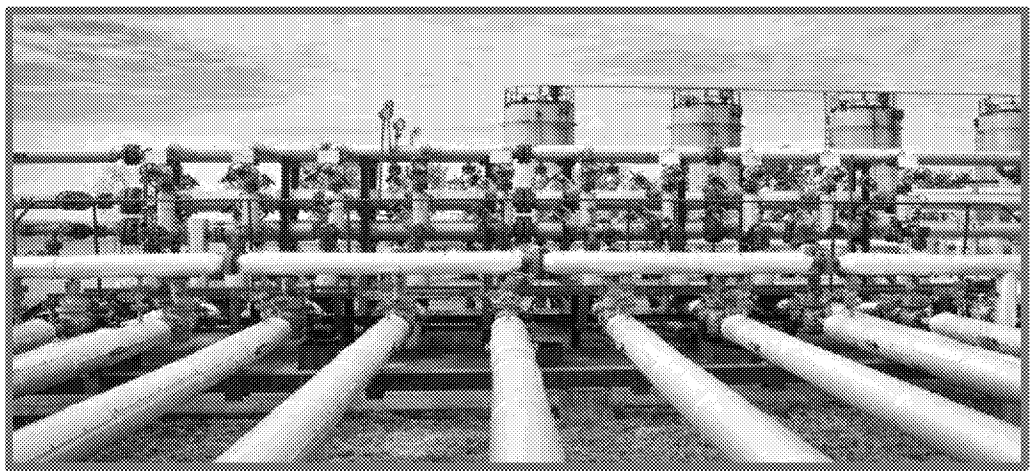
Click here to complete a three question customer experience survey.

Maryland
Department of
the Environment

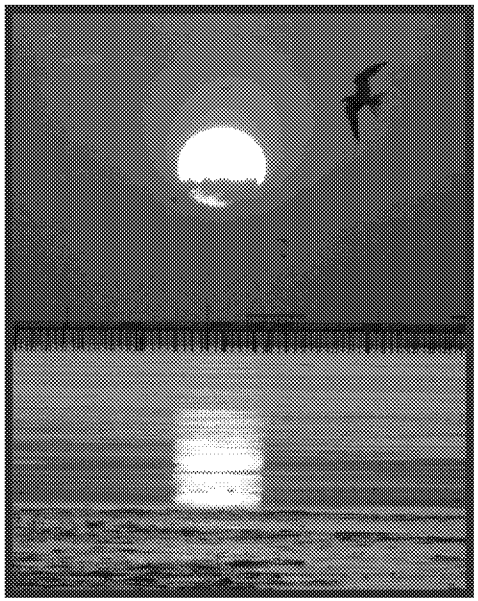
Minimizing Methane Emissions from Natural Gas Compressor Stations and other Related Equipment



Tad Aburn and Joshua Shodeinde, MDE - Stakeholder Meeting # 3 - March 6, 2019

Presentation Outline

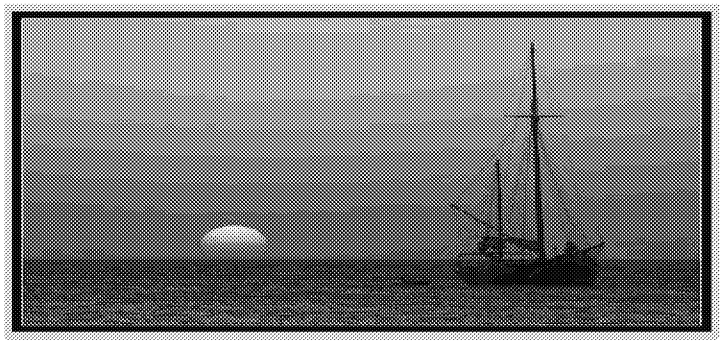
- Background
  - Why are we pushing this issue
- Methane Emission Minimization Plans
  - Overview - Phasing
  - Regulatory Requirements
  - Non-regulatory, Data-Driven Requirements
- Discussion/Comments
- Next Steps



Maryland
Department of
the Environment

Why is MDE Pushing this Issue

- Maryland has one of the country's most aggressive programs to address climate change
- Methane is a highly potent greenhouse gas that needs to be acted upon quickly because it is a short-lived climate pollutant (SLCP)
- Leaking methane has been identified by researchers and regulators as a major issue that needs to be addressed
- Maryland has 3 initiatives started to address leaking methane
  - Compressor stations and other related equipment (today's meeting)
  - Landfills
  - Wastewater Treatment Plants



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The Greenhouse Gas Emission Reduction Acts (GGRA) of 2009 and 2016

- Originated in 2007 by Executive Order which resulted in a 2008 "Climate Action Plan"
- This led to the "Greenhouse Gas Emission Reduction Act" of 2009
  - 25 % Greenhouse Gas (GHG) Emission reduction by 2020
- 2009 law reauthorized in 2016 … new goals added
  - 40 % GHG reduction by 2030
- The acts also require that the States GHG reduction plans to support a healthy economy and create new jobs

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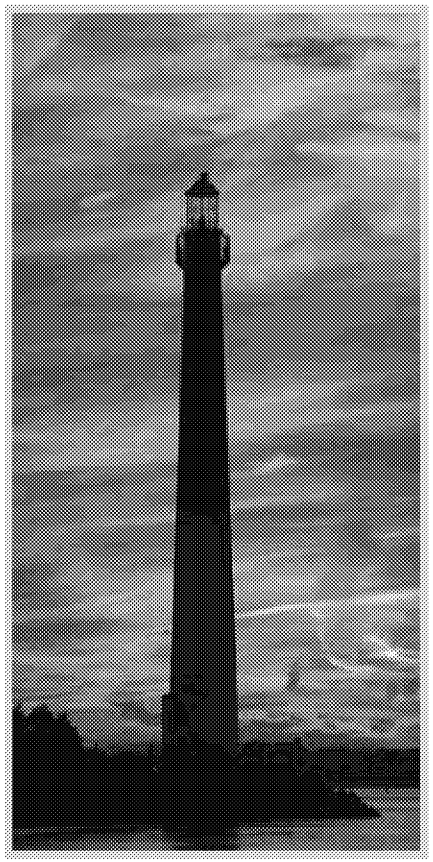
The Maryland Commission on Climate Change (MCCC)

- MCCC codified into law in 2015
- Establishes a balanced, bipartisan Commission
  - Representatives from state and local government, the private sector, environmental advocacy groups, labor, the general public and more
- Basic charge of the Commission:
  - Provide recommendations on how to reduce GHG emissions and adapt to the impacts of climate change
- Full Commission and four working groups (Mitigation, Adaptation, Science and Communications) meet routinely
  - All meetings open to public
- MCCC has recommended that reducing in-state methane leakage be a very high priority



https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Pages/index.aspx

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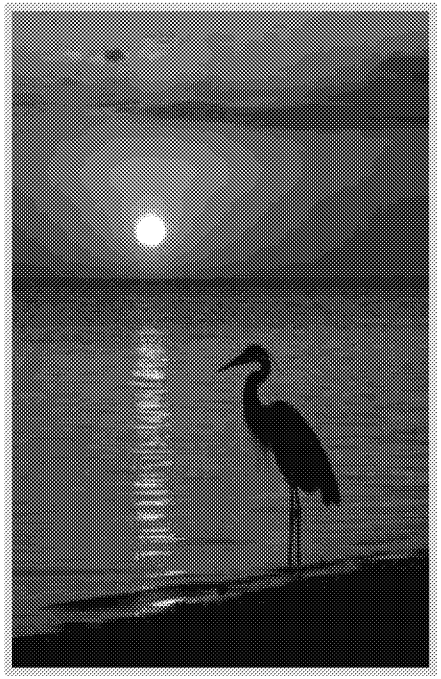
The U.S. Climate Alliance

- Maryland joined the U.S. Climate Alliance (USCA) on January 10, 2018
  - Originally, an alliance of 12 states … now 22 states
- Basic mission … to meet the goals of the Paris Climate Agreement … at least 26-28 percent below 2005 levels by 2025
- Multiple working groups … one focused on SLCP
  - Pushing efforts to reduce methane, hydroflourocarbons (HFCs) and black carbon
- Besides our work on methane, Maryland is joining other states like CA, and NY to adopt 2019 regulations to phase out the use of HFCs



www.usclimatealliance.org/

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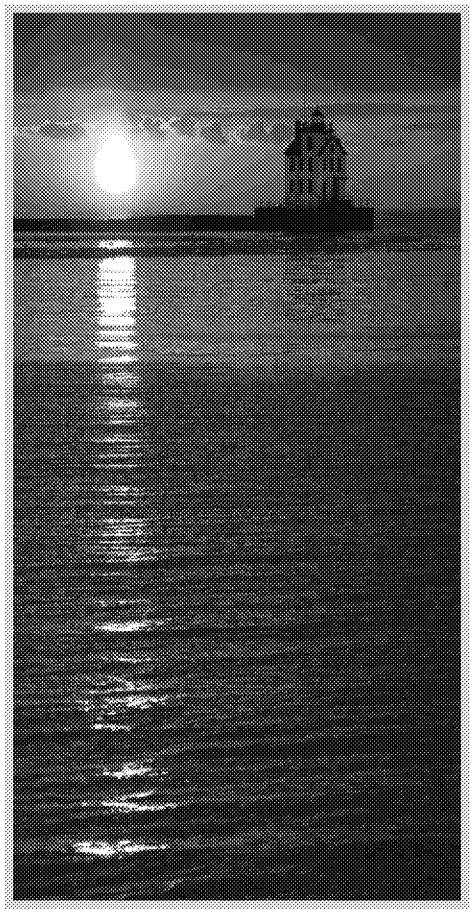
Climate Alliance States

Recent Activity



- California law requires reducing emissions of methane and HFCs by 40 percent, below 2013 levels by 2030
- Massachusetts is the first state in the country to impose annually declining methane emissions limits (for 2018, 2019, and 2020) on natural gas distribution system operators
- Colorado was the first state to regulate methane emissions from oil and gas operations. The 2014 rules will prevent an estimated 65,000 tons per year of methane
- New York has developed a Methane Reduction Plan, including 25 measures across 5 agencies, to cut methane from oil and gas infrastructure, waste management, and agriculture

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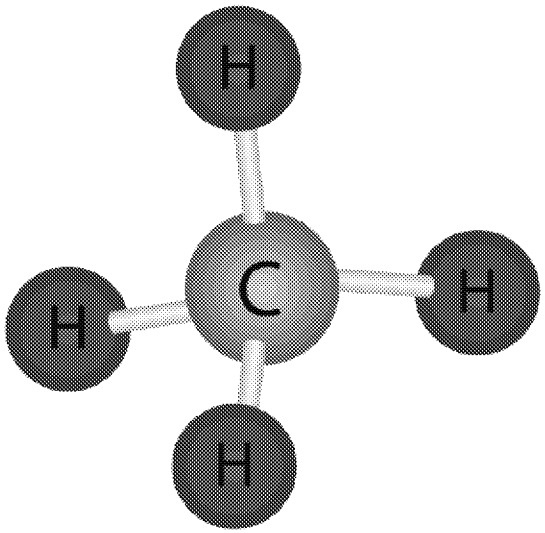
Methane and Climate Change … the Basics

- The second most prevalent greenhouse gas emitted in the U.S.
  - About 10% of all U.S. greenhouse gas emissions
- The atmospheric lifetime of methane is much shorter than carbon dioxide (CO_2)
- On a per unit basis, methane is at least 25 times more potent at trapping heat in the atmosphere than CO_2 over a 100 year period, and about 72 times more potent over a 20 year period



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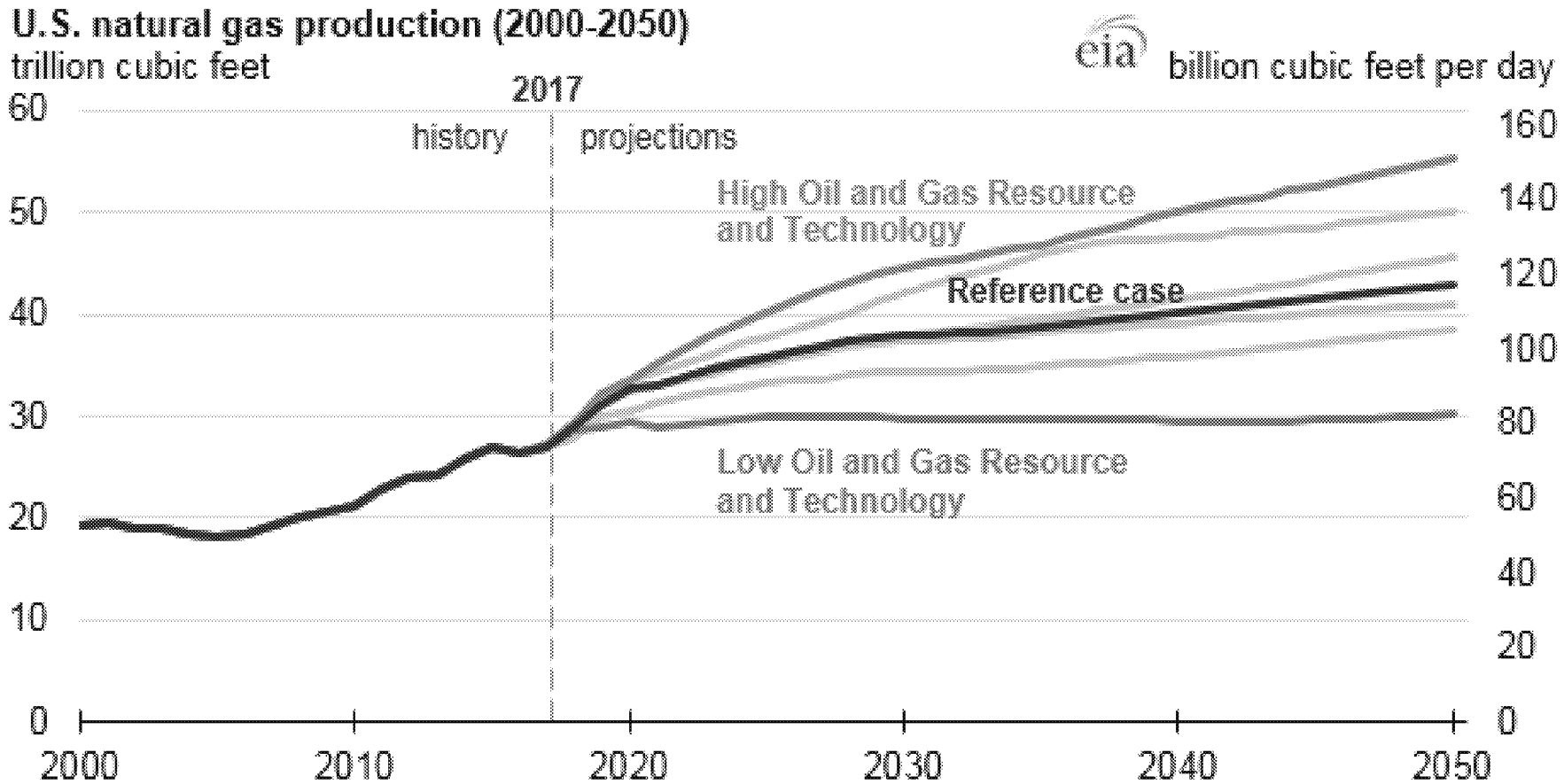
Natural Gas - Continued Growth

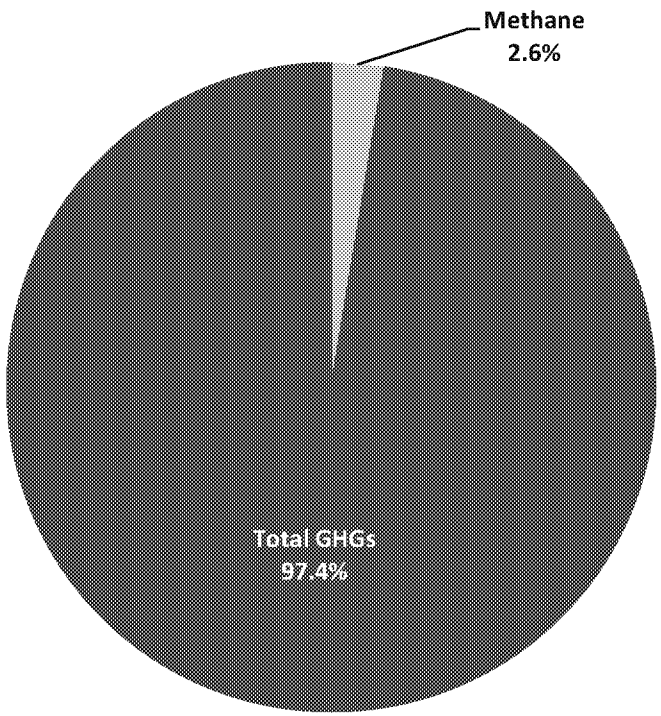
US Natural Gas Production and Consumption are Expected to Keep Rising



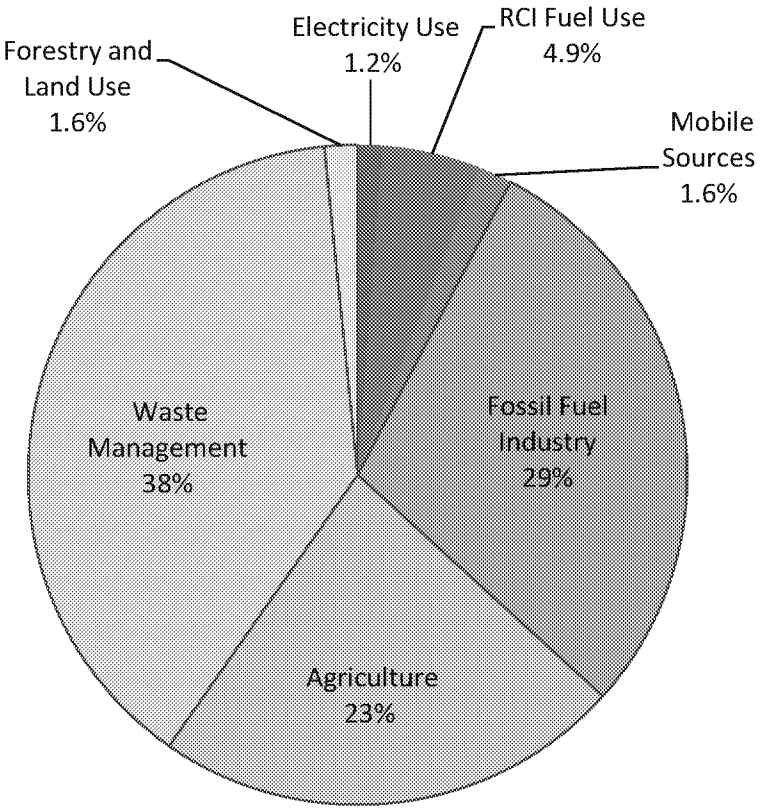
Source: U.S. Energy Information Administration, Annual Energy Outlook 2018

Methane Emissions in Maryland

All GHGs (2014)



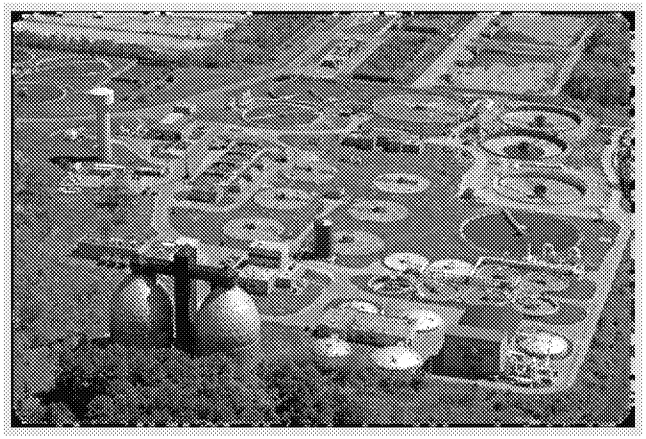
Methane Breakdown (2014)



Using CO2e conversion of 21 at 100 year

Primary Methane Source Categories in Maryland

- Leakage and venting of methane (CH4) from oil and gas fields, processing facilities, and natural gas pipelines
- Municipal and industrial landfills
- Wastewater management
- Fugitive CH4 emissions released during coal mining
- Non-energy CH4 from enteric fermentation, manure management, and agricultural soils
- Wildfires and prescribed burns



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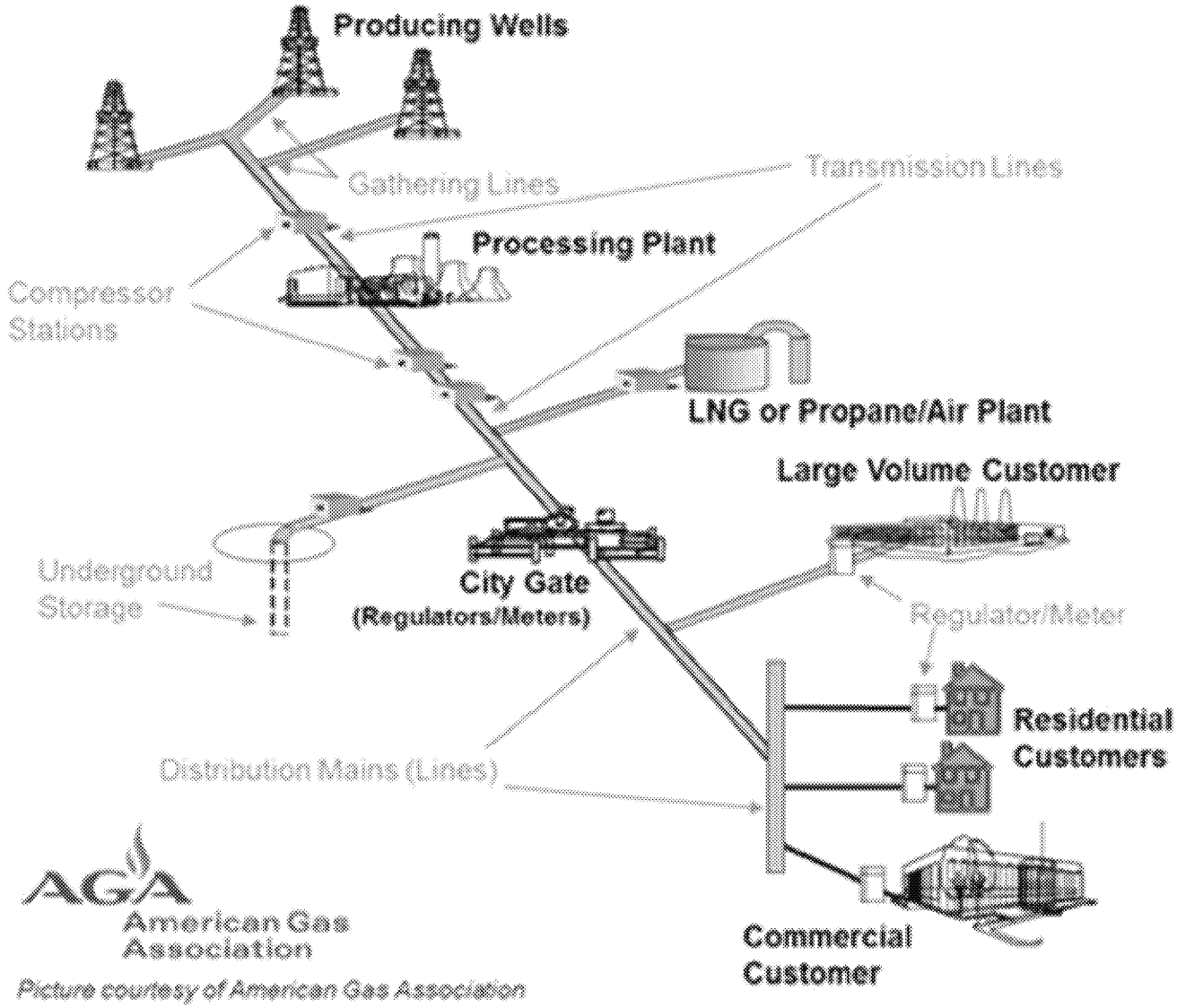
Oil and Natural Gas Industry in General



Production
- Pneumatic Controllers
- Gathering/Boosting Stations
- Tanks
- Chemical Injection Pumps

Gathering and Processing
- Reciprocating Compressors
- Centrifugal Compressors
- Gas Engines
- Blowdowns/Venting

Transmission
- Reciprocating Compressors
- Station Fugitives
- Engines
- Pipelines

Distribution
- Mishaps (Dig-ins)
- Residential
- Mains - Unprotected Steel
- Services - Unprotected Steel

Source: https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gasindustry#sources

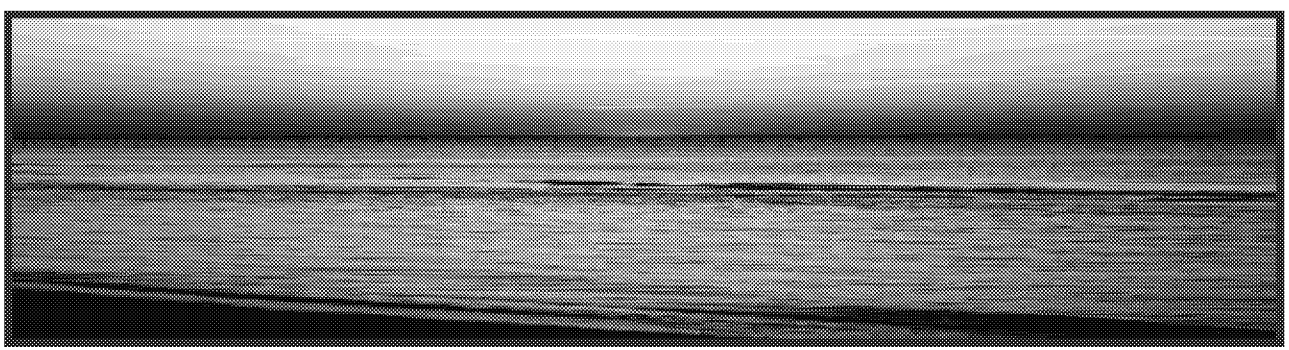
METHANE EMISSIONS MINIMIZATION PLANS

Methane Emission Minimization Plans (MEMPs)

- MEMPs will be required from all significant sources with potential methane leakage issues

- Each MEMP will include:
  - Regulatory requirements
  - Non-regulatory, data-driven requirements

- Two phases of MEMPs
  - Transmission and Gathering/Processing Sectors … First
  - Production (Wells)/Distribution Sectors… Second
  - Based upon emission reduction potential



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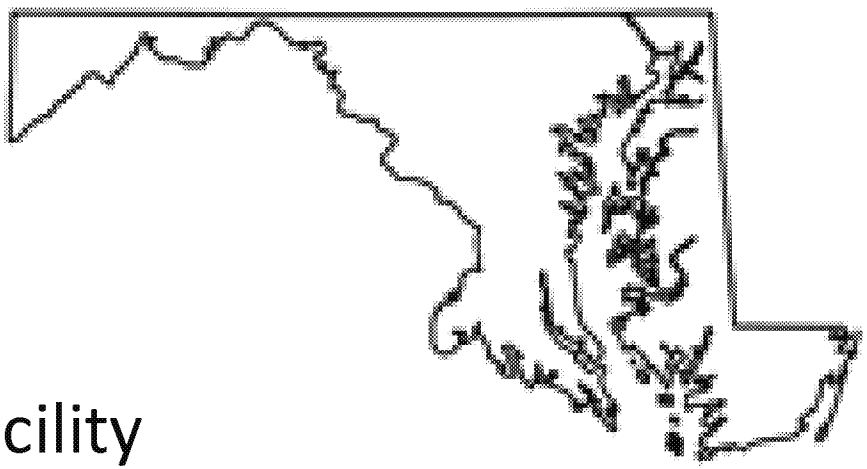
PHASE 1 - THE TRANSMISSION SECTOR

Transmission Sector - Sources Covered

- Four compressor stations (~ 1,800 in the US)
  - Dominion, Myersville
  - Texas Eastern, Accident
  - TransCanada, Rutledge
  - Transco, Ellicott City



- One underground storage facility
  - Texas Eastern, Accident
- One import and liquefaction/export facility
  - Dominion, Cove Point

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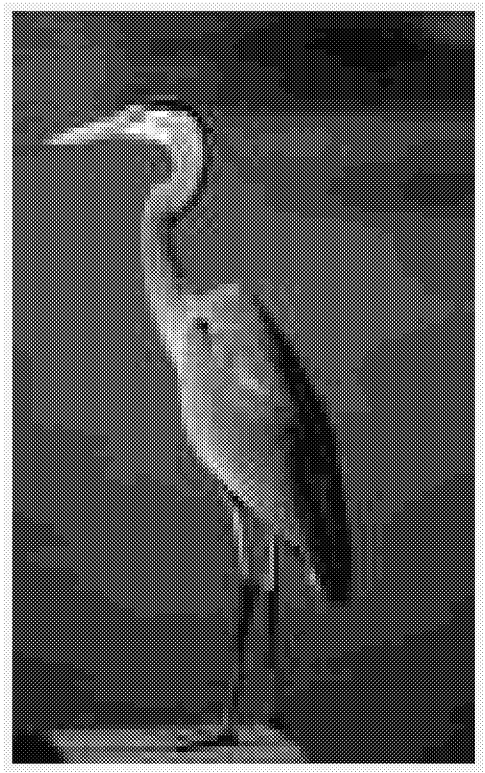
Maryland Proposed Requirements

Where did they come from?

- Built from:
  - Methane mitigation programs in other states
    - Colorado, California, Pennsylvania, New York, others
  - EPA 2016 NSPS OOOOa
  - Review of stakeholder comments
  - Meetings with each facility and community and advocacy groups



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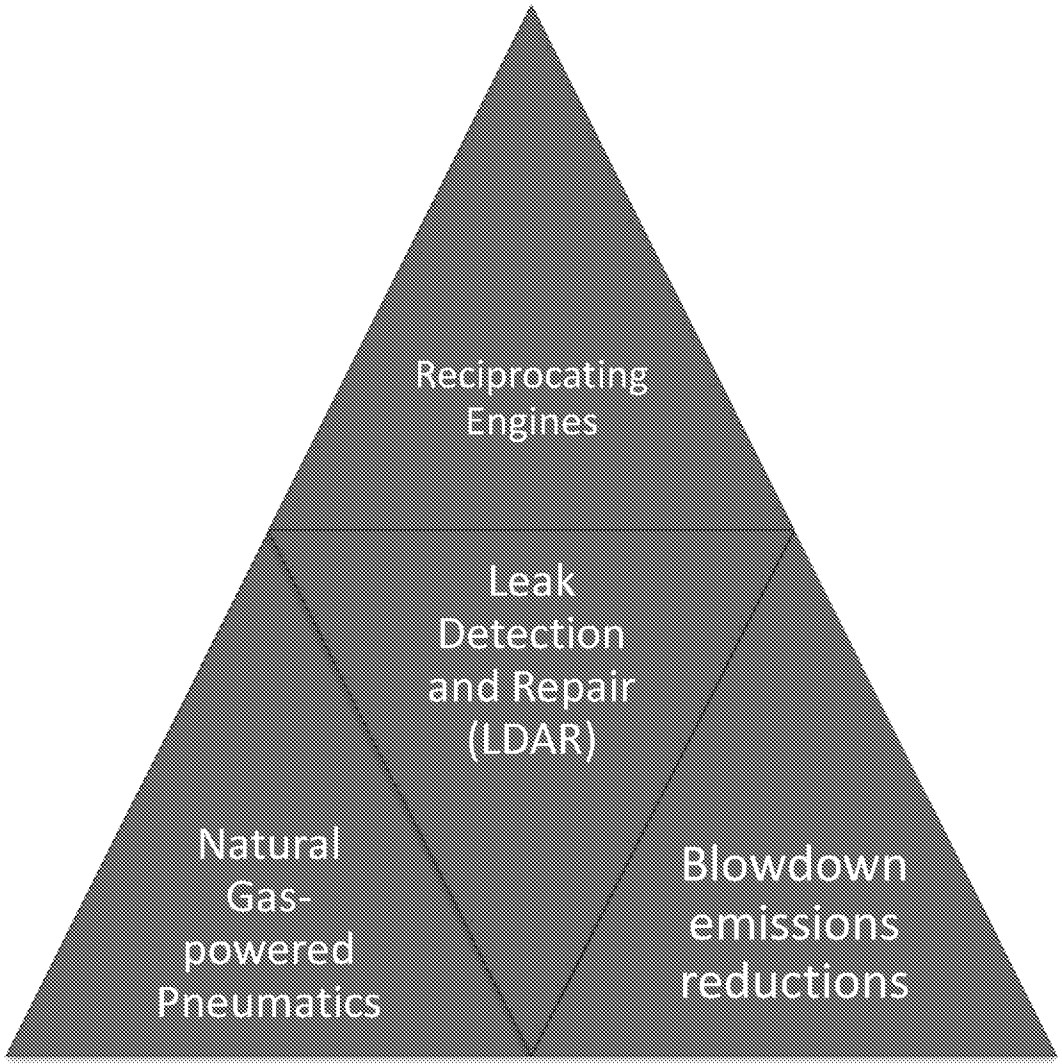
MEMP – Part I: Regulatory Requirements



Leak Detection & Repair (LDAR)

- Facilities to submit initial monitoring plan
- Initial monitoring survey due within 90 days of effective date of regulation.
  - Within 90 days at the startup of new compression
- Quarterly monitoring using Optical Gas Imaging (OGI) or Method 21
  - Exception for electric engines
  - LNG specific requirements
- Quarterly and Annual record keeping and reporting.

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MEMP – LDAR Continued

- No reduction in frequency of quarterly survey proposed.
- Repairs should be made and certified within 30 days of discovering a leak
- Delay of Repair (DOR) provisions such as: requires a station blowdown or unsafe to shutdown

(5) Repair Requirements.

(a) Any leak found shall be successfully repaired or removed from service within 30 calendar days of initial leak detection.

(b) Successful repair means confirmed to be under the fugitive leak threshold by passing a bubble test, being under 500 ppm with Method 21 or no visible emissions with an optical gas imaging (OGI) camera.

(c) A delay of repair may be granted by the Department when the owner or operator can provide proof that:

(i) The parts or equipment required to make necessary repairs will exceed greater than 30 days to deliver and have been ordered;

(ii) Repairing a leaky component is technically infeasible;

(iii) The repair requires a vent or compressor station blowdown; or

(iv) The repair is unsafe to repair during the operation of the unit.

(d) Leaking components under the delay of repair shall be clearly marked and the repair or replacement of leaking component or equipment must be completed during the next planned compressor station shutdown, vent blowdown, or within 7 days after the owner or operator receives parts or equipment needed to fix leaking component or equipment.

B. Affected facilities that are natural gas compressor stations and natural gas underground storage facility with a potential-to-emit equal to or less than 25,000 metric tons of CO_2 equivalent per year, shall comply with the following leak detection and repair requirements:

DRAFT - FOR DISCUSSION PURPOSES ONLY

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MEMP – Pneumatic Devices

- Bleed rate cannot exceed 6 standard cubic feet per hour
- Pneumatic devices will be subject to LDAR
- Additional requirement: Beginning Jan. 1, 2022 switch to electric or compressed air, or use vapor collection

B. Beginning January 1, 2022, each natural gas-powered pneumatic device shall:
(1) Collect all vented natural gas using the use of a vapor collection system; or
(2) Use compressed air or electricity to operate.

DRAFT - FOR DISCUSSION PURPOSES ONLY

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MEMP – Reciprocating Engines

- Rod packing flow rate required to be measured annually, or
- Vented gas is routed to a vapor control device and utilized

A. Each reciprocating natural gas compressor and components at an affected facility shall comply with the leak detection and repair requirements specified in Regulation .03 of this chapter.

B. Control Measures.

(1) Beginning January 1, 2021, compressor vent stacks used to vent rod packing/seal emissions shall be controlled with the use of a vapor collection system as specified in Regulation .06 of this chapter; or

(2) A reciprocating natural gas compressor with a rod packing/seal with a measured emission flow rate greater than [0.51 – 2] standard cubic feet per minute (scfm), or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by [0.51 – 2] scfm, shall be successfully repaired or replaced within 30 calendar days from the date of the initial emission flow rate measurement.

C. The reciprocating natural gas compressor rod packing/seal emission flow rate through the rod packing/seal vent stack shall be measured annually by April 1st of each year beginning in 2021 through direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is operating at normal operating temperature.

DRAFT – FOR DISCUSSION PURPOSES ONLY

MEMP – Blowdown Emissions

Require Blowdown Events to be Reported

- Affected facilities shall notify the Department prior to any planned blowdown event

- All methane emissions from blowdown events shall be reported to the Department annually by April 1st

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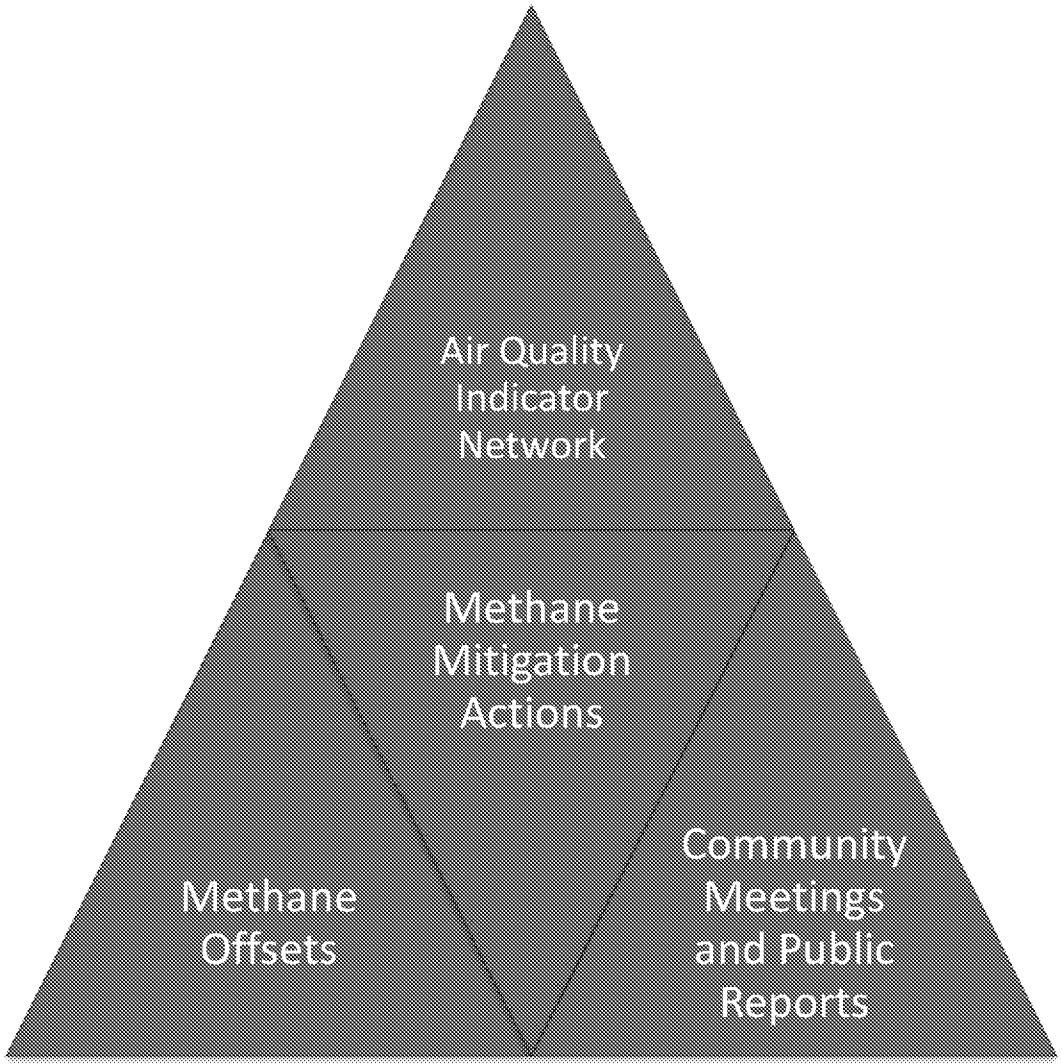
MEMP - Data Collection and Reporting

- Extensive data collection and reporting will be required
- To be harmonized with other federal and state data collection and reporting requirements
- Annual emission report
- Transparency is a priority … linked to community partnership processes required in the non-regulatory, data-driven requirements to be discussed later

MEMP – Part II
Data-Driven Partnership Agreements



Emerging Emission Reduction Opportunities

Company will voluntarily review and as appropriate implement emerging methane mitigation technologies and practices including, but not limited to:

- Blowdown venting methane emission reductions;
- Install lean burn compressor;
- Convert natural gas-driven chemical pumps;
- Replace bi-directional orifice meter with ultrasonic meters;
- Use add-on controls to reduce emissions from pneumatics;
- Move in fire gates at compressors;
- Test and repair pressure safety valves; and
- Use of YALE closures for emergency shutdown testing

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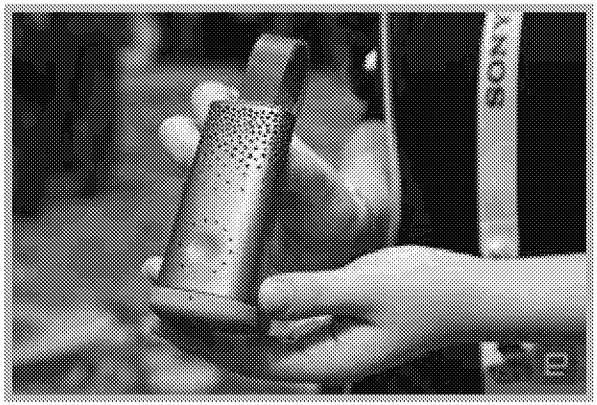
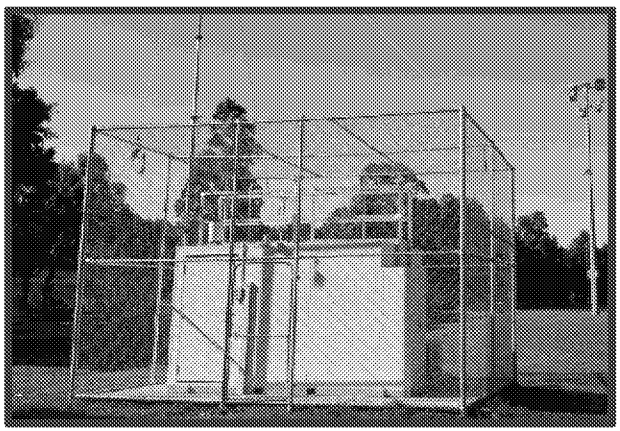
Support an Air Quality Indicator Network

- Companies to work with community to develop an air quality monitoring network
  - Cost not to exceed $100,000 over 5 years
  - Focused primarily on other air pollutants … not methane
  - Expected to focus on low-cost sensors

- Major comments from communities about air quality and public health protection around facilities

- Expectation is that emissions from well run facilities will not result in unhealthy levels of air pollution off site





Residual Methane Offset Program

- Recognize that this proposal is controversial
  - Looking for comments from all on this piece
  - Builds from MDE best practices proposal before fracking ban was finalized
  - Landfill methane capture as an example of an available offset (MD approved an offset project in 2017)
- Designed to provide major incentive to minimize leaking methane emissions - less fugitive emissions … less offset costs
- Preference for methane offsets but reductions of other GHG emissions or other projects that are beneficial to local communities could be used
  - Linkage to RGGI and national and international offset markets
- MDE will maintain a list of potential offset opportunities that can be considered by the company
- Cost cap of 5-year average annual cost of no more than $5000

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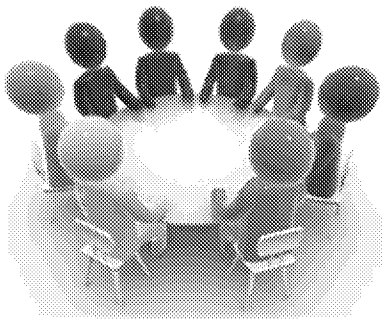
Community Meetings and Reporting

- Facilities should work with local communities to establish meetings throughout each year



- Facilities will submit a comprehensive analysis of emission reductions achieved under the MEMP as required in new regulations

- MDE to monitor … All parties expected to behave … if not, MDE can waive community meeting provision

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PHASE 2 - ADDITIONAL METHANE SOURCES UNDER REVIEW

Other Potential Sources of Leaking Methane Emissions

- Production/Fracking - In 2017, Maryland passed a law establishing a ban on hydraulic fracturing in the state
- MDE received significant comment and preliminary data pushing for making sure that methane emissions from existing wells and the distribution sector are minimized
- This effort on wells and the distribution sector will be the focus of phase 2 of this effort

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Distribution Sector

Provides residential, commercial, and industrial customers with NG services

- Several Local Distribution Utility Companies (LDU) operate in Maryland
  - LDU connected to interstate pipelines via 7 primary interstate pipelines
  - 2014 Inventory estimates over 7,500 miles of pipeline
  - Approximately 600,000 services supplied
  - Natural gas is also stored underground to allow supplies to be held and released to meet times of peak demand

Suppliers participating in the distribution sector are licensed by the MD Public Service Commission (PSC) and comply with the law, and MD PSC regulations.

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Distribution Sector Challenges

There is a significant amount of public concern over natural gas production and distribution

Moving forward, LDUs are being pushed by the public, regulatory agencies & often their internal policies to :

- Exhibit a high degree of environmental stewardship
- Maintain systems effectively and aggressively
- Effectively use advanced measurement and monitoring technology
- Minimize costs and reduce any increase in charges to the customers
- Meet all (not just air) regulatory requirements from local, state and federal agencies

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Distribution Sector - Potential Sources in Maryland

- Pipeline Distribution
  - Baltimore Gas and Electric
  - Chesapeake Utilities Corporation
  - Columbia Gas
  - Easton Utilities
  - Elkton Gas
  - Eastern Shore Natural Gas
  - Penn Fuel Gas, Inc.
  - Washington Gas
  - UGI Utilities

- Natural Gas Storage (Peak Stations)
  - Baltimore Gas and Electric - Spring Gardens, Baltimore, MD
  - Washington Gas - Rockville Station, Rockville, MD

- In most cases, it appears that there are significant ongoing efforts to minimize leakage as leakage results in lower profits

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Distribution Sector

Aging Pipes

- There is widespread consensus that aging cast iron and unprotected steel pipelines within older natural gas distribution systems are subject to more leakage
  - Older pipes … More leaks

- To avoid leaking emissions, product loss, and for safety, industry best management practices include:
  - Replacement with plastic or protected steel
  - Flexible insert liners
  - Leak volume assessment

- The rate at which replacement is occurring differs significantly between suppliers

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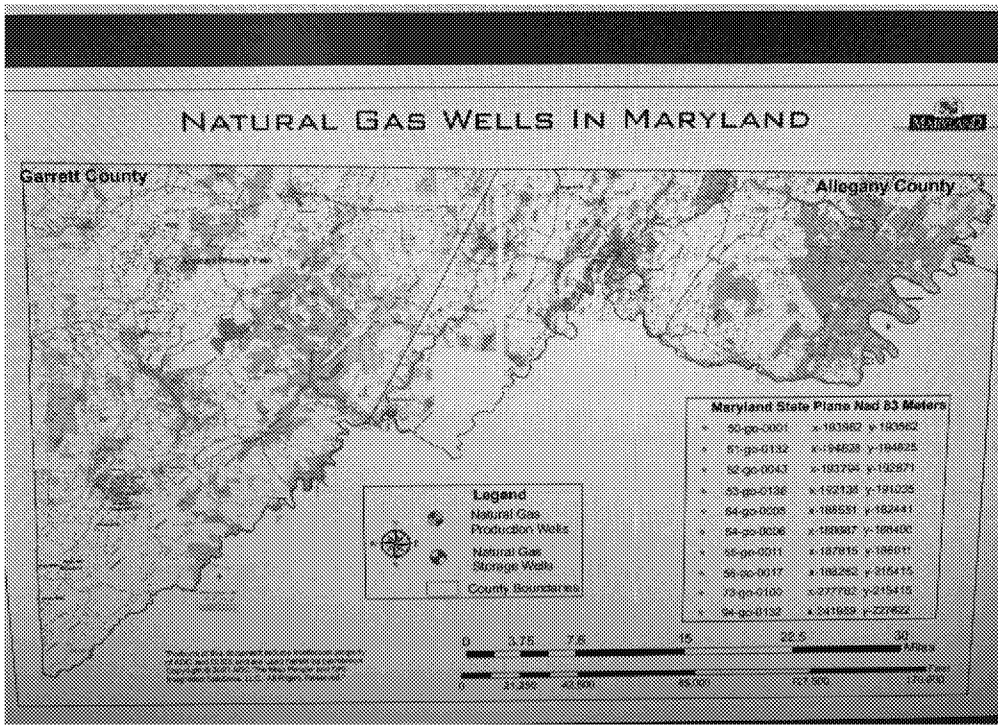
Production/Existing Wells

- 10 active wells in western Maryland
- Permitted though MDE Land Mining program
- Storage wells at Texas Eastern regulated with Transmission sector
- Less than 1% of 2014 GHG Inventory



https://mde.maryland.gov/programs/LAND/mining/Documents/www.mde.state.md.us/assets/document/mining/NaturalGasWellLocationMap.pdf

HOW DO MARYLAND'S EFFORTS COMPARE TO OTHER LEADERSHIP STATES

Proposed MD Requirements Compared to Others

	MD - MEMP	EPA - 2016 NSPS OOOOa	CARB - Oil and Gas	CO – Regulation 7	NY – Oil and Gas Stakeholder Outline 11/8/2018
Applicability	Gathering and Processing, Transmission and Storage … Distribution (Phase 2)	Production, Gathering and Processing, Transmission and Storage	Production, Gathering and Processing, Transmission and Storage	Production, Gathering and Processing	Production, Gathering and Processing, Transmission and Storage, Distribution
LDAR in Transmission and Storage	Quarterly monitoring using OGI or Method 21. Repairs within 30 days of leak discovery	Quarterly monitoring using OGI or Method 21. Repairs within 30 days of leak discovery	Quarterly monitoring using Method 21. Frequency reduces based on leak %. Repairs within 30 days of leak discovery	Quarterly monitoring using OGI or Method 21. Repairs within 30 days of leak discovery	Quarterly monitoring using OGI or Method 21. Repairs within 5-30 days of leak discovery

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Proposed MD Requirements Compared to Others - Continued

	MD - MEMP	EPA - 2016 NSPS OOOOa	CARB - Oil and Gas	CO – Regulation 7	NY – Oil and Gas Stakeholder Outline 11/8/2018
Pneumatic Controllers	- Bleed rate < 6 scfh - In 2022, switch to electric or compressed air or utilize vapor control	- Bleed rate < 6 scfh	- Bleed rate < 6 scfh - Switch to electric or compressed air or utilize vapor control	- Bleed rate <6 scfh; no-bleed where grid power (if placed in service on/after 5/1/2014)	- Bleed rate < 6 scfh
Recip engines rod replacement	Measure rod packing annually and replace at emission threshold or utilize vapor control	Every 3 years or 26,000, whichever is sooner	Measure rod packing annually and replace at emission threshold or utilize vapor control	Every 3 years or 26,000, whichever is sooner	Every 3 years or 26,000, whichever is sooner or utilize vapor control

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Proposed MD Requirements Compared to Others - Continued

	MD - MEMP	EPA - 2016 NSPS OOOOa	CARB - Oil and Gas	CO – Regulation 7	NY – Oil and Gas (Under development) Stakeholder Outline 11/8/2018
Blowdown events at compressor stations	Report to State	No requirement	No requirement	No requirement	Use inline pipeline compressors to reduce the pressure where technically feasible
Distribution sources	Under further review	No requirement	No requirement	No requirement	Investigating LDAR at metering and regulating stations.

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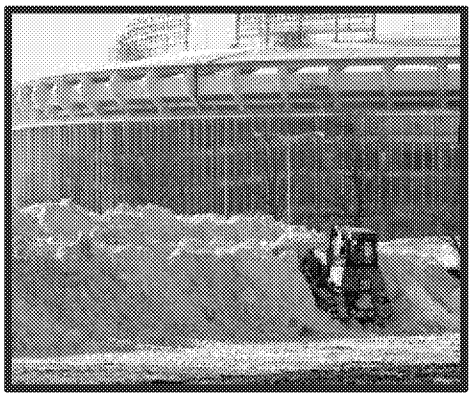
Schedule

- Begin to work with affected sources on concepts in the MEMP … Now
- Summer - Draft Regulations and final stakeholder meeting
- Fall - Advisory Council and Proposal in Maryland Register
- Late 2019/Early 2020 - Final adoption



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Other Methane Issues of Potential Interest

- Maryland is working with approximately 15 other states to challenge backsliding on federal methane reduction rules for new and existing sources in the oil and gas sector

- Same for federal landfill rules
- Maryland is also working on understanding the life-cycle of emission changes associated with natural gas
  - Looking at in-state and upstream sources

QUESTIONS?

DISCUSSION

Message

From: Vyas, Himanshu [vyas.himanshu@epa.gov]
Sent: 7/5/2017 1:46:12 PM
To: Lawrence, Rob [Lawrence.Rob@epa.gov]; Kenney, James [Kenney.James@epa.gov]; Beeler, Cindy [Beeler.Cindy@epa.gov]
CC: Kaleri, Cynthia [kaleri.cynthia@epa.gov]; Larson, Darrin [Larson.Darrin@epa.gov]; Thompson, Steve [thompson.steve@epa.gov]; Hambrick, Amy [Hambrick.Amy@epa.gov]; Harrison, Ben [Harrison.Ben@epa.gov]; Payne, James [payne.james@epa.gov]; Seager, Cheryl [Seager.Cheryl@epa.gov]; baltera, danielle [baltera.danielle@epa.gov]; duke, gerallyn [duke.gerallyn@epa.gov]; Smith, Claudia [Smith.Claudia@epa.gov]; Topinka, Natalie [topinka.natalie@epa.gov]
Subject: RE: Washington Post - Federal court blocks oil/gas methane action

Ex. 5 Deliberative Process (DP)

Here is BNA's coverage:

Court Revives EPA Methane Regulation on Oil, Gas Drillers

Posted July 03, 2017, 01:32 P.M. ET

By David Schultz

A federal appeals court has revived an Obama-era EPA methane regulation on the oil and gas industry after the Trump administration tried to place it on hold.

This means oil and gas drillers may have to comply with this regulation despite earlier indications they wouldn't have to.

The regulation at issue requires oil and gas drillers to boost their monitoring for leaking methane, a potent greenhouse gas. It was enacted in the final months of the Obama administration as part of its Climate Action Plan.

Earlier this year, the Environmental Protection Agency announced that it will reconsider this regulation and moved to place its upcoming compliance deadlines on hold. A three-judge panel in the U.S. Court of Appeals for the D.C. Circuit, however, ruled July 3 that the EPA could not impose a three-month delay on implementing the regulation, which means its upcoming compliance deadlines may go into effect after all.

Detailed coverage:
http://news.bna.com/deln/DELNWB/split_display.adp?fedfid=115550562&vname=dennotallissues&jd=0000015d09f8da49ad5f49fe3a0c0000&split=0

Air Pollution
Court Rebukes EPA for Shelving Obama-Era Methane Regulation

By Jennifer A. Dlouhy (Bloomberg) and Andrew Harris (Bloomberg), and David Schultz (Bloomberg BNA)

A federal appeals court rebuked the EPA for unilaterally suspending Obama-era methane emissions regulations, criticizing the "flimsiness" of its arguments and bringing the regulations back into effect.

The Washington-based panel's 2–1 majority July 3 called the Environmental Protection Agency's move both unauthorized and unreasonable. It granted a request from six environmental groups to overturn an EPA decision that stopped enforcement of the methane regulations for three months (*Clean Air Council v. Pruitt*, D.C. Cir., No. 17-1145, 7/3/17).

The court ruling is the latest blow to President Donald Trump, who has been pushing the roll back of regulations put in place by his predecessor, Barack Obama. Courts also have delayed the president's effort to put in place a travel ban on citizens of six mostly Muslim countries and refugees.

The ruling also represents yet another surprise for oil and gas drillers. The EPA suspended the methane regulations in June, just days before compliance deadlines were to kick in. Now, less than a month later, drillers are learning they will likely have to comply with the deadlines after all.

"They were working toward complying with the rule and then it was stayed and now it's not," Kathleen Sgamma, president of the Western Energy Alliance, which represents drillers, told Bloomberg BNA. "When you're spending your resources complying with a regulation rather than going out and producing energy, that's wasted effort and wasted capital."

Methane Emissions

The rule (RIN:2060-AS30), imposed in May 2016, required oil and gas companies to find and fix leaking methane, a potent greenhouse gas shown to warm the atmosphere 84 times more than carbon dioxide when measured over two decades. It was a part of the Obama administration's climate action plan.

The rule applied to new and modified facilities, including oil and gas wells, pumps, compressors, and other equipment. The measure requires companies to upgrade equipment at the sites and better capture gas surging out of oil wells. They also have to regularly search out and repair leaks.

Oil and gas companies, especially smaller independent firms that operate low-production wells targeted in the rule, have argued that it is unnecessary because they already have an economic incentive to capture methane, the primary component of natural gas.

The independent petroleum companies Pioneer Natural Resources Co., Concho Resources Inc., Merlin Oil & Gas Inc., and others did not respond to requests for comment.

Time to Comment

At the request of several energy industry groups, the EPA said earlier this year that it would reconsider the rule and also moved to delay implementing it for 90 days while it began the reconsideration process. The agency said it agreed to reconsider the rule because the final version that the Obama administration enacted was substantially different from an earlier proposed version, which prevented regulated companies from submitting comments on it.

This is simply not true, however, said U.S. Circuit judges David Tatel and Robert Wilkins. In their joint ruling, Tatel and Wilkins said companies had ample opportunity to comment and, in fact, many did. Therefore, imposing a 90-day stay was outside the bounds of the EPA's authority, the judges said.

The judges also said, however, their ruling does not prevent the EPA from repealing the methane regulation if it goes through the proper rulemaking process.

In a dissent, Judge Janice Rogers Brown said the court should not have even heard the case because it lacks jurisdiction.

"We are reviewing the opinion and examining our options," EPA spokeswoman Amy Graham told Bloomberg BNA.

'Lacks the Authority'

Earthworks, one of the groups challenging EPA Administrator Scott Pruitt's decision to delay the methane mandates, called the ruling "a big win for public health and a wake-up call for this administration."

Earthjustice staff attorney Tim Ballo said in an e-mailed statement: "Today's ruling makes clear that Scott Pruitt lacks the authority to slam the brakes on common-sense methane pollution rules that help protect the climate and communities living near oil and gas wells."

Pruitt took aim at the measure while he was Oklahoma's attorney general, with the urging of oil and gas producer Devon Energy Corp.

He built his political career fighting federal regulations that he said usurped states' power, and joined more than a dozen lawsuits challenging EPA actions.
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To contact the reporters on this story: Jennifer A. Dlouhy in Washington at jdlouhy1@bloomberg.net; Andrew Harris in Washington at aharris16@bloomberg.net; David Schultz in Washington at dschultz@bna.com
To contact the editors responsible for this story: David Glovin at dglovin@bloomberg.net (Bloomberg) and Rachael Daigle at rdaigle@bna.com (Bloomberg BNA)

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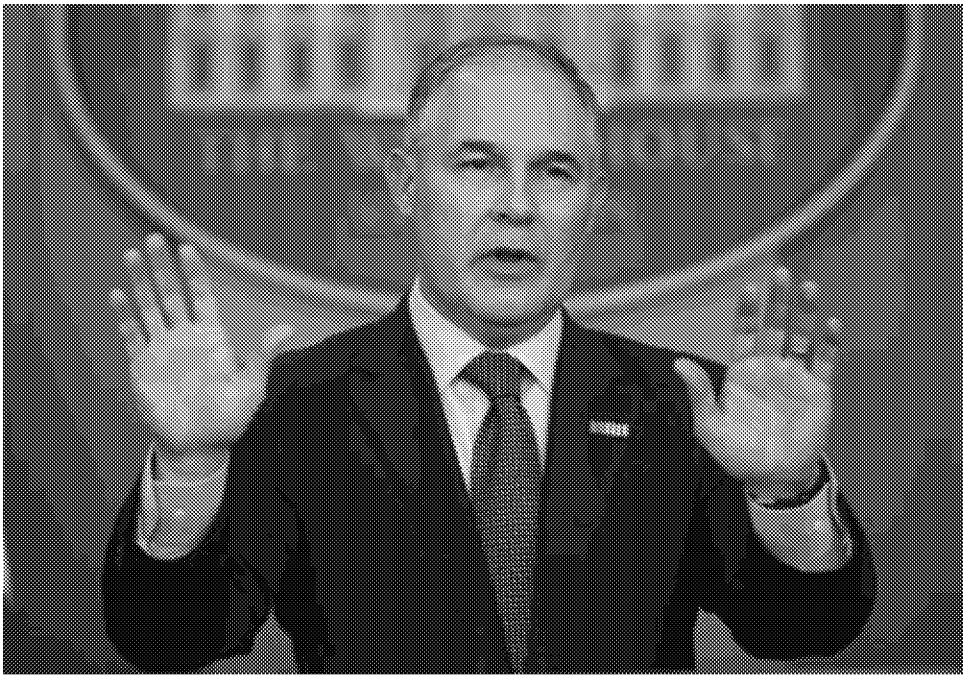
From: Lawrence, Rob
Sent: Wednesday, July 05, 2017 9:08 AM
To: Kenney, James <Kenney.James@epa.gov>; Beeler, Cindy <Beeler.Cindy@epa.gov>; Vyas, Himanshu <vyas.himanshu@epa.gov>
Cc: Kaleri, Cynthia <kaleri.cynthia@epa.gov>; Larson, Darrin <Larson.Darrin@epa.gov>; Thompson, Steve <thompson.steve@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>; Harrison, Ben <Harrison.Ben@epa.gov>; Payne, James <payne.james@epa.gov>; Seager, Cheryl <Seager.Cheryl@epa.gov>
Subject: Washington Post - Federal court blocks oil/gas methane action

Based on the correction at the bottom, I wasn't the only one confused about the 2 year versus 90 day stay that was at issue.

Ben / Jim – since I am to speak to this issue at next week's Regional Tribal Operations Committee meeting, if/when you hear from OGC/OECA what the official interpretation is, please let me know. Thanks.

Federal court blocks Trump EPA on air pollution



EPA Administrator Scott Pruitt speaks to the media during the daily briefing at the White House on June 2. A federal appeals court in Washington ruled Monday that Pruitt overstepped his authority in trying to delay implementation of a 2016 rule requiring oil and gas companies to monitor and reduce methane leaks. (Pablo Martinez Monsivais/AP)

By Juliet Eilperin and Steven Mufson July 3

An appeals court Monday struck down the Environmental Protection Agency's 90-day suspension of new emission standards on oil and gas wells, a decision that could set back the Trump administration's broad legal strategy for rolling back Obama-era rules.

In a 2-to-1 ruling, the U.S. Court of Appeals for the District of Columbia Circuit concluded that the EPA had the right to reconsider a 2016 rule limiting methane and smog-forming pollutants emitted by oil and gas wells but could not delay the effective date while it sought to rewrite the regulation.

The agency has proposed extending the initial delay to two years; the court will hold a hearing on that suspension separately.

"The court's ruling is yet another reminder, now in the context of environmental protection, that the federal judiciary remains a significant obstacle to the president's desire to order immediate change," Richard Lazarus, an environmental-law professor at Harvard Law School, said in an email.

"The D.C. Circuit's ruling today makes clear that neither the president nor his EPA administrator, Scott Pruitt, can by fiat unilaterally and instantaneously repeal or otherwise

stay the effectiveness of the environmental protection rules put into place during the Obama administration," he added.

The EPA, along with the American Petroleum Institute, had argued that the stay Pruitt imposed last month was not subject to judicial review, because it did not constitute final action on the rule. In a recent interview with The Washington Post, Pruitt said, "Just because you provide a time for implementation or compliance that's longer doesn't mean that you're going to necessarily reverse or redirect the rule."

But the court rejected that interpretation, writing, "EPA's stay, in other words, is essentially an order delaying the rule's effective date, and this court has held that such orders are tantamount to amending or revoking a rule."

Appointees of Presidents Bill Clinton and Barack Obama, David S. Tatel and Robert L. Wilkins, joined in the majority, while Janice Rogers Brown, an appointee of President George W. Bush, dissented.

The ruling could affect myriad agencies that have delayed the Obama administration's regulations, some for long periods. And it underscores the extent to which activists are turning to the courts to block President Trump's most ambitious policy shifts.

Last month, for example, the Interior Department announced that it would delay compliance with a rule finalized in November that would limit methane burned off from drilling operations on federal and tribal lands. And the Labor Department just proposed delaying until December a rule that was set to take effect July 1 that would require companies to electronically report injuries and illnesses.

"The court says you can consider changing the rules but you have to do it the normal way, with a comment period," said David Doniger, director of the climate and clean-air program at the Natural Resources Defense Council. "You can't yank it out of existence on your say-so."

Lazarus added, "Changing the rules midstream can occur only after a thorough administrative review, including public notice and opportunity to comment, that ensures that there are good reasons for the change, backed up by sound policy and science."

EPA spokeswoman Amy Graham said in an email that the agency was "reviewing the opinion and examining our options" in light of the decision.

The rule the EPA had sought to suspend had imposed the first-ever federal limits on leaks of methane, a potent greenhouse gas, from oil and natural-gas wells. It applied only to new or modified wells. The agency had previously projected that the rule would prevent 11 million metric tons of carbon-dioxide-equivalent emissions by 2025. Doniger said it would, so far, apply to about 11,000 wells drilled since September 2015.

Many of the industry's largest companies have been working with the Environmental Defense Fund to measure leakage through the natural-gas system, including wells, pipelines, power plants and homes. The EDF said that reducing leaks would keep large quantities of smog-forming volatile organic compounds, cancer-causing benzene, and methane from being emitted into the air.

Pruitt has moved to suspend or revoke several other rules adopted during the Obama administration, including a two-year delay on a regulation aimed at minimizing chemical accidents like the 2013 ammonium nitrate explosion at a plant in West, Tex.

Monday's court ruling was sharply worded at points, with the judges dismissing "the flimsiness" of the EPA's "claim that regulated entities had no opportunity to comment" on one aspect of the methane rule.

"The administrative record thus makes clear that industry groups had ample opportunity to comment on all four issues on which EPA granted reconsideration, and indeed, that in several instances the agency incorporated those comments directly into the final rule," the judges wrote.

Reid Porter, a spokesman for the American Petroleum Institute, said in an email that the suspension of the rule would have allowed for "regulatory certainty" and that an EPA report in March concluded that methane emissions from petroleum production had already declined roughly 8 percent from 2014 levels.

"API supports revision of the 2016 New Source Performance Standards, and we are hopeful that the eventual outcome recognizes the science, allowing for revisions to the flawed rule," Porter said.

Even as one aspect of the administration's push to promote domestic energy production faced a legal setback Monday, it advanced on a separate front. The Interior Department launched a new offshore-leasing planning process for 2019 to 2024, a move that could open up new areas for drilling in the Arctic, Atlantic and Pacific oceans, as well as the Gulf of Mexico.

In a Federal Register notice published Friday, the Interior Department invited public comment on a plan that would "replace the 2017-2022 Program" established during the Obama administration and represent "a key aspect of the implementation of President Donald J. Trump's America-First Offshore Energy Strategy."
Brady Dennis contributed to this report.

Correction: *An earlier version of this article said that the court struck down a two-year delay of the 2016 methane rule, not the EPA's initial 90-day delay of the rule.*

Rob Lawrence
Region 6
Policy Advisor - Energy Issues
214.665.6580

Message

From: Hambrick, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=787B0A3376944FCABAED4F018432CF44-AHAMBRIC]
Sent: 4/19/2017 6:27:00 PM
To: Keith E Cottrill [keith.cottrill@ilandv.com]
CC: ian@mgmservicesinc.com; Ian McGill [ian.mcgill@mgmmedia.co]
Subject: RE: Well Inclusion Interpretation

Keith-

I can only assume at this time that the comments would be put in a public docket (like we do during regular rulemakings), but I can't say for sure. Once comments are in a docket, anyone can access them.

Thanks for the links.

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Keith E Cottrill [mailto:keith.cottrill@ilandv.com]
Sent: Wednesday, April 19, 2017 2:18 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Cc: ian@mgmservicesinc.com; Ian McGill <ian.mcgill@mgmmedia.co>
Subject: RE: Well Inclusion Interpretation

Amy,

Thank you VERY MUCH.

Will the public opinions or comments be made available during the review or after the end of 90 days?

For your information and data, here's a link to the last two incidents in Louisiana involving GAS LINES within the past 6 months that involved crews and lose of life.

https://www.rt.com/usa/377000-paradis-pipeline-explosion-phillips66/

http://www.ksla.com/story/35182528/well-tank-explosion-kills-worker-hurts-two-others-in-desoto

The first one was after the purchase of the facility within one month of the incident.

In both cases our system could have performed a very detailed inspection of the facilities to detect gas leaks with a system that enables crews accomplish the inspections while a SAFE distance from the facilities with the ONLY DRONE based system in the United States. There are less than 10 cameras in existence in the US and we have access to two of these cameras. So we are pretty confident that no form of inspection was accomplished at these sites with a proven system before these men were sent inton harms way.

Keith E Cottrill, RPL #78089
Innovative LAND Ventures

(318)573-9306
"Notice of Confidentiality: This e-mail, and any attachment hereto, is intended for use only by the addressees named herein and may contain legally privileged and/or confidential information. It's STRICTLY for the use of the ADDRESSEE and should not be disseminated to anyone else without consent of the SENDER. If you are not the intended recipient of this e-mail, you are hereby notified that any dissemination, distribution or copying of this e-mail, and any attachment hereto, is strictly prohibited. If you have received this e-mail in error, please immediately notify me by e-mail (by replying to this message) and permanently delete the original and any copy and destroy any printout thereof. Thank you for your cooperation with respect to this matter."

On Wed, 19 Apr 2017 16:44:53 +0000, "Hambrick, Amy" <Hambrick.Amy@epa.gov> wrote:

Keith,

I thought you would want to know this was released today:

https://www.epa.gov/newsreleases/epa-reconsider-oil-and-gas-rule

Amy

Amy Hambrick

U.S. Environmental Protection Agency

(919)541-0964

From: Keith Cottrill [mailto:keith.cottrill@ilandv.com]
Sent: Thursday, April 13, 2017 2:12 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>; ian@mgmservicesinc.com
Cc: Thompson, Lisa <Thompson.Lisa@epa.gov>; Dewees, Jason <Dewees.Jason@epa.gov>
Subject: RE: Well Inclusion Interpretation

Amy,
Great hearing from you. I'm on the road, you have a nice holiday weekend and I would like to try and call you Monday.

On April 13, 2017 11:19:06 AM CDT, "Hambrick, Amy" <Hambrick.Amy@epa.gov> wrote:

HI Keith and Ian,

Nice to hear from you again. Yes, as you have alluded to there has been some activity you've probably read in the news regarding the oil and gas NSPS. Specifically, On March 28, 2017, the EPA was directed to review this regulation to ensure the rule promotes clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth and prevent job creation. On April 4, 2017, the EPA published an announcement in the Federal Register to review the 2016 Oil and Natural Gas NSPS for New, Reconstructed, and Modified Sources. We continue to look forward to keep communication open with stakeholders. Just let me know what you are thinking (e.g. phone call, in person meeting, etc.). Besides what is written in the EO and FR notice, I don't have additional information but we are always open to having engaging conversations.

Regards,

Amy

Amy Hambrick

U.S. Environmental Protection Agency

(919)541-0964

From: Keith E Cottrill [mailto:keith.cottrill@ilandv.com]
Sent: Wednesday, April 12, 2017 5:46 PM
To: ian@mgmservicesinc.com; Dewees, Jason <Dewees.Jason@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: RE: Well Inclusion Interpretation

Amy,

Hi, this is Keith and Ian, we had some very nice conversations last year with the Quad Oa regulation and we understand that the EPA has had some changes and probably new direction. As we talked last year we tried to develope a mutual working relationship between you and the Oil and Gas Industry and we hope we can restart some of those conversations from last year.

Please let us know if we can open up those lines of communication.

Keith E Cottrill, RPL #78089
Innovative LAND Ventures
(318)573-9306
"Notice of Confidentiality: This e-mail, and any attachment hereto, is intended for use only by the addressees named herein and may contain legally privileged and/or confidential information. It's STRICTLY for the use of the ADDRESSEE and should not be disseminated to anyone else without consent of the SENDER. If you are not the intended recipient of this e-mail, you are hereby notified that any dissemination, distribution or copying of this e-mail, and any attachment hereto, is strictly prohibited. If you have received this e-mail in error, please immediately notify me by e-mail (by replying to this message) and permanently delete the original and any copy and destroy any printout thereof. Thank you for your cooperation with respect to this matter."

On Wed, 26 Oct 2016 22:02:43 +0000, "Hambrick, Amy" <Hambrick.Amy@epa.gov> wrote:

> Hi Ian,

Thanks for your email. You make numerous points in your email but I think it is boiling down to this:

OOOO does not have a fugitives emissions program for new, modified, reconstructed sources between the date range in the rule (2011 and 2015). OOOOa fugitive emissions requirements for well sites includes both oil and gas well sites for new, modified, reconstructed sources after the specified date in the rule (2015). For OOOOa, well sites include production and injection based on the definition. Also for purposes of the fugitives program, well site also includes a separate tank battery. Fugitive emissions requirements at 60.5397a are not applicable to well sites consisting only of one or more wellheads (e.g. Christmas tree) (see §60.5365a(i)(2)). Regarding a well that is shut in… if it triggers OOOOa at some point in time, then stops production at a later point, the rule doesn't seem to provide as "out" so to speak of the fugitives program after shut in. I think it would still be "in" the program. But let me look more into that one more…

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

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

Let's talk more as needed,

Amy

Amy Hambrick

U.S. Environmental Protection Agency

(919)541-0964

From: Ian McGill [mailto:ian@mgmservicesinc.com]
Sent: Thursday, October 13, 2016 5:55 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>; Dewees, Jason <Dewees.Jason@epa.gov>
Cc: keith.cottrill@ilandv.com
Subject: Well Inclusion Interpretation

Amy and Jason,

Sorry to keep taking you down the same old path, but we are looking once more for some clarification between Quad O, Oa, and Part 60.

Quad Oa covers specific sources that were not covered in 2012's Quad O, and the updated Part 60 rules brought everything to 2016. Most of the analysis and industry chatter revolves around fractured wells and compressor/processing plants, but the updated regulations look to tie together the VOC's, GHG's, pollutants, and specifically methane from all sources, including low production wells.

Going through the provisions below, and reading through the preamble to Quad Oa, it appears that all production sites and facilities are included in the combined rules of Quad O, Quad Oa, and Part 60. Oil production from the well, extending to the transmission pipeline, is referenced repeatedly in the preamble and referred to specifically in many places, including 60.5365a and 60.5435a.

There is an exemption for a wellhead as noted on page 35861 of the preamble under paragraph j. Definition of Well Site, which states, our intent is not to have well sites that only contain one or more wellheads subject to fugitive emissions standards. To make this

intent more explicit, we have added language to § 60.5365a(i)(2) to this effect.

The definition of a wellhead is as follows:

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Therefore, if we follow the definitions through the document, in combination with the exceptions, it appears that it is not only fractured and refractured wells that are included, but crude oil wells also (refer to part 60.5430a (page 35933), below).

Our interpretation leads us to believe the following; that all production wells, oil and gas, are included in the LDAR rules for inspection, the exception being any site with a non-production wellhead as defined above. So a well that is shut-in would not be affected, but any well that is producing gas or oil, or has not been shut-in (i.e. a well with a pump jack that is or is not running) would be included, either as a stationary source under Part 60.2, or under another part of the regulation as noted herein.

If you have time, please let us know if you concur with our interpretation.

Once again, thanks for your help.

Ian McGill

In section II. General Information, A. Executive Summary, of Quad Oa, we see the following:

2. Summary of 40 CFR Part 60, Subpart OOOOa Major Provisions

The final requirements include standards for GHG emissions (in the

form of methane emission limitations) and standards for VOC emissions. The

NSPS includes both VOC and GHG emission standards for certain new,

modified, and reconstructed equipment, processes, and activities across the oil

and natural gas source category. These emission sources include the following:

• Sources that are unregulated under the current NSPS at subpart OOOO

(hydraulically fractured oil well completions, pneumatic pumps, and

fugitive emissions from well sites and compressor stations);

• Sources that are currently regulated at subpart OOOO for VOC, but not for

GHGs (hydraulically fractured gas well completions and equipment leaks at

natural gas processing plants);

• Certain equipment that is used across the source category, for which the

current NSPS at subpart OOOO regulates emissions of VOC from only a

subset (pneumatic controllers, centrifugal compressors, and

reciprocating compressors), with the exception of compressors located at well

sites.

In the sections below, still from Quad Oa, the General Provisions refer back to Title 40,

Protection of Environment, Part 60 (§§ 60.1 to 60.499)

Revised as of July 1, 2016

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in

§§ 60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning

given them in the Act, in subpart A or subpart VVa of part 60; and the

following terms shall have the specific meanings given them.

60.5430a (page 35933)

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of

custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to,

but do not include, the local distribution company custody transfer station.

§ 60.5365a Am I subject to this subpart?

§ 60.5365a

(i) Except as provided in § 60.5365a(i)(2), the collection of fugitive emissions components at a well

site, as defined in § 60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

Finally, in Title 40, Part 60,

Title 40

Protection of Environment

Part 60 (§§ 60.1 to 60.499)

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as

follows:

Affected facility means, with reference to a stationary source, any apparatus

to which a standard is applicable.

Stationary source means any building, structure, facility, or installation

which emits or may emit any air pollutant.

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Sent from my Android device with K-9 Mail. Please excuse my brevity.

Message

From: Marsh, Karen [Marsh.Karen@epa.gov]
Sent: 10/31/2018 5:21:13 PM
To: Garwood, Gerri [Garwood.Gerri@epa.gov]; Shappley, Ned [Shappley.Ned@epa.gov]; Dewees, Jason [Dewees.Jason@epa.gov]
CC: Hambrick, Amy [Hambrick.Amy@epa.gov]; Witt, Jon [Witt.Jon@epa.gov]; Witosky, Matthew [Witosky.Matthew@epa.gov]; Macpherson, Alex [Macpherson.Alex@epa.gov]; Hoffmann, Jucilene [hoffmann.jucilene@epa.gov]; Miller, Elizabeth [Miller.Elizabeth@epa.gov]
Subject: FW: New A&WMA Article on LDAR
Attachments: LDAR Schwietzke.pdf

FYI...

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Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Eisele, Adam
Sent: Wednesday, October 31, 2018 1:06 PM
To: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Marsh, Karen <Marsh.Karen@epa.gov>
Subject: New A&WMA Article on LDAR

Some notable authors we work with regularly in OAP.

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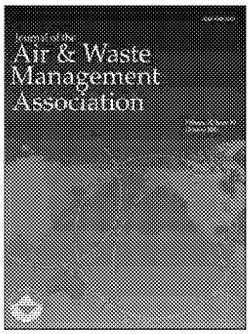

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Aerially guided leak detection and repair: A pilot field study for evaluating the potential of methane emission detection and cost-effectiveness

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Aerially guided leak detection and repair: A pilot field study for evaluating the potential of methane emission detection and cost-effectiveness

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ABSTRACT

Novel aerial methane (CH_4) detection technologies were used in this study to identify anomalously high-emitting oil and gas (O&G) facilities and to guide ground-based "leak detection and repair" (LDAR) teams. This approach has the potential to enable a rapid and effective inspection of O&G facilities under voluntary or regulatory LDAR programs to identify and mitigate anomalously large CH_4 emissions from a disproportionately small number of facilities. This is the first study of which the authors are aware to deploy, evaluate, and compare the CH_4 detection volumes and cost-effectiveness of aerially guided and purely ground-based LDAR techniques. Two aerial methods, the Kairos Aerospace infrared CH_4 column imaging and the Scientific Aviation in situ aircraft CH_4 mole fraction measurements, were tested during a 2-week period in the Fayetteville Shale region contemporaneously with conventional ground-based LDAR. We show that aerially guided LDAR can be at least as cost-effective as ground-based LDAR, but several variable parameters were identified that strongly affect cost-effectiveness and which require field research and improvements beyond this pilot study. These parameters include (i) CH_4 minimum dectectable limit of aerial technologies, (ii) emission rate size distributions of sources, (iii) remote distinction of fixable versus nonfixable CH_4 sources ("leaks" vs. CH_4 emissions occurring by design), and (iv) the fraction of fixable sources to total CH_4 emissions. Suggestions for future study design are provided.

Implications: Mitigation of methane leaks from existing oil and gas operations currently relies on on-site inspections of all applicable facilities at a prescribed frequency. This approach is labor- and cost-intensive, especially because a majority of oil and gas–related methane emissions originate from a disproportionately small number of facilities and components. We show for the first time in real-world conditions how aerial methane measurements can identify anomalously high-emitting facilities to enable a rapid, focused, and directed ground inspection of these facilities. The aerially guided approach can be more cost-effective than current practices, especially when implementing the aircraft deployment improvements discussed here.

PAPER HISTORY
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Introduction

Natural gas (NG) production in the United States has increased by 46% over the last decade (Energy Information Administration [EIA] 2017a), and the Energy Information Agency (EIA 2017b) projects that the United States will become a net exporter of NG in 2017. According to the EIA, NG has also played a significant role along with renewable energy sources in reducing power sector carbon dioxide (CO_2) emissions by displacing more carbon-intensive fossil fuels (EIA 2017b). However, leakage of NG—and its primary component methane (CH_4)—from the wellhead to the burner tip may erode the climatic and other environmental benefits of NG. In the recent past, the United States has targeted (U.S. Environmental Protection Agency [EPA] 2016a) reductions in fugitive CH_4 emissions throughout the NG supply chain as a way to cut national greenhouse gas emissions. Although fugitive CH_4 emissions from NG

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Color versions of one or more of the figures in the paper can be found online at www.tandfonline.com/uawm.
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are a global phenomenon (Saunois et al. 2016; Schwietzke et al. 2016), most of the published measurement studies specific to the NG industry took place in the United States. Nevertheless, country-specific analyses and measurements in other world regions have highlighted the need for a better understanding of NG-related CH_4 emissions outside the United States (Anifowose and Odubela 2015; Papailias and Mavroidis 2018), and some more detailed measurement results have been published recently (Johnson et al. 2017; Yacovitch et al. 2018).

Natural gas "leak detection and repair" (LDAR) programs—either through regulation (EPA 2016b) or voluntarily (George 2018)—aim at identifying and reducing CH_4 and other fugitive hydrocarbon emissions from equipment leaks at oil and gas (O&G) facilities. These LDAR programs are primarily ground based, i.e., the operator conducts LDAR activities at a subset of facilities at a set frequency (ranging from monthly to annually) employing specific instruments such as optical gas imaging (OGI) cameras.

Current federal LDAR regulations rely on on-site inspections of all applicable facilities at a prescribed frequency. A potentially improved approach is to draw on the strengths of aerial CH_4 measurements (i.e., high spatial coverage in a relatively short period allowing the amortization of operating costs over many facilities) to guide ground-based LDAR teams (i.e., optimize inspection and repair of facilities identified as potentially CH_4 high-emitting facilities by aerial measurements) instead of conducting periodic on-site inspections at all applicable facilities in random order. The goal is to enable a rapid, focused, and directed ground inspection of predetermined anomalously high-emitting facilities that contribute to substantial amounts of the total area CH_4 emissions. This is important because several studies, e.g., Allen et al. 2015; Brandt, Heath, and Cooley 2016; Lamb et al. 2015; Mitchell et al. 2015, have shown that total O&G CH_4 emissions originate from a disproportionately small number of facilities and components, e.g., 5% of leaks typically contribute over 50% of the total emissions (Brandt, Heath, and Cooley 2016). Therefore, periodic inspection of all applicable facilities as required by EPA's current regulation may be a less effective approach for detection and mitigation of emissions than focusing on just high emitters.

Capabilities to aerially detect CH_4 emission plumes from individual O&G facilities have previously been demonstrated using in situ (Conley et al. 2017) and remote sensing (Frankenberg et al. 2016; Thorpe et al. 2017) instruments. However, the performance of aerially guided LDAR has so far been assessed only in computer simulations. Kemp, Ravikumar, and Brandt (2016) simulated CH_4 leaks in a virtual NG production basin as well as their detection by automated infrared drones and three different ground-based LDAR technologies. They estimate a positive net present value (i.e., the value of saved NG exceeds program cost) for the automated infrared drones of about $8000/well, which is about one third greater than that of the highest ranked ground-based LDAR technology.

We analyze empirical data comparing aerial and ground-based LDAR approaches in terms of CH_4 emission mitigation potential and program cost-effectiveness. To the best of our knowledge, this study is the first to deploy and evaluate two existing distinct aerial CH_4 detection techniques to perform field measurements in a NG basin under normal operating conditions. The aerial techniques include Kairos Aerospace ("Kairos") infrared CH_4 emission plume imaging during overflights and Scientific Aviation (SA) in situ aircraft CH_4 mole fraction measurements near individual facilities (Conley et al. 2017). Throughout a 2-week period in parts of the Fayetteville Shale region, ground-based LDAR teams and both aerial teams conducted contemporaneous observations. Ground-based teams employed current regulatory protocols to conduct LDAR at random facilities independent of the aircraft and quantified CH_4 emissions from observed leaks at these facilities as detailed below. In addition, a separate ground-based team was exclusively dedicated to verifying the aerial observations for some of the sites (see Materials and Methods and Results). This study also provides insights into the real-world implementation challenges and requirements to coordinate aerial and ground-based LDAR platforms as a means to improve existing ground-based LDAR.

Materials and methods

Study area

The Fayetteville Shale in northern central Arkansas (Figure 1) was chosen as the study area for two reasons: First, two NG operators alone (Southwestern Energy Company, "SWN"; and XTO Energy Inc., "XTO") account for 76% of all active well pads (Arkansas Oil and Gas Commission 2016). The participation of SWN and XTO in this study enabled deployment of ground LDAR teams with on-site access at most NG facilities in the study area, thereby maximizing facility sample size while minimizing coordination efforts with operators. Second, both NG operators had participated in a previous study (Schwietzke et al. 2017) with part of this science team in the same study area, which simplified

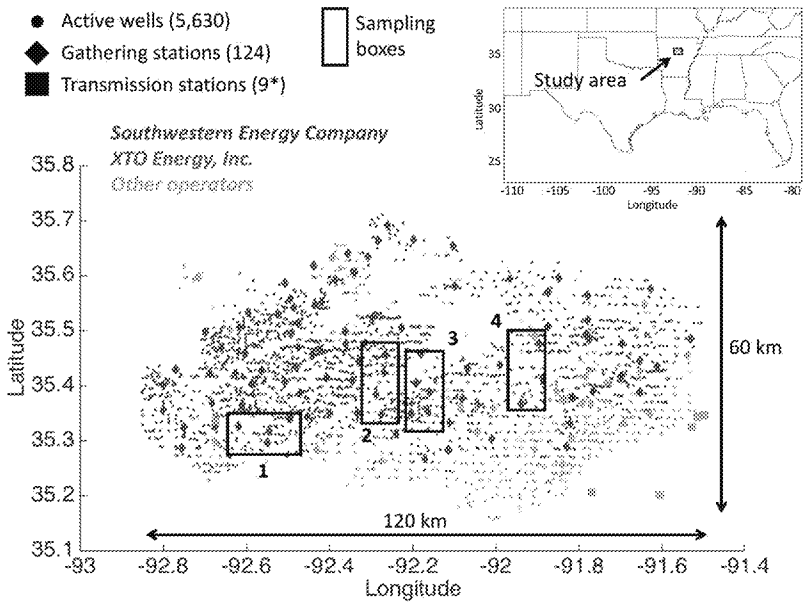

Figure 1. Fayetteville Shale study area location and sampling boxes. Two of the nine transmission stations are situated immediately outside of the plotted area and are thus not shown. No transmission station is located in any of the sampling boxes.

study design development, study logistics, and coordination between NG operators, ground teams, and aerial teams.

The NG infrastructure in the Fayetteville Shale area includes NG-producing well pads, gathering and boosting (G&B) compressor stations, transmission compressor stations, and gathering and transmission lines. The Fayetteville Shale is a dry gas region, i.e., no oil or hydrocarbon liquids are produced and no centralized gas processing facilities exist. Gas production–normalized CH_4 emission rates tend to be lower in dry versus wet gas regions (supplemental information [SI] Section 1), potentially due to the lack of some infrastructure with otherwise substantial CH_4 emissions, such as hydrocarbon liquid storage tanks (Lyon et al. 2016). The LDAR effectiveness demonstrated in this study is therefore specific to the Fayetteville Shale and may differ in wet gas areas due to additional potential CH_4 sources such as liquid hydrocarbon storage tanks. Four subregions ("sampling boxes" of 50 square miles or 128 km^2 each; Figure 1) were selected with the goal to sample representative facilities throughout the region (SI Section 1).

Measurement platforms and sampling approaches

Ground LDAR platforms

The ground teams used OGI cameras (FLIR GF320 [Nashua, NH, USA] and OpGal EyeCGas [Karmiel, Israel]) for on-site NG leak detection. An entire facility was scanned by a team member using the handheld camera based on a protocol similar to EPA's New Source Performance Standards OOOOa guidelines (EPA 2016c). Meteorological conditions on all days were consistent with these guidelines. In this approach, the maximum viewing distance (ranging between 4.8 and 19.8 m in this study) was determined with a small controlled release from a gas cylinder or gas release point at the well pad at the start of each measurement day, and then all equipment was viewed from that distance or closer. The gas contained 100% CH_4 and was released at a rate ranging between 17 and 200 g/hr (0.5–6 L/min). Trained, experienced camera operators conducted the ground LDAR. The camera operator traversed the operating facility, i.e., passing all accessible equipment sides, searching for emissions. Some elevated vent stacks had to be viewed from ground level pointing up, but most equipment, including produced water tank tops and vents, could be viewed from 1–2 m distance or closer. Any observed emission plumes were noted and logged. SI Section 2 describes the emission quantification procedure using the Bacharach Hi-Flow sampler. The developer of the Hi-Flow sampler raised concerned that this instrument may underestimate emission rates under several specific conditions: "(1) Calibration is more than ~2 weeks old; (2) firmware is out of date; or (3) the composition of the NG source is less than ~91% CH_4" (Howard, Ferrara, and Townsend-Small 2015). Note, however, that the Hi-Flow samplers were calibrated daily in this study, and that the average CH_4 content in the Fayetteville Shale is 96.5 mol-% (91.6 wt-%)

(Schwietzke et al. 2017). Also, the EPA recently concluded that there are no "data that indicate the Hi Flow Sampler malfunctions in high methane content gas streams" (EPA Office of Inspector General 2018). Underestimation of emission rates with the Hi-Flow sampler in this study is therefore unlikely.

Similar to regulatory or voluntary LDAR, ground teams were not charged with identifying or quantifying CH_4 emissions from compressor stacks (mostly at G&B stations), whereas aerially platforms usually detect CH_4 emission plumes from this specific source category.

Kairos LeakSurveyor leak detection platform

The Kairos LeakSurveyor is a two-channel instrument, which was installed in a light aircraft. The following technology short description is accompanied by additional details in SI Section 2. The first measurement channel is an infrared imaging spectrometer to detect "excess" CH_4 (above background) in the air below the aircraft. The second channel is an optical red/green/blue (RGB) imager to create an optical surface map of the surveyed region. An embedded global positioning system provides the geolocation of the spectra and images. A region is surveyed using a raster flight pattern (Figure 2a and SI Figure 1) where each pass covers a distance of ~400 m on each side of the plane given a surveying altitude of ~900 m above ground level (AGL). A single sampling box was surveyed more than once on the same day depending on time availability. The collected data from each survey were processed after landing to determine potential CH_4 plume detects. The analysis involves automated signal processing and human review of potential CH_4 plume detections for further refinement. Kairos' signal processing algorithms measure the absorption level at specific wavelengths relative to the absorption from atmospheric CH_4 background to indicate the significance of the detection for each pixel of approximately 4.5 m × 4.5 m area. The CH_4 absorption lines are measured in regions where there is no interference from absorption lines for other common hydrocarbons, such as ethane or propane. A matched filter approach is used to detect changes across all of the selected absorption lines. The goal is to match the pattern expected from CH_4 rather than better matching the pattern that would be expected from other gases that have some overlapping absorption lines in that portion of the spectrum. Environmental factors affecting LeakSurveyor's sensitivity to CH_4 plume detection include wind speeds (high winds lead to more dilution of emission signals) and illumination levels (e.g., clouds reduce illumination and surrounding water reduces reflectivity). These limitations (clouds in particular) were present during the study period and are described in more detail in SI Section 2. Note, however, that the plume detection statistics presented in this study—and which affect cost-effectiveness—account for these limitations.

As described in detail in SI Section 2, the resulting CH_4 plume detection maps (Figure 2b) are an exclusively quantitative product of automated signal processing. However, in postprocessing, Kairos analysts review these maps for factors that would increase or decrease the confidence that CH_4 emissions originate from the facility rather than a false-positive reading caused by noise or instrument bias. These factors include plume shape, proximity to an identifiable CH_4 source, illumination level, and alignment with known causes of false readings (such as lakes or rivers). These factors are accounted for in determining a "facility confidence level" ("firm," "likely," or "suspicious") for each detected facility. The reported facility plume confidence levels thus encompass some degree of subjectivity due to the human judgment involved and due to the determination of a semiqualitative metric (despite using quantitative and automated computation of the area-weighted confidence metric maps as a basis). In this study, however, the Kairos' CH_4 detections and LDAR cost-effectiveness were determined objectively by two external factors. First, our base case analysis (see below) only accounts for detected leaks when the ground LDAR teams confirmed an aerial detect. Thus, a Kairos "detect" with no ground LDAR confirmation is considered a false positive in our base case. This assumption of a false positive in the base case is intentionally conservative (i.e., potentially underestimating Kairos' CH_4 detections). An alternative scenario is described in Results, which explores the possibility of "missed" CH_4 sources by ground teams (e.g., due to short-duration episodic emission sources). Second, controlled CH_4 release experiments (SI Section 4) were carried out to objectively evaluate the effectiveness of the Kairos platform (as well as SA; see Materials and Methods). Note that Kairos did not quantify CH_4 emission rates in this study. Although CH_4 volumes within a plume could be estimated with an airborne infrared imaging spectrometer, their conversion to CH_4 emission rates would also require simultaneous near-ground wind speed measurements at each facility, which were not available in this study. Instead, we estimated lower bound and central estimate emission rates for each detected facility by Kairos using the controlled release tests and same-day quantified emission rates by SA for the same facilities (SI Section 4). Kairos' CH_4 detections (detected plume vs. no plume) are, however, completely independent of the SA approach.

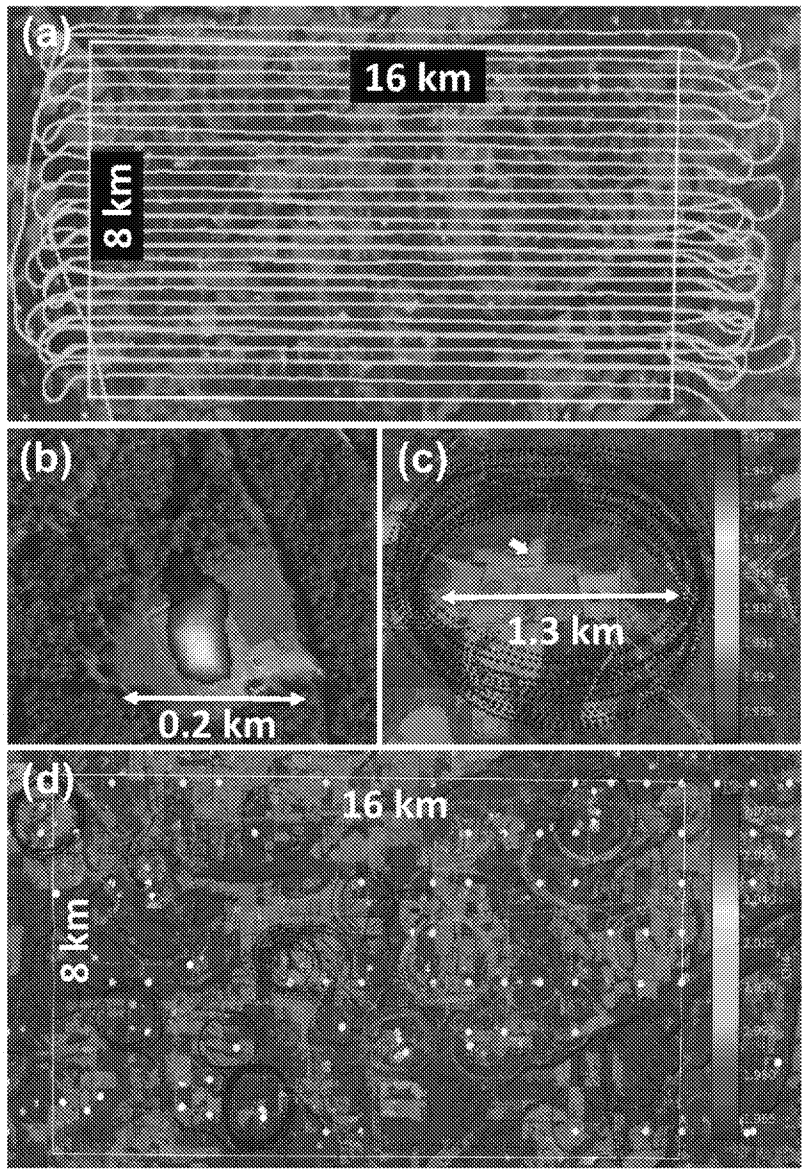

Figure 2. (a and b) Examples of Kairos flight patterns to illustrate both aerial leak detection methods. (c and d) Examples of Scientific Aviation flight patterns to illustrate both aerial leak detection methods. The white rectangles in panels (a) and (d) define sampling box 1. The yellow and white symbols in panel (d) indicate SWN/XTO and non-study partner O&G facilities, respectively. The SA flight patterns are color-coded by in situ measured CH_4 mole fraction (in ppm). Panel (b) shows a Kairos CH_4 plume detection image directly above an O&G facility. Panel (c) illustrates SA's emission quantification method for an O&G facility where the white arrow indicates the wind direction directly above the facility, and relatively clean air upwind and enhanced CH_4 mole fractions downwind of the facility, respectively. Note the scale differences between panels (b) and (c) for improved visibility of image details.

Scientific Aviation in situ leak detection and emission quantification platform

The SA leak detection approach involves in situ measurements of CH_4 dry air mole fractions (and optionally other gases) sampled downwind of potential emission sources. In this study, a Picarro 2301f cavity ring down spectrometer (Crosson 2008) was used in the SA aircraft. Detection of excess CH_4 occurs in real time, e.g., while passing an O&G facility at ~150 m AGL. Specific emission locations are verified through a circular flight path around the detected facility to rule out potential upwind plumes passing over this facility (Figure 2d). Although being an optional capability, emissions from a facility were quantified based on Conley et al. (2017), which is briefly summarized below (and expanded in SI Section 2). In situ atmospheric CH_4 mole fraction measurements (1.4 ppb measurement uncertainty; Karion et al. 2015) are performed along a closed cylindrical flight path (approximately 0.5–1.0 km diameter) at multiple altitude levels

(usually 60–600 m AGL) around an emission source (Figure 2c). The lowest and highest altitude levels are generally determined by topography, emission strength, and atmospheric conditions, respectively. The lowest altitude level of 60 m AGL is important for accounting for potential nearby upwind CH_4 sources and for enabling downwind CH_4 measurements as close to the surface as possible. Boundary layer vertical atmospheric mixing (usually occurring during the day when skies are not overcast) and horizontally consistent winds within the flight circle are needed to satisfy the quantification method's assumption of constant net emissions and winds within the circle. As described in SI Section 2, the aircraft propeller and engine exhaust have negligable impacts on emission plume mixing and contamination, respectively.

Coordinated air sampling and comparative analysis of LDAR cost-effectiveness

The main objective of all air sampling techniques deployed in the same area for the same amount of time was to locate high emitters and determine their cumulative CH_4 emission rates. Aerial and ground-based surveys were divided into Phase 1 (April 3–8, 2017) and Phase 2 (April 19, 2017), as shown in Figure 3. During Phase 1, aerial and ground-based air sampling were coordinated spatiotemporally as described below to maximize the probability that each sampling platform measured the same emission sources on the same day, thereby allowing a fair comparison of each platform. However, since each sampling platform is unique in terms of survey pattern and speed, simultaneous sampling at each facility was not possible. The Phase 1 surveys targeted as many facilities per box as possible for each platform and were used to determine LDAR cost-effectiveness. In Phase 2, facilities detected during Phase 1 (by ground and aerial teams) were revisited by ground and aerial teams to check for persistent leaks and to increase aerial detection sample size for evaluation of the Kairos platform using SA measurements at the same facilities. Ground teams did not quantify emission rates during Phase 2.

Air sampling for aerial and ground-based LDAR

Kairos and SA aircraft performed surveys of all SWN and XTO well pads and G&B stations in one 50 square mile (128 km^2) sampling box per day. Both aircraft sampled the same box on the same day (between 9:30 a.m. and 4:00 p.m. local time) except on two days when one of the aircraft remained on the ground (Kairos did not fly on April 8, 2017, because data collection was completed for all boxes; SA did not fly on April 5, 2017, because of poor atmospheric conditions; see SI Section 4). The aerial survey order of facilities in each box was randomized by applying a raster pattern (Kairos) and selecting the order of circled facilities based on the shortest total transit time between facilities (SA).

Four ground teams were deployed simultaneously with the aerial teams in the same sampling boxes each day during Phase 1. Three of these ground teams performed conventional LDAR at randomly selected facilities (i.e., independent of any aerial team detects) and quantified emissions when the ground survey indicated a leak (and when it was safe to do so). Although leak quantification is not always part of conventional LDAR activities, it was included here to determine the basis of LDAR cost-effectiveness.

Given that SA's platform indicated near-real-time detections, the objective of the fourth ground team during Phase 1 (SWN quick response team) was to

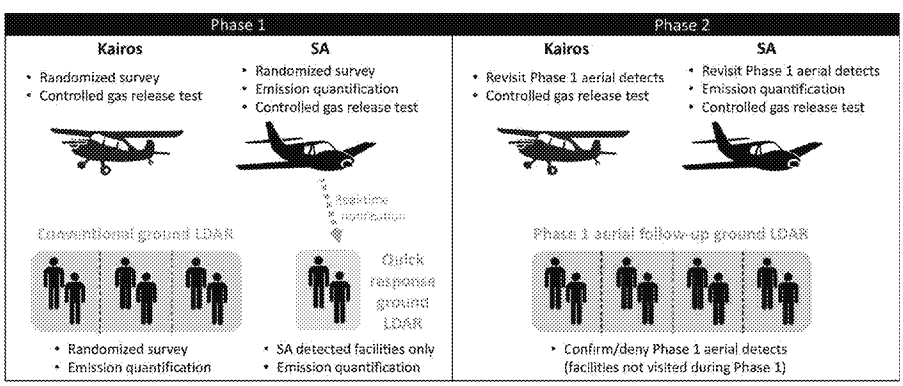

Figure 3. Study objectives of all ground and aerial teams during both study phases. Study design included surveying the same sampling boxes on the same day. During Phase 2, revisiting Phase 1 aerial detects by all teams also increased the sample size of identical facilities surveyed by both aerial and ground teams. A separate ground team (not shown) operated the metered (controlled) release of produced gas from a well pad.

perform LDAR and leak quantification at those SWN facilities that SA reported as a detect (via text messaging). This effort was aimed at getting as close to concurrent ground-based verification and quantification for more aerial detects than could be expected from relying on undirected inspections of the first three ground teams alone. The SWN quick response team transited to a reported SWN facility as soon as practical.

Controlled CH_4 release tests

Controlled releases of produced NG (i.e., multiple known CH_4 emission rates) were performed on two days (April 4 and 19, 2017; SI Section 4) at a single location to determine the approximate CH_4 "minimum detectable limit" (MDL) for the Kairos platform for the particular topography and atmospheric conditions being tested. Since the Kairos platform did not quantify emission rates, the controlled release experiment was also used to assign emission rates to each of Kairos' detected facilities (SI Section 2). Here, we use the term MDL to refer to the lowest expected emission rate for any detect. MDL thus defines the lowest magnitude of emission sources that can be detected, whereas the reliability of detection determines how consistently emission sources larger or equal to the CH_4 MDL will be detected (SI Section 4). This difference is important because MDL is used in this study for converting Kairos' CH_4 detects (binary) into detected CH_4 emission rates (as inputs for the cost-effectiveness calculation; SI Sections 2 and 4). Using MDL (as opposed to "detection threshold") ensures that Kairos' lower bound detected CH_4 emission rates are not overestimated.

SA also participated in a portion of the controlled release experiment to compare results with previous controlled gas release experiments (Conley et al. 2017), particularly in terms of accuracy and uncertainty of the estimated emission rates.

Analysis of air sampling data

This analysis distinguishes between fixable (or repairable) and nonfixable emission sources. Fixable emissions are defined as unintended emissions due to wear and tear on sealed surfaces such as emissions from gaskets, screwed connectors, valve packings, pressure relief valve seats, as well as open-ended lines associated with pipelines, pressurized vessels, and compressors. Fixable emissions may also include malfunctioning NG-powered pneumatic controllers, leaking storage tank gauge hatches, and leaking pressure relief valves. Although these pneumatic and tank sources are not always considered fugitive equipment leaks, these are often included in voluntary LDAR programs. Internal combustion engine (ICE) exhaust CH_4 slip from compressor stations is a vented emission source (by design) that is not generally considered fixable and which exists at each operating compressor station. Also, "planned or known" episodic emission events such as liquids unloadings are not generally considered fixable emission sources.

In a routine LDAR program for voluntary or regulatory purposes, aerially detecting the nonfixable emissions would not lead to leak repair and associated emission reductions. Our base case LDAR cost-effectiveness thus only considers fixable emissions. As described in detail below, the fixable fractions of aerially detected emissions were determined based on leak rate size distributions from the ground team measurements.

Determination of LDAR deployment cost and cost-effectiveness

The LDAR cost-effectiveness of each platform was determined based on the cumulative detected CH_4 emission rates and deployment cost as follows. Total Phase 1 costs, C_{Ground} and C_{Aerial}, for ground and aerial teams, respectively, were calculated using eqs 1 and 2:

$$C_{Ground} = F_{Ground} + (t_R \times N_R) \times H_{Ground} \quad (1)$$

$$C_{Aerial} = F_{Aerial} + (t_R \times N_R + t_{CF} \times N_{CF}) \times H_{Ground} \quad (2)$$

where F_{Ground} represents the deployment costs for the ground teams. F_{Ground} accounts for the deployed conventional ground LDAR teams consisting of one person per team for OGI-based leak detection and one person each for leak quantification using the Hi-Flow instrument. Each team was deployed for 4 days for 9 hr per day (i.e., the time each team spent during Phase 1 performing leak detection, quantification, and transit between facilities) at an hourly rate of US$142.06/hr based on ICF analysis (ICF International 2016), which accounts for labor and capital costs such as OGI cameras. Three conventional ground LDAR teams were deployed in this study, but this count only influences the number of facilities visited, not the cost-effectiveness. That is, additional teams would be able to visit more facilities, but also detect more leaks, thus equally adding to both the numerator and the denominator in the cost-effectiveness calculation.

One hour of leak repair time, t_R, at the same hourly rate H_{Ground} (US$142.06/hr) is added for each facility where a leak needed to be repaired, N_R, that would normally be spent in a real-world LDAR program. Note that the 1 hr repair time used here is similar to the average repair time in the EPA OOOOa LDAR cost

calculations of 1.13 hr per facility for both well sites and compressor stations (EPA 2016b).

Aerial LDAR costs include the aerial team costs (provided by SA and Kairos) and the ground LDAR leak confirmation costs for those facilities that were aerially detected and then visited by ground teams. F_{Aerial} is the total cost that the aerial teams charged to the project for the four flight days during Phase 1 ($60,000 for Kairos and $40,000 for SA). These costs account for downtime of aerial crews, e.g., during unsuitable weather conditions. The costs reflect that both aerial teams carried out their field measurements (including the supply and calibration of measurement instruments) without the help from the National Oceanic and Atmospheric Administration (NOAA) or other project-funded entities (and without the associated costs). The ground team hourly rate was applied to each detected facility where a ground team confirmed an aerially detected facility, N_{CF}, and, when a leak is confirmed, also for repair, N_R. The ground team follow-up time needed for leak confirmation, t_{CF}, was assumed to be 1.92 hr per facility (including an average 40 min trip to each facility, 15 min OGI camera leak verification, 30 min general facility survey, and 30 min leak documentation). The ground team follow-up time needed for leak repair, t_R, was assumed to be 1 hr per facility (same as for conventional ground LDAR). The durations for leak confirmation and repair used here are specific to this study and can be different elsewhere. For example, longer (or shorter) trip times between facilities (depending on well density in a given basin) would increase (or decrease) leak confirmation time. In terms of cost comparison among LDAR platforms (objective of this particular study), changes in modeled (or empirically derived) repair time would apply to all platforms. The contribution of leak confirmation and repair costs to total costs is summarized in SI Table 4.

For aerial and ground teams, cost-effectiveness, CE, (in US$ spent per million standard cubic feet [Mscf] CH_4 emissions avoided) was calculated according to eq 3:

$$CE = C \div (\Sigma ER_{Fixable} \times t_{Leak}) \quad (3)$$

where C is the total aerial or ground-based LDAR cost from eqs 1 and 2, Σ $ER_{Fixable}$ is the sum of the emission rates (in Mscf CH_4/hr) of each detected leak that was considered fixable/avoidable, and t_{Leak} is the amount of time (2190 hr, i.e., a quarter year, assuming semiannual inspections) that each leak would continue to emit CH_4 without the LDAR program (i.e., avoided emissions).

Results

The estimated cumulative CH_4 emission rate and cost-effectiveness of aerially guided LDAR depends on the CH_4 MDL, the reliability of detection of each aerial platform, the quantification accuracy, and the validity of assuming constant emission rates. Although the CH_4 MDL defines the lowest magnitude of emission sources that can be detected, the reliability of detection determines how consistently emission sources larger or equal to the CH_4 MDL will be detected.

SA's approach has been described recently (Conley et al. 2017), including its MDL of 5 kg CH_4/hr (0.26 Mscf CH_4/hr) and its CH_4 emission rate quantification accuracy ranging from 1% to 24% during different controlled gas release field experiments. In terms of reliability, all of SA's documented controlled gas release tests in this study (SI Section 4) and previous experiments (Conley et al. 2017) have been detected by SA. It should be noted, however, that the presence of upwind CH_4 sources with emissions larger than the targeted source can prevent a reliable emission quantification of the target. As described in Materials and Methods and in SI Section 2, topography, emission strength, and atmospheric conditions determine the lowest and highest sampling altitudes (and thus indirectly also the number of laps per facility). In this study, the average minimum altitude (to account for potential nearby upwind CH_4 sources and to extrapolate as close to the surface as possible) was 87 m AGL. The average number of laps per facility in this study was 14, i.e., close to the 15 laps that were previously determined to provide a stable emission rate estimate based on a "large eddy simulation" study (Conley et al. 2017).

The CH_4 MDL and detection reliability of the Kairos approach, which has not yet been evaluated in the peer-reviewed literature, was assessed in this study using two approaches. The experimental procedures and detailed results are described in SI Section 4 and are briefly summarized here. First, controlled NG release experiments were carried out to directly determine the CH_4 MDL. Second, SA's and Kairos' CH_4 detections during the aerially guided LDAR experiment were compared in the same sampling boxes on the same days. Based on six controlled NG releases ranging between 9 and 92 kg CH_4/hr (0.5–4.8 Mscf CH_4/hr), we determined Kairos' MDL to be 46 kg CH4/hr (2.4 Mscf CH_4/hr). As described in "Quantified CH_4 emission rates" below, Kairos' MDL is too high to detect CH_4 emissions from the majority of facilities. But it may nevertheless detect a substantial fraction of cumulative CH_4 emissions given the existence of high-emitting facilities, which is the rationale of aerially guided LDAR.

Considering controlled NG releases and the comparison of Kairos' CH_4 detection of O&G facilities with SA shows that Kairos was able to detect emissions above its CH_4 MDL during 12–29% of all passes in this study. Note that these test results are specific to the illumination and atmospheric conditions encountered during this field study. When considering only the "usable" passes (i.e., excluding insufficient illumination and atmospheric conditions), Kairos is able to detect emissions above its CH_4 MDL during 15–67% of the time.

For comparison, a Jet Propulsion Laboratory (JPL; National Aeronautics and Space Administration) research instrument, the infrared imaging spectrometer AVIRIS-NG, which has previously been deployed (Frankenberg et al. 2016; Thorpe et al. 2017) to detect CH_4 plumes from operating U.S. O&G facilities, participated in a 7-day controlled NG release experiment in 2013 (Thorpe et al. 2016). Based on a total of 143 gas releases, the AVIRIS-NG instrument detected 2.3 kg CH_4/hr (0.12 Mscf CH_4/hr) 30% of the time, 5 kg CH_4/hr (0.26 Mscf CH_4/hr) 73% of the time, and ≥22 kg CH_4/hr (1.2 Mscf CH_4/hr) 100% of the time. Note, however, that any MDL comparison with other instruments in previous studies is subject to limitations. First, the demonstrated MDLs in this study and in Thorpe et al. (2016) are subject to the respective weather conditions. For infrared imaging spectrometers, this largely refers to lighting levels (signal-to-noise ratio deteriorates with lower illumination) and wind speeds near the ground (measured path concentration of methane is proportional to emission rate divided by wind speed). Second, the relatively small and inexpensive instruments used in this study can be mounted on light aircraft (and scaled up in numbers) for commercial deployment, whereas AVIRIS-NG is a scientific instrument designed for research studies rather than commercial deployment.

Detected facilities during Phase 1

A summary of the number of sampled facilities and aerial and ground-based emission detects is shown in Table 1. A total of 257 NG facilities operated by SWN or XTO were located in sampling boxes 1–4, of which 49 facilities (19%) had leaks observed by the ground teams during Phase 1 compared with 24 detected facilities by SA (9%) and 7 facilities by Kairos (3%). The 49 ground-based detected facilities include 25 out of the combined 31 aerially detected facilities, thus providing a direct comparison of ground-based and aerial detects at 81% of the aerially detected facilities. Nevertheless, only 7 out of these 25 facilities provide leak detection comparisons from the same day. This temporal difference between aerial and ground-based emission detects is due to three of the four ground teams conducting conventional LDAR independent of the aerial teams, and Kairos detects being reported only after the end of Phase 1 (see above). Thus, whenever ground-based LDAR results differed substantially from aerial detects (emission magnitude by SA or detect vs. no detect by Kairos), the possibility of episodic emissions and leaks had to be taken into account as described in the following section. Other potential explanations such as aerial false positives and plumes missed by ground teams are also described in the following section (see "Fixable emission scenarios"). Note that ground teams were not charged with identifying or quantifying CH_4 emissions from compressor engine exhaust stacks (mostly at G&B stations), whereas aerial detects may include signals from this source. However, ground measurements included compressor seals and most of the time also engine crankcases. The latter is a negligible CH_4 emissions contributor, as it represents the same unburned CH_4 as in the exhaust stack, but at much lower flow volume. Considering the five days when Kairos and SA sampled the same boxes on the same day (including Phase 2), Kairos and SA detected CH_4 plumes at

Table 1. Summary of sampled facilities and aerial and ground-based emission detects during Phase 1. See also SI Figure 2 for a definition of the different types of ground verifications and (no) ground verifications.

	Well pads (N = 239)			G&B stations (N = 18)			Total (N = 257)
Parameter	Ground	SA	Kairos	Ground	SA	Kairos	SA + Kairos
No. of facilities surveyed	98	239	239	11	18	18	n/a
No. of detects in Phase 1	40	12	7	9	12	0	31
No. of ground verifications	n/a	9	6	n/a	10	0	25
Same day		2	0		5	0	7
After 2 days		0	2		1	0	3
In Phase 2		3	4		1	0	8
Before aerial detect		4	0		3	0	7
No. of no ground verifications		3	1		2	0	6
Known emission event		2	1		0	0	3
Study period ended		1	0		2	0	3

Notes. See also SI Figure 2 for a definition of the different types of ground verifications and (no) ground verifications. N = no. of facilities in all sampling boxes.

13 and 21 facilities, respectively. Three of these included identical facilities (see SI Table 3). Only one of these three facilities were visited by ground teams, which found six leaks (but this occurred during Phase 2 where no ground quantification took place).

Quantified CH_4 emission rates

Total detected CH_4 emissions

The Phase 1 "measured emissions" (Figure 4a) represent the cumulative CH_4 emission rates quantified by each platform during Phase 1 irrespective of whether these emissions were fixable or not. All error bars in Figure 4 represent 1σ uncertainties derived by summing the facility-level quantification uncertainties (see Materials and Methods, "Measurement platforms and sampling approaches") in quadrature. Kairos did not quantify emissions, and the Kairos emission rates were estimated as lower bound and central estimates. As described in more detail in SI Section 2, this was achieved through a combination of (i) applying SA's quantified emission rates at facilities that were detected

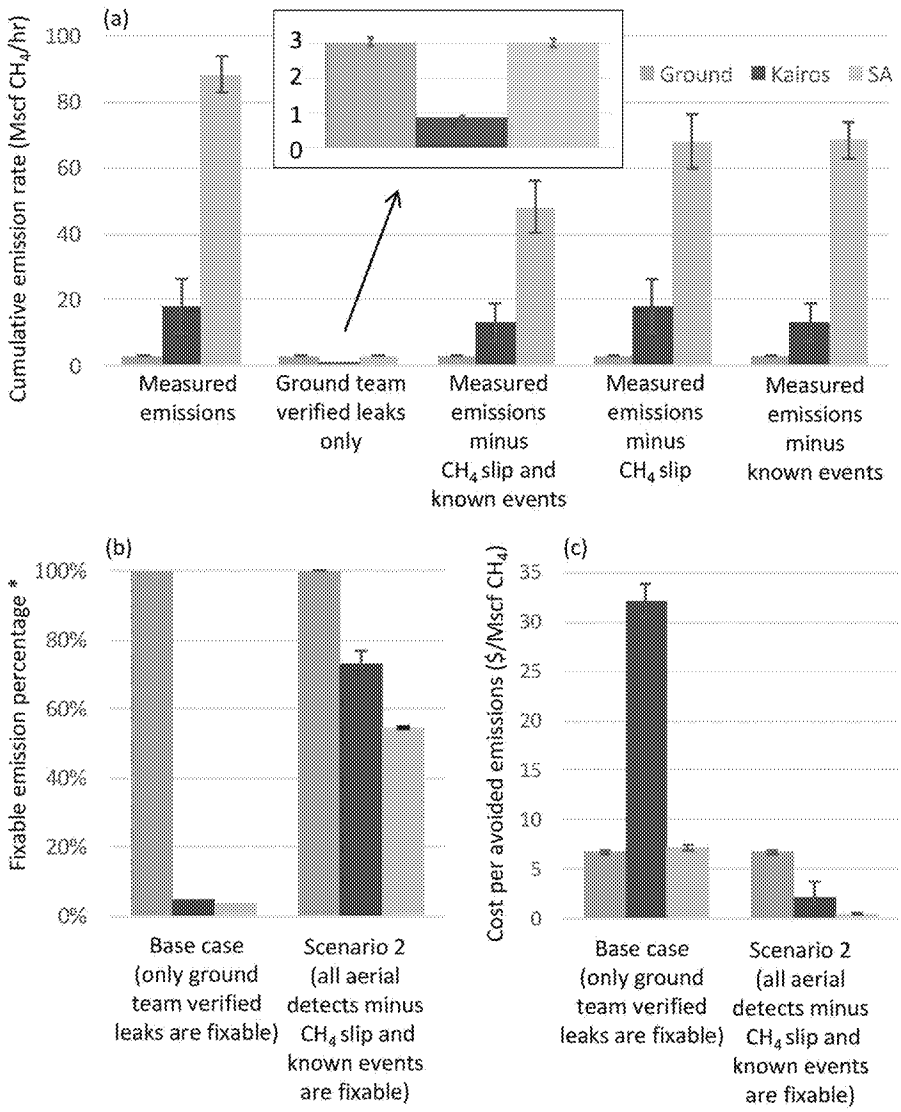

Figure 4. (a) Cumulative (all facilities) detected CH_4 emission rates as measured (leftmost cluster) and including only specific CH_4 sources, i.e., those leaks identified as fixable based on routine ground LDAR (remaining clusters for all five scenarios) during Phase 1. The inset magnifies "Ground team verified leaks only." Note that the ground team sample size (number of surveyed wells) is a factor of 2.4 smaller than the aerial teams (factor 1.6 smaller for G&B stations). (b) Two scenarios of fixable emission rates as a percentage of measured emission rates for each platform. (c) Cost-effectiveness comparison for both fixable emission rate scenarios. All error bars represent 1σ uncertainties derived by summing the facility-level quantification uncertainties (see Materials and Methods) in quadrature. The emission difference between scenario 2 and the base case is due to potential undetected/unmeasured fixable leaks by ground teams, potential aerial false-positive detects, or the presence of episodic emissions (preventing their detection by ground surveys due to differences in the timing between the aerial and ground-based surveys).

by both SA and Kairos and (ii) assigning results from the controlled NG release experiment (CH_4 MDL and reliability of detection) according to Kairos' reported facility confidence level for each detect. Central estimates rather than upper bounds were calculated because a "firm" detect can be associated with the demonstrated CH_4 MDL, but it does not rule out a substantially higher emission rate. Note that a "firm" detect signifies the highest probability category that a detect is not a false positive (see Materials and Methods, "Measurement platforms and sampling approaches"). The "firm" label is only applied if a plume is detected. The "firm" label is not used to predict CH_4 plume detection.

The wind conditions during the controlled NG release experiment on April 19, 2017, were comparable with those during Phase 1 (April 3–8, 2017). Surface wind speeds (which are most relevant for the Kairos approach) were compared at nearby airports (Russelville Municipal, Searcy Municipal, and Cantrell Field), which are located within <50 km of the study area. The average surface wind speeds were 4.9 m/sec during the controlled NG release experiment and 5.1 m/sec during the 9:30 a.m. to 4:30 p.m. (local time) flight windows on April 3–8, 2017. Wind speeds therefore do not introduce a substantial bias when using results from the controlled NG release experiment to determine Kairos' detected CH_4 emission rates during Phase 1.

The aerial teams detected substantially more total CH_4 emissions than the ground teams (factor of 3–26) despite a factor of 2 fewer detected facilities (Table 1). As described in detail in SI Figure 2, the difference between total aerially detected CH_4 emissions and those detected by the ground teams (see definition of fixable leaks above) is likely due to a combination of factors:

(i) Aerial detects include nonfixable emissions from G&B compressor exhaust CH_4 slip and known routine events such as liquids unloadings that were not measured by the ground teams. Also, akin to regulatory and voluntary LDAR programs, ground teams were not always able to quantify all emissions on-site because of safety concerns or due to difficulties in equipment access (e.g., lack of manlifts at each facility) at 10% of sites surveyed even though aerial teams may have detected these emission sources. Only 1 out of 111 surveyed facilities by ground teams included a reported CH_4 source that was not quantified due to safety concerns. The ground team reported open thief hatches on a water tank, but SA and Kairos did not detect a plume from this facility later the same day.
(ii) Differences in the timing between the aerial and ground-based surveys at specific facilities may have prevented ground verification of aerial detects in the presence of potential episodic emission sources. The temporal delay is partly because Kairos reported detects only after Phase 1; thus, not all Kairos detects were verified by ground teams, which did not survey all facilities due to limited personnel. Similarly, the single SWN quick response team was unable to follow up on all SA detects.
(iii) Potential false-positive aerial detects may have occurred.
(iv) Ground surveys using OGI scans may have failed to identify existing fixable leaks. Given the OGI's 3 orders of magnitude higher sensitivity of leak detection compared with the aerial platforms in this study (SI Sections 2 and 4), it is unlikely that an OGI camera would miss a major CH_4 plume when the OGI camera is directed at such a plume.

The "Ground team verified leaks only" cluster in Figure 4a considers only those emission sources that were indeed detected (and would then be fixed) by ground teams. The 3.0 Mscf CH_4/hr (58 kg CH_4/hr) cumulative emission rate by the ground teams in Figure 4a excludes 0.3 Mscf CH_4/hr (5.8 kg CH_4/hr) detected by the SWN quick response team because these leaks were not detected using conventional LDAR. See "Fixable emission scenarios" below for a description of the aerially detected leaks that were verified by ground teams.

The "Measured emissions minus CH_4 slip and known events" cluster in Figure 4a excludes estimated CH_4 emissions from G&B compressor exhaust CH_4 slip and known events from the "Measured emissions" cluster. CH_4 slip estimates are based on a recent study (Vaughn et al. 2017) in the same study area (Fayetteville Shale), which were calculated based on 111 recent measurements of representative G&B compressor engines and which were consistent with fence-line ground-based measurements and aircraft measurements (SI Section 7). The CH_4 emissions from known events were calculated as SA quantified emissions at facilities with known events minus the sum of ground-based quantified emissions at the same facilities (when available) and G&B compressor CH_4 slip (for G&B facilities only). Although uncertainties in all three parameters were propagated in this

calculation, it assumes zero aerial false positives and zero missed ground-based leak detects (note that these assumptions are relaxed in scenario 2 below).

The rightmost two clusters in Figure 4a show the contributions of CH_4 slip and known events individually. The results indicate that almost half of the emission rate difference between SA and ground teams is due to CH_4 slip and known events (about one third between Kairos and ground teams).

The remaining differences are likely attributed to the other three factors discussed above (i.e., temporal measurement delays between ground and aerial teams, potential false-positive aerial detects, and other emission sources missed or unmeasured by ground teams). The potential combination of these factors prevents a definitive quantification of the fixable emissions from the aerial detects. Here, we postulate two different fixable emission scenarios from the aerial detects (base case and scenario 2 described below) and use these to estimate a range of LDAR cost-effectiveness for each platform.

Fixable emission scenarios

Our base case assumes that the difference between aerially and ground-based cumulative detected CH_4 emission rates is entirely due to a combination of aerially detected nonfixable emissions and aerial false positives. Our base case thus considers only those emission sources fixable that were indeed detected and quantified (and could thus be fixed) by ground LDAR teams (Figure 4b, left cluster).

Whereas the base case cumulative fixable emission rate of the ground teams is equal to all ground measured leaks by definition, the base case cumulative fixable emission rate of the aerial teams can only be estimated because (i) not all aerially detected facilities were visited by ground LDAR teams and (ii) only some facilities were detected on the same day by both ground teams and aerial teams.

In this analysis, the cumulative fixable emission rate of the aerial platforms is a subset of the 3.0 Mscf CH_4/hr from the ground teams because the aerial teams detected fewer facilities (6 for Kairos and 22 for SA excluding known events) than the ground teams (49; Table 1). Since the aerial platforms cannot detect the smallest leaks due to the relatively high CH_4 MDLs (emission rate size distributions are discussed below), we assume that the aerial teams have detected only the largest fixable leaks that were indeed detected by the ground teams.

For example, SA detected 10 well pads (12 minus 2 well pads with a known event; Table 1). The 10 largest-emitting well pad leaks (based on ground team measurements) account for 79% of the cumulative emissions from all 40 quantified well pads because of the highly skewed emission distribution (Figure 5), similar to previous studies (Brandt, Heath, and Cooley 2016; Zavala-Araiza et al. 2017). Considering both well pads and G&B stations, SA's and Kairos' estimated fixable emissions are equal to 99.6% and 29.2% of all conventional ground LDAR team fixable emissions (3.0 Mscf CH_4/hr), respectively.

The fixable emission scenario 2 (Figure 4b, right cluster) provides an upper bound of fixable emissions by accounting for potentially unquantified fixable leaks during the ground surveys due to undetected/unmeasured leaks by ground teams and the presence of episodic emissions. Subtracting the nonfixable emissions

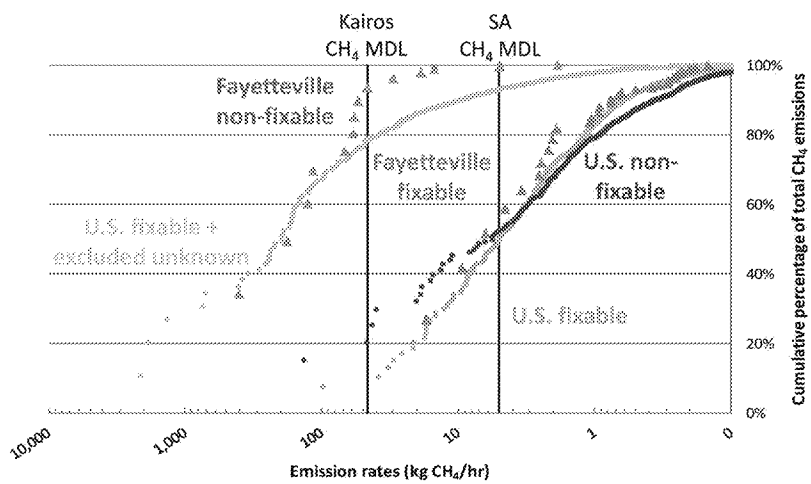

Figure 5. Comparison of emission rate distributions from fixable and nonfixable sources in this study (triangles) with previous studies (dots; based on a data set by Brandt, Heath, and Cooley [2016], which was further analyzed here) and with the aerial platform CH_4 minimum detectable limits (MDL; black vertical lines) demonstrated in this study.

due to CH_4 slip and known events from the aerial cumulative emission detects results in remaining fixable emission rates of 758–1062 kg CH_4/hr (SA; 40–56 Mscf CH_4/hr) and 152–360 kg CH_4/hr (Kairos; 8–19 Mscf CH_4/hr). These are the fixable emission rates that the ground teams were expected to detect if the ground teams had been able to measure simultaneously with the aerial teams (and considering that the known events CH_4 emission rates above are representative for all measured facilities). In this scenario, the cumulative aerial fixable emission rates are a factor of 13–19 (SA) and 3–6 (Kairos) larger compared with ground surveys. Note that this upper bound scenario assumes that all aerial emission estimates are correct (no aerial false positives, which are included in the base case). Nevertheless, both scenarios account for all aerial costs, including aerial surveys and ground-team follow-up in case of an aerial detect.

Quantified CH_4 emission rate distributions

Similar to previous studies (Brandt, Heath, and Cooley 2016; Zavala-Araiza et al. 2017), emission rate distributions in this study are highly skewed (Figure 5), such that leaks from the highest-emitting 7% of facilities contribute 52% of cumulative fixable emissions, and the highest-emitting 13% of facilities contribute to 49% of cumulative nonfixable emissions. Kairos' demonstrated CH_4 MDL (46 kg CH_4/hr or 2.4 Mscf CH_4/hr) is larger than the total fixable emission rate from any single facility quantified by ground teams during Phase 1. Kairos' identification of fixable leaks in the Fayetteville Shale thus depends on the presence of fixable leaks larger than those quantified by ground teams, or on the presence of co-located fixable and nonfixable emissions, the sum of which is above Kairos' CH_4 MDL (see triangles in Figure 5).

SA's demonstrated CH_4 MDL is sufficient to detect the four largest fixable emission sources (9% of all fixable leaks) during Phase 1 (considering the 10% ground-based quantification accuracy; SI Section 2), which account for 59% of all fixable emissions with leak rate sizes >4.5 kg CH_4/hr (>0.24 Mscf CH_4/hr).

Comparison with national-level CH_4 emission rate distributions

Next, we compared the demonstrated aerial CH_4 MDLs with CH_4 emission rate distributions elsewhere in the United States based on a measurement data set compiled by Brandt, Heath, and Cooley (2016). As described in SI Section 8, we categorized this data set into fixable and nonfixable emission sources from the O&G production sector only (i.e., excluding processing, transmission, distribution), and we excluded entries where the specific CH_4 source and/or the O&G sector could not be identified. This process resulted in 1887 fixable and 1229 nonfixable CH_4 sources, i.e., 2–3 orders of magnitude greater sample size than in this study. Note that all 3116 data points as well as the excluded data points represent physical measurements as opposed to emission factors.

We find that this study's fixable CH_4 emission rates are similar to those of Brandt, Heath, and Cooley (2016), but the latter study includes multiple substantially larger (up to an order of magnitude) fixable sources, potentially due to the greater sample size (leading to the identification of more high-emitting sources). The nonfixable CH_4 emission rates in the O&G production sector are over an order of magnitude larger in this study compared with Brandt et al. (Brandt, Heath, and Cooley 2016). This comparison is subject to two caveats. First, each CH_4 emission rate in this study represents the total of a facility, whereas the Brandt, Heath, and Cooley (2016) data set also includes individual components. Second, many Brandt, Heath, and Cooley (2016) data entries with unknown CH_4 source and/or O&G sector (N = 2460) have substantially larger CH_4 emission rates than those identified as fixable and nonfixable O&G production sources. The blue symbols in Figure 5 show the maximum possible fixable CH_4 emission rates in the Brandt, Heath, and Cooley (2016) data set assuming that all unknown source/sector entries are fixable. The true fixable CH_4 emission rate distribution of the Brandt, Heath, and Cooley (2016) data set is thus expected in the space between the blue and light green circles.

Considering this larger Brandt, Heath, and Cooley (2016) data set (and the caveats above), we find the following: SA's CH_4 MDL of 5 kg CH_4/hr (0.26 Mscf CH_4/hr) would be sufficient to detect O&G production sector emission sources outside the Fayetteville Shale that contribute 51–93% of fixable emissions (depending on how many of the "excluded unknown" CH_4 source emissions are fixable, as shown in Figure 5). The corresponding detectability for Kairos (considering a CH_4 MDL of 46 kg CH_4/hr or 2.4 Mscf CH_4/hr, which is specific to the illumination conditions during this study) is 10–78% of fixable emissions. These data represent wide ranges that prompt further research (see Discussion) and highlight the importance of MDL for detecting fixable emissions. Nevertheless, the results indicate the potential for aerially guided LDAR to detect a substantial fraction of total fixable CH_4 emissions. Keep in mind that no single O&G basin may actually represent the average U.S. data set, i.e., emission potentials in a given basin may be lower or higher than in the distributions shown in Figure 5.

LDAR cost-effectiveness

The cost-effectiveness of each LDAR approach is defined as the total cost expended in Phase 1 divided by the avoided CH_4 emissions due to the detection of fixable emissions in Phase 1 (see Materials and Methods). The detailed cost breakdowns by LDAR platform, facility type, and LDAR element (detection, quantification, confirmation, and repair) are provided in SI Section 5. Emission detection/quantification costs during Phase 1 are lowest for ground-based LDAR ($38,000) and SA ($40,000), with approximately 50% greater cost for Kairos ($60,000). The LDAR cost estimates for all aerial and ground teams include the costs for the individual portions of emission detection, quantification, and leak repair. Although emission quantification is not part of routine LDAR, it was performed in this study for comparing the different LDAR platforms. Sensitivity calculations for LDAR excluding emission quantifications, which lead to minor changes in results, are described in SI Section 6. The LDAR cost estimates in this study assume long-term routine costs to perform an annual routine LDAR program as described below.

Considering a conventional ground-based LDAR program with semiannual inspection frequency and a Gaussian leak frequency distribution, each fixable leak would on average continue to emit CH_4 for a quarter year (2190 hr, i.e., until LDAR is repeated at the same facility) without the LDAR program. Yet in actual operating conditions, company standard operating and maintenance practices (beyond LDAR) may detect some of these leaks, especially the high-emitting leaks. Although the LDAR frequency may vary among operators or regions, we assume the same frequency for both ground and aerial LDAR to allow a fair comparison between both LDAR types.

As shown in Figure 4c, the cost-effectiveness of ground-based LDAR (US$6.50–7.00 spent per Mscf CH_4 emissions avoided) is comparable to SA (US $6.95–7.50) in our base case, and both are substantially more cost-effective than Kairos (US$30.59–33.77). The factor of 4.5 difference between Kairos and the other two platforms is mostly due to Kairos' relative high CH_4 MDL resulting in six detected facilities for Kairos (excluding known events) compared with 22 for SA and 49 for ground teams, and partially due to cost differences. This shows that potential future improvements in the aerial LDAR technologies (i.e., a lower CH_4 MDL and enhanced detection reliability under varying illumination conditions for Kairos) could substantially improve aerial LDAR cost-effectiveness as defined here.

However, Kairos' and SA's cost-effectiveness outperform ground-based LDAR in scenario 2 by factors of 3 and 15, respectively, despite the differences in aerial MDL between Kairos and SA in this study. The aerial cost-effectiveness in this scenario is based on the assumption that future ground LDAR can be improved to detect and repair substantially more leaks than in this study (that were potentially undetected/unmeasured by ground teams due to missed or episodic leaks).

Note that the absolute cost-effectiveness values presented here were specifically derived to enable a comparison between ground-based and aerially guided LDAR. The cost parameters used here (SI Section 5) are consistent with some other major studies (EPA 2016b; ICF International 2016). However, differences in scope and analytical system boundaries (e.g., EPA's OOOOa analysis includes the cost of developing a monitoring plan, compliance notification, whereas the ICF study and this study do not include it) prevent a meaningful cross-study comparison. Harmonizing all analytical differences is beyond the scope of this paper.

All results presented in Figure 4 are specific to the Fayetteville Shale dry gas region, which does not include key fixable sources such as condensate tanks, which would likely constitute additional fixable emission sources for aerial surveys in other basins. A recent OGI helicopter survey (Lyon et al. 2016) and a ground-based fence-line measurement study (Brantley et al. 2014) (supported with OGI footage), both across the United States, suggest that tank emissions include both fixable leaks and venting, and that the observed emissions also have a highly skewed distribution. In fact, 20% of fixable sources in the Brandt, Heath, and Cooley (2016) data set are from different types of tanks (not all types are specified), which contribute 47% of cumulative fixable emissions.

Discussion

To the best of our knowledge, this is the first study to empirically compare the CH_4 emission mitigation potential and cost-effectiveness of ground-based and aerially guided LDAR in the O&G industry during normal operating conditions. Beyond comparing two specific aerial NG detection technologies in one NG basin, the objectives of this study were (i) to better understand the practical challenges of implementing aerially guided LDAR and (ii) to demonstrate how aerial NG detection technologies can be employed to direct and improve on existing ground-based LDAR. In contrast, previous studies (Conley et al. 2017; Frankenberg et al. 2016; Kemp, Ravikumar, and Brandt 2016; Thorpe et al. 2017) either focused on the measurement techniques or were computer simulations. Although the findings in this study account for

existing, commercially available aerial NG detection technologies, these technologies may evolve in the future. As illustrated here, the intention of using aerial NG detection technologies is not to replace current LDAR, but to make current LDAR more effective by providing ground teams with data to prioritize facilities with high CH_4 emission rates.

We show that aerially guided LDAR can detect sufficiently large leaks to mitigate about half or more of all fixable CH_4 emissions depending on the employed method's CH_4 MDL. Considering the uncertainties and limitations discussed earlier (including the stated system boundaries for comparing costs among LDAR platforms), aerially guided LDAR can be at least as cost-effective as ground-based LDAR alone, also depending on the employed method's CH_4 MDL. This study also points out important open questions and practical considerations for future developments and implementations of aerially guided LDAR or any remote sensing–based LDAR.

Our results show that fixable CH_4 emissions per O&G production facility determined from the aerial approach are up to an order of magnitude greater compared with ground-based detects. Further research needs to identify the potential reasons for this gap. This may include undetected/unmeasured leaks by ground teams, which followed regulatory LDAR procedures in this study. Our results show that these potentially missed CH_4 sources by ground teams (along with other plausible explanations such as episodic CH_4 sources and aerial false positives) largely contribute to the overall uncertainty, which is represented by the difference between our base case and scenario 2. In future study designs, ground teams may be charged with identifying, documenting, and quantifying (when possible) any other CH_4 sources that are not considered part of an LDAR protocol. Although this could increase the scope of fixable emission sources for routine ground-based LDAR, it may also reduce the uncertainty in the cost-effectiveness of aerially guided LDAR.

The Fayetteville Shale CH_4 emission rate size distributions in Figure 5 show that nonfixable CH_4 sources (e.g., G&B compressor exhaust CH_4 slip, liquids unloading, blowdowns) are also about an order of magnitude larger than fixable CH_4 sources. This suggests that the detection of facilities using aerial methods is often due to signals from expected nonfixable CH_4 sources (those occurring by design). The detected nonfixable CH_4 sources may originate from the same facilities with other fixable sources. As a result, a large aerial detect may or may not result in the ground confirmation of a large fixable leak. Vice versa, a relatively small aerial detect could be confirmed as a relatively large fixable leak. The ability to remotely distinguish between fixable and nonfixable CH_4 sources would constitute a substantial improvement of aerially guided LDAR. This may include better pinpointing specific CH_4 sources from the air or facility-based smart communication systems that automatically signal known nonfixable CH_4 releases from sources such as liquids uloadings, blowdowns, and activated pneumatic devices. This may improve cost-effectiveness only marginally (ground confirmation cost was only 3–11% of total aerial cost in this study; SI Table 4). However, it would allow ground teams to confirm and fix leaks more quickly considering the limited availability of ground teams and the potential importance of episodic leaks, both of which were major impediments for explaining the large differences between aerial and ground-based measurements.

In particular, G&B stations will mostly yield a detect by aerial teams because of compressor exhaust CH_4 slip, but since CH_4 slip is expected at all operating G&B stations, this is often not a relevant signal for fixable leaks. Thus, future aerially guided LDAR may focus on well pads and exclude G&B stations. Nevertheless, in cases where bottom-up inventories of specific G&B stations are available (with known engine counts and types and operating status), aerial surveys may identify anomalously high emitting G&B stations for further investigation by ground teams, e.g., to identify and fix potentially abnormal operating conditions.

Given the regional heterogeneity in leak size distributions shown in this study and elsewhere (Brandt, Heath, and Cooley 2016; Ravikumar and Brandt 2017), aerially guided LDAR will be more effective in some regions compared with others. In particular, the aerial technologies may detect more leaks in wet gas regions with substantial emissions from condensate tanks and other associated equipment. It is thus expected that the cost-effectiveness of aerially guided LDAR (relative to conventional ground-based LDAR only) would be better in wet gas regions compared with the dry Fayetteville shale region (or other dry gas regions in the United States or internationally). Also, regions with greater distances between facilities are more suitable for the aerial approach.

Through further research and development of the aerial CH_4 emission detection technology and the logistics to guide ground-based LDAR teams using aerial CH_4 detects, it may be possible for operators to locate the CH_4 high-emitting equipment leaks more cost-effectively than current techniques involving scheduled, ground-based LDAR inspections only. The following improvements in field study design based on the practical experiences from this pilot research project may improve the conclusiveness of future findings:

(i) Temporal variability has been identified as a critical factor in understanding O&G CH_4 emissions in recent studies (National Academies of Sciences Engineering and Medicine 2018; Schwietzke et al. 2017; Vaughn et al. in press), consistent with this paper. The wide spatial coverage of aerial measurements in a short amount of time (vs. ground measurements) increases the chances of detecting episodic leaks. Deploying more than one quick response ground LDAR team may lead to more prompt ground confirmation, more identification of episodic leaks, and thus a more mechanistic understanding of the underlying leak causes. If this is impossible due to lack of ground personnel, the conventional ground LDAR teams could be deployed prior to the aerial experiment without repairing leaks to avoid biasing the leak potential. This experimental design may reduce the fixable emission uncertainty arising from the potential influence of temporal variability of leaks.

(ii) Performing controlled NG release tests on multiple sampling days (ideally each sampling day) may calibrate the aerial technologies' CH_4 MDL to potentially daily varying weather conditions (e.g., illumination levels).

(iii) Aerial detection technologies with postflight facility reporting (such as Kairos) should be accompanied by real-time aerial detection technologies in the same sampling boxes on the same day as done in this study (albeit not on all days). This will help minimize the effects of temporal variability (see above) and will increase the sample size crucial for evaluating detection reliability.

(iv) When aerial detects could not be confirmed by ground teams, ground teams may inspect neighboring facilities given potential location errors of the aerial detect.

(v) The field campaign schedule should allow for off-days for both aerial and ground confirmation teams to allow for the same leeway in flight versus no-flight decisions as in real-world applications.

(vi) Target only well pads to obtain the cost-effectiveness estimates not determined in this study. This approach is advisable over removing G&B stations from cost-effectiveness calculations post campaign because both ground and aerial teams (at least the SA approach) would sample differently if the study design excludes G&B stations.

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Conflict of interest

The authors declare the following personal competing financial interests. Stephen Conley is the owner of Scientific Aviation Inc., which provided one of the aerial methane measurement technologies for comparison with current ground-based measurements in this study. Ken Branson is an employee of Kairos Aerospace, which provided one of the aerial methane measurement technologies for comparison with current ground-based measurements in this study. Research funding provided by institutions associated with the oil and gas industry is as described in the Acknowledgments and Fiji George, Doug Jordan, Changyong Zhang, and Heide L. Mairs are employees and stockholders of these institutions. Gilbert R. Jersey is a former employee and a stockholder and is now a consultant to institutions associated with the oil and gas industry. Matthew Harrison and Terri Lauderdale are employees and stockholders of AECOM, which offers various engineering services to the oil and gas industry.

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Message

From: Weitz, Melissa [Weitz.Melissa@epa.gov]
Sent: 12/6/2018 6:01:16 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
CC: DeFigueiredo, Mark [DeFigueiredo.Mark@epa.gov]; Eisele, Adam [Eisele.Adam@epa.gov]
Subject: FW: GSI's DOE Marginal Wells Study - Participation Request
Attachments: Regulatory Participation Request_GSI Marginal Wells Study with DOE_6Dec2018.docx

Hi Amy,

DOE has funded a project on marginal wells (which I think has been mentioned on one of our recent calls, though can't remember which).

NETL/DOE's website on the project (https://www.netl.doe.gov/node/5775) includes some text on NSPS that you may want to review, e.g.:

"In June 2016, the U.S. Environmental Protection Agency (EPA) published a final rule in the Code of Federal Regulations to amend the New Source Performance Standards at subpart OOOO, and finalize new standards at subpart OOOOa to reduce methane emissions from new and modified oil and gas facilities. The updated standards included requirements for marginal well sources—oil wells that produce less than 15 barrels per day or gas wells that produce less than 90,000 cubic feet per day—which were not previously addressed.

EPA's decision was based on limited data. The Agency had presumed emissions from marginal and non-marginal well sites were comparable, but that conclusion was derived from data amassed from studies employing a wide variety of technical approaches, none of which were designed to assess emissions specifically from representative populations of marginal well sites.

As part of an ongoing regulatory review and reconsideration process, on September 11, 2018, EPA issued proposed targeted improvements to the 2016 standards that aim to streamline implementation, reduce duplicative EPA and state requirements, and decrease unnecessary burdens on domestic energy producers. The Agency continues to review other aspects of the 2016 rule that could be the subject of future rulemaking.

While the costs of regulatory compliance impact all producers, small independent oil and gas producers who operate many of the over 700,000 marginal wells that dot the United States could be disproportionately impacted, with associated economic impacts to energy production, states, and communities."

I wasn't sure if this is consistent with information in the proposal, etc. Let me know when you've had a chance to review and we can check in and discuss potential EPA participation.

Thanks!
Melissa

From: Ann Smith <apsmith@gsi-net.com>
Sent: Thursday, December 06, 2018 12:54 PM
To: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Eisele, Adam <Eisele.Adam@epa.gov>
Cc: Ric Bowers <rlbowers@gsi-net.com>
Subject: GSI's DOE Marginal Wells Study - Participation Request

Hi Melissa, Adam and Mark –

I hope you are well on this lovely, if not chilly, day. We enjoyed visiting with you all at the EPA Stakeholder Workshop a few weeks ago when Ric presented methane emission factor results from our DOE NETL gas storage well project.

Similar to the DOE NETL gas storage and compressors, we are hoping that EPA will participate on the Technical Advisory Steering Committee (TASC) for our new study being awarded by DOE NETL, *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells* (DE-FE0031702), to quantify and compare methane emissions at marginal and non-marginal wells: (https://www.netl.doe.gov/node/5775).

The goal of our study is to produce results that are *unbiased*, representative and appropriate to support recent and future proposed amendments to EPA's New Source Performance Standards (NSPS, 40 CFR Part 60, Subpart OOOOa). Please note that we will be providing responses by December 17, 2018 to EPA's proposed amendments of September 11, 2018, and will indicate that this study, planned for completion within 16 months, is anticipated to provide further data to support EPA's regulation decision-making.

The attached **Request for Participation** provides more details on the background and goals of the study, planned tasks and schedule.

Please let me know if you have time available next week to discuss the project in more detail, answer any outstanding questions and discuss your involvement in the study. We would be delighted to have EPA's participation.

Ann

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6 December 2018

GSI ENVIRONMENTAL

MEMORANDUM

TO: Potential Project Stakeholders – Regulatory Agencies

FROM: Ann P. Smith, P.E.; Richard L. Bowers, P.E.; GSI Environmental Inc. (GSI)

RE: Request for Participation - *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells Project (DOE NETL DE-FE0031702)*

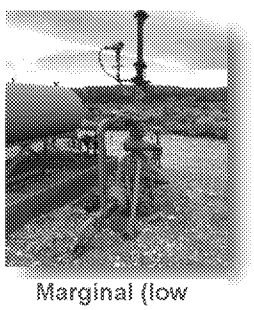
In order to promote appropriate policy making decisions, GSI Environmental Inc. (GSI) is soliciting your participation on an important new study under the U.S. Department of Energy to inform the regulators, the regulated community and others on the relative scale of methane emissions from marginal vs. non-marginal oil and gas wells.

We are seeking data, access to field sites, supplemental funding and/or technical steering committee participation to ensure that study results are unbiased, representative and appropriate to support recent and future proposed amendments to EPA's New Source Performance Standards (NSPS, 40 CFR Part 60, Subpart OOOOa).

This memorandum summarizes the scope and objectives of our study. Please consider the potential value of this study to all public and private stakeholders, and contact us regarding your questions, concerns and interest in supporting this important study.

BACKGROUND

The Environmental Protection Agency (EPA) issued a final rule on June 3rd 2016 (subsequently modified on 11 September 2018) to amend the New Source Performance Standards (NSPS, 40 CFR Part 60, Subpart OOOOa) to reduce methane emissions from new and modified oil and gas facilities. These Standards no longer exempt "low production well sites" (aka marginal or small wells), defined as sites with oil wells that produce <15 bbl per day or gas wells that produce <90 MCF per day, from Leak Detection and Repair (LDAR) requirements. Compliance with these regulations may impact all producers but, in particular, will affect small oil and gas operators of the ~785,000 marginal wells located throughout the United States. EPA's decision to not exclude marginal wells was based on limited methane emissions data. Therefore, a robust unbiased study is needed to quantify methane emissions from non-marginal wells.



Marginal (low producing) gas well in Clay Basin, UT

On 22 October 2018, the Department of Energy – National Energy Technology Laboratory (DOE NETL) selected *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells,* for award to GSI Environmental Inc. (GSI) to measure and compare methane emissions from marginal and non-marginal well sites at various basins across the United States. The project will involve i) compilation and evaluation of data from published studies and operators, ii) field measurement of methane emissions from marginal and non-marginal wells, and iii) identification of opportunities to reduce marginal wellsite emissions. As is typical and critical on all DOE NETL projects, technology transfer activities will be facilitated during the course of the project to convey results and gain feedback from critical stakeholders.

OVERALL PROJECT PLAN

The project will be completed within 16 months. Up to three basins, depending on funding availability, will be measured during this study. Basins will be selected considering criteria such as oil-to-gas ratio, wet vs dry gas or other variables. Depending on the availability of additional funding, Field Campaign C could be expedited as long as final data usability is not compromised.

The project includes the following major tasks:

- robust data source assessment to identify critical data gaps;
- Master Workplan to specifically address key data gaps and, accordingly, direct the overall approach of the field data collection, evaluation and reporting process;
- field campaigns in up to three major U.S. region/basins (Regions A/B/C);
- data processing and analysis; and
- Comprehensive Project Report to summarize study activities, results and conclusions.

DATA SOURCE ASSESSMENT AND MASTER WORKPLAN

A robust data source assessment will be completed to address key data gaps and improve understanding of marginal and non-marginal well methane emissions. Key subtasks include:

- Literature survey of published, peer-reviewed scientific articles to assess quantity, quality, representativeness and usability of data from previous studies;
- *Blind* survey of oil and gas producing companies on key site characteristics, metrics and (optional) activity data (*i.e., names of industry participants, locations of sites and site characteristics will remain confidential and will not be provided to anyone outside of the GSI project team*);
- Development of GIS-linked/enabled database of usable data from literature and operator survey;
- Identification of gaps in current understanding of emissions from marginal vs. non-marginal wells.

Specific data we will obtain from oil and gas marginal and non-marginal well facilities includes:

- General location information (site names, identification numbers, County, State and Basin location, Well type (e.g., natural gas, oil))
- Well condition (e.g., storage, injection, producing, shut-in, plugged, abandoned)
- Equipment types and counts (e.g., wells, separators, compressors, storage tanks, dehydrators, flares, thermal conductors)
- Equipment characteristics (e.g., age, size)
- Production rate (e.g., bbls of oil, MCF gas)
- Existing emissions control devices (e.g., vapor recovery units, flares, enclosed combustion devices)

The results of this assessment will support development of a Master Workplan for the remainder of the study to formulate scientific questions to be answered, refine project objectives/scope, if needed, and identify emissions source characterization/classification criteria, site selection criteria, emissions screening and measurement technology options and selection criteria, to establish appropriate levels of accuracy, representativeness and statistical power of data among different regions.

Critical Outcome/Action/Deliverable: *Identification of specific scientific questions to be answered, and/or hypotheses to be tested, during highly focused field investigations. Report combining data source assessment and Master Workplan. Technical steering committee calls with stakeholders to communicate results and solicit feedback.*

SITE/TECHNOLOGY SELECTION AND FIELD CAMPAIGN WORKPLAN – REGIONS A/B

Populations of desirable/candidate regions/basins (e.g., Permian, Appalachian, Uintah) will be identified based on operator survey results, geographic factors and other available information, such as publically-available well production data, and screened for selection. GIS algorithms will be used to optimize field site selection, based on criteria established in prior tasks, relevant candidate site attributes (e.g., numbers/types of emission sources), and applicable time and geographic constraints (e.g., geographic distribution, and travel times from site to site,) and to minimize any potential bias.

The key to this approach is the focused, statistically-based selection of *representative* field sites to be included for screening and measurement. We will seek to maximize the representativeness of region-wide emissions estimates from marginal vs. non-marginal oil and gas wells by the optimum selection of sites. Appropriate screening and measurement methodologies will be selected based on the nature and magnitude of specific emission sources for which data are needed.

Critical Outcome/Action/Deliverable: *Region-specific data collection and analysis protocols, health and safety and QAQC plans. Meeting with site owner/operator representatives (via Regional steering committees) and other stakeholder advisory groups, as necessary, to review results and proposed activities.*

FIELD CAMPAIGN - REGIONS A/B

Field campaigns in Regions A and B (to be determined) will include a survey of selected producing well sites to detect, classify, count, and quantify emissions from representative populations of key sources. We expect to characterize emissions from 100 to 200 well sites over a period of five to seven weeks in each region with the goal of applying resultant data to estimate region wide marginal vs. non-marginal well emissions. Actual numbers of well sites where emissions are screened and measured will be dictated by the specific technology employed, the distances among target well site locations, and other possible factors, which may vary by site/region.

A field team of approximately four researchers will characterize populations and the frequency of emissions from key emissions sources at each type of well site. This survey will include a census of all pertinent emission sources (e.g., major equipment components, storage tanks and, if possible, episodic events such as liquids unloadings, based on operator-provided information) and a qualitative screening for observed emissions, comparable to what is performed for a typical LDAR program to first identify leaking sources. Emissions measurements will be carried out by qualified field measurement/data collection teams from participating subcontractor universities using specific measurement methods and technologies determined in prior tasks.

Critical Outcome/Action/Deliverable: *Emissions screening and measurement data from representative populations of marginal vs. non-marginal wells sites in each region.*

DATA PROCESSING AND ANALYSIS – REGIONS A/B

All collected field data will be compiled and validated per applicable quality assurance/quality control (QA/QC) procedures to assess its usability for further analysis in the estimation of representative emissions estimates for each type of well site. Depending on the needs of the study, data will be grouped into related clusters, statistical probability distributions will be determined, and appropriate statistics (e.g., 95% confidence intervals) will be calculated using standard parametric or nonparametric procedures in order estimate equipment or process-specific and/or total methane emission rates from observed operations and activities.

Critical Outcome/Action/Deliverable: *Characterization of region-wide frequency and magnitude of marginal vs. non-marginal wellsite emissions. Technical steering committee calls with stakeholders to communicate results and solicit feedback.*

SITE SELECTION AND FIELD CAMPAIGN WORKPLAN – REGION C

Depending on available funding, a third desirable/candidate region/basin (Region C) will be identified for study similar to Regions A/B. Appropriate screening and measurement methodologies will be selected based on the nature and magnitude of specific emission sources for which data are needed in this region. Depending on the availability of resources, Field Campaign C could be expedited as long as final data usability is not compromised.

Critical Outcome/Action/Deliverable: *Region-specific data collection and analysis protocols, health and safety and QAQC plans. Meeting with site owner/operator representatives (via Regional steering committees) and other stakeholder advisory groups, as necessary, to review results and proposed activities.*

FIELD CAMPAIGN – REGION C

The field campaign in Region C will mirror those in Region A/B incorporating any changes identified at the end of campaigns A/B, as long as they maintain consistency and usability of data. Qualified field measurement/data collection teams from participating subcontractor universities will be engaged based on comparable prior field experience, ability to provide comparable equipment, and geographic proximity to the studied region.

Critical Outcome/Action/Deliverable: *Emissions screening and measurement data from representative populations of marginal vs. non-marginal wells sites in region.*

DATA PROCESSING AND ANALYSIS – REGION C

All collected field data will be compiled and validated in a process similar to Region A/B data, incorporating any changes identified at the end of campaigns A/B, as long as they maintain consistency and usability of data.

Critical Outcome/Action/Deliverable: *Characterization of region-wide frequency and magnitude of marginal vs. non-marginal wellsite emissions. Technical steering committee calls with stakeholders to communicate results and solicit feedback.*

COMPREHENSIVE PROJECT REPORT

The combined study results over all investigated regions (A, B, and C), including operator-provided activity data, frequency of emissions from key sources, and the magnitude of such emissions based on measurements collected at representative fractions of each type of emitting source, will be analyzed and interpreted, as a whole, to assess possible regional differences and,

if feasible, make predictions regarding marginal vs. non-marginal well site emissions in other oil and gas producing regions not included in this study. In addition, study conclusions will focus on opportunities to reduce marginal wellsite emissions at minimal cost so that marginal well production can remain economically viable.

Critical Outcome/Action/Deliverable: *Technical steering committee calls with stakeholders to discuss key findings and conclusions of the study. Final report summarizing and comparing emissions among significant marginal and non-marginal well site populations in all regions. Meeting with site owner/operator representatives (via Regional steering committees) to review methane emission results and sources.*

TECHNOLOGY TRANSFER

GSI's ultimate goal for technology transfer is to transfer knowledge from this project to industry, regulatory bodies, environmental organizations, research community, and the general public through the following activities:

- Publication of peer-reviewed technical papers (team, annually).
- Presentations at conferences and workshops (team, multiple events annually).
- Public education through academic institutions (CSU, USU etc.)

SUPPLEMENTAL FUNDING

As mentioned above, GSI is requesting data, access to field sites, supplemental funding and/or technical steering committee participation to produce study results that are unbiased and representative of methane emissions from marginal and non-marginal oil and gas wells. Please note that *all financial contributions will go directly through DOE NETL (e.g., in accordance with interagency funding requirements) or to university team members to support implementation of field programs.*

PROJECT SCHEDULE

The project is being funded by DOE-NETL to investigate up to three regions, depending on funding availability, over a duration of 16 months in accordance with the following schedule of tasks, milestones, and deliverable documents.

GSI ENVIRONMENTAL

Project Schedule

	Task / Description	Month 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Phase I - Project Development																	
1	**Project Management and Planning**																
	Project Management Plan																
	Technology Transfer Plan																
	Data Management Plan																
2	**Data Source Status Assessment**																
3	**Master Workplan**																
	Data Source Summary Report and Master Workplan																
	Master Workplan complete																
Phase II(a) - Region A Field Investigation																	
4a	**Site/Technology Selection**																
5a	**Region A Field Campaign Workplan**																
	Field Campaign Workplan																
6a	**Region A Field Campaign**																
7a	**Data Processing and Analysis**																
	Interim Results Summary - Region A																
	Region A Field Investigation Complete																
Phase II(b) - Region B Field Investigation																	
4b	**Site/Technology Selection**																
5b	**Region B Field Campaign Workplan**																
	Field Campaign Workplan Ammendment																
6b	**Region B Field Campaign**																
7b	**Data Processing and Analysis**																
	Interim Results Summary - Region B																
	Region B Field Investigation Complete																
Phase II(c) - Region C Field Investigation																	
4c	**Site/Technology Selection**																
5c	**Region C Field Campaign Workplan**																
	Field Campaign Workplan Ammendment																
6c	**Region C Field Campaign**																
7c	**Data Processing and Analysis**																
	Interim Results Summary - Region C																
	Region C Field Investigation Complete																
Phase III - Reporting																	
8	**Comprehensive Project Report**																
	Final Report																
	Final Report Complete																
9	**Technology Transfer**																

Milestone
Deliverable

PLEASE CONTACT US FOR MORE INFORMATION ON PARTICIPATION

Ann P. Smith	(512) 346-4474	apsmith@gsi-net.com
Richard L. Bowers	(512) 346-4474	rlbowers@gsi-net.com

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Message

From: Rich Haut @ Info Rpsea.org [info@rpsea.org]
Sent: 8/26/2019 7:39:08 PM
To: Richard Haut [rhaut@rpsea.org]; Ric Bowers [rlbowers@gsi-net.com]; Ann Smith [apsmith@gsi-net.com]
Subject: Notes from August 5 and 6 Marginal Wells Emission Study Technical Advisory Steering Committee
Attachments: GSI Marginal Well Emissions Study_August TASC Summary.pdf

Good afternoon,

Please see the attached summary notes from the August 5 and 6 TASC calls. A copy of the slide presentation is also included in the PDF document.

If you have any questions, please don't hesitate to contact me.

Thank you.

Richard C. Haut, Ph.D.
President
Research Partnership to Secure Energy for America (RPSEA)

GSI ENVIRONMENTAL

MEMORANDUM

TO: TASC Participants

FROM: Richard L. Bowers, P.E., and Ann P. Smith, P.E., GSI Environmental Inc.

RE: Summary of Technical Advisory Steering Committee Calls, August 2019; *DOE-NETL DE-FE0031702 Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells*

INTRODUCTION

GSI Environmental Inc. (GSI) hosted the second of a series of technical advisory committee (TASC) calls with representatives from the oil and gas industry, regulatory agencies, governmental and non-governmental organizations and academia to discuss ongoing activities of the above referenced project, funded by the U.S. Department of Energy, Office of Fossil Fuels. A total of four calls covering identical topics were held on August 5 and 6, 2019, to discuss the results and findings of the recently completed *Data Source Status Assessment Report and Master Workplan*, including site selection criteria for the upcoming field investigations, and solicit feedback from project participants.

With your feedback, the research team is now preparing a detailed *Regional Workplan* for the initial field campaign, which will commence in the coming weeks in the Appalachian and Illinois Basins. To ensure all needed data are collected in a safe, consistent and defensible manner, the Regional Workplan includes: i) specific protocols and/or procedures for applicable emissions screening and measurement techniques; ii) information on a variety of operating equipment and conditions expected to be encountered in the field; iii) guidelines for documenting "site activity data"; iv) QA/QC procedures and criteria; and v) a region-specific health and safety plan.

Slides presented by GSI during the August 2019 TASC calls are provided as Attachment A and summarize the major topics of discussion. This memo summarizes questions, responses and additional points of discussion raised during the four calls, collectively.

PROJECT OVERVIEW

The study aims to characterize nature and magnitude of methane emissions—in particular fugitives—from representative populations of marginal oil and gas production sites in multiple geographic regions. Well operators throughout the U.S. have been requested to participate in the study by way of i) providing data about their production operations; ii) providing access to potential field sites for emissions screening and measurements; iii) participating on the project advisory committees; and iv) providing supplemental funding (cost share), in accordance with federal government requirements for funding the project. Based on the availability of existing data and project resources, the field measurement campaigns are being designed to represent the diversity of marginal well operations.

Has the research team met with EPA or DOE concerning amendments to OOOOa?

EPA is tracking the study, and agency technical experts are engaged with the research team through participation on the TASC and additional dialogue.

Does this study plan to address the non-marginal well population?

The study team has allotted a limited amount of time to sample non-marginal wells for comparison with marginal wells sampled by the same approach. Considerations for comparing results from marginal and non-marginal wells will be detailed in the Regional Workplan.

LITERATURE REVIEW

Attachment B lists the literature reviewed for this study.

Which of the seven statements on Slide 9 does this study reject / question / accept?

This study has no pre-determined outcome. The intent of this study is to produce a robust and defensible dataset, which may substantiate or refute any of the statements.

OPERATOR SURVEY (QUESTIONNAIRE)

How did you determine the number of sites?

GSI defined sites in the survey based on physical locations. This information was provided by operators responding to the survey.

Did survey request the age and depth of wells?

The survey asked for the average age of wells and facilities. This information was basin- and product-specific, but not specific to the formation or well depth.

What is the proportion of marginal versus non-marginal wells?

While operators were encouraged to provide data for non-marginal wells in addition to their marginal well data, most opted to not to do so. Responses to date represent 87,103 marginal and 2,215 non-marginal oil and gas wells.

What is the proportion of conventional versus unconventional wells?

The survey did not specifically ask about conventional versus unconventional production; however, it is probably reasonable to assume that most wells at single-well locations (97% of wells reported in the survey) are conventional and those at sites with three or more wells are unconventional (2% of wells reported in the survey).

What was the QA / QC process when reviewing the survey data?

The study team reviewed all completed survey questionnaires using a combination of manual (qualitative) and automated (quantitative) checks to ensure responses were entered correctly and consistently. Where inconsistencies were identified, the team contacted the operator to verify the accuracy of the reported information or, in some cases, make needed corrections.

Are there any regions where you need additional data?

Yes, more data and, more importantly, potential access to field sites is needed from additional operators in the Permian Basin to ensure the representativeness of the study in that region. Regions with prevalent marginal well populations that, to date, are not represented by responses to the survey include the San Juan Basin (Four Corners area) and California.

Do the current survey results primarily consist of results from one operator?

No, multiple operators have provided data at many scales of response in terms of numbers of wells, ranging from less than ten to tens of thousands per operator. The study team believes the conclusions drawn regarding the diversity of well types and production conditions throughout the country are not significantly biased by the scale of response by any single company.

Is there survey input from independents / small operators?

Yes, but we encourage additional small operators from all regions of the country to still provide the requested data on their operations, which will aid later in interpretation of field results.

Does participation in the survey imply site access for the field study?

No, the project team will separately contact operators regarding potential site access in areas targeted for the field campaigns.

Do you have data on the volume of gas emitted to the atmosphere?

No, that information was not requested in the survey. The study team will try to collect this information for sites visited during the field campaigns.

FIELD DATA COLLECTION

How will the study team ensure the long-term representativeness of observed and measured emissions at each field site?

The study team intends to collect extensive activity data at each visited site. Of critical importance to this effort is detailed information to be shared by the host operator regarding onsite operations and the expected temporal variability of emissions observed (and not observed) at the time of sampling vs. at other times. Considerations of potential temporal differences which could affect the representativeness of observed emissions should include daytime vs. nighttime conditions, seasonally variable conditions, and periodic operations cycles (e.g. where wells are operated only a few days per month or differently at different times).

How will field measurements address intermittent emissions from episodic events?

The sampling team will document any high emission events observed while onsite.

What is the timing for the field data collection?

As early as September 2019 and continuing through March 2020.

Will the field study use random site selection?

Yes. To maintain the integrity of an unbiased selection of field sites, we request participating host operators to provide *potential* access to an unbiased selection of candidate field sites (e.g. all sites, or sites within a defined geographic boundary) and not to alter operations in anticipation of any site being selected for the field study. Actual field sites will be selected at random from among candidate sites.

What kind of training will the field team have?

All field personnel will have necessary safety training and certificates and will be generally informed of the nature of operations, equipment, and conditions to be expected at visited sites.

Personnel conducting emissions screening and measurements will receive advance hands-on training on the applicable protocols and equipment to ensure consistency in the data collection procedures.

Will there be another TASC call to discuss the Regional Workplan?

None is planned at this time. The study team will make the final *Data Source Status Assessment Report and Master Workplan* and draft *Regional Workplan* available to all TASC participants for review and comment upon request.

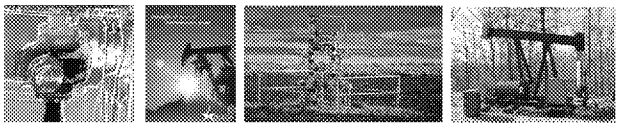
QUANTIFICATION OF METHANE EMISSIONS FROM MARGINAL OIL & GAS WELLS

DOE NETL Project DE-FE0031702

U.S. DEPARTMENT OF ENERGY

NATIONAL ENERGY TECHNOLOGY LABORATORY

GSI ENVIRONMENTAL



Richard L. Bowers, P.E., BCEE, rlbowers@gsi-net.com
Ann P. Smith, P.E., BCEE, apsmith@gsi-net.com

1

INTRODUCTION
Who We Are

GSI ENVIRONMENTAL

WHO	Consultants in environmental science and engineering
WHERE	Offices in Houston, Austin, Irvine, Oakland; Completed environmental projects throughout the U.S. and worldwide
WHEN	Founded 1986
WHAT	M.S. and Ph.D. Engineers, Scientists, Hydrologists, Hydrogeologists, Regulatory Permitting experts, Software Developers, Database/GIS Professionals, Field Techs, Expert Witness Staff

KEY POINT: Environmental engineering projects for Oil & Gas industry, chemical manufacturers, law firms, R&D organizations, and government agencies.

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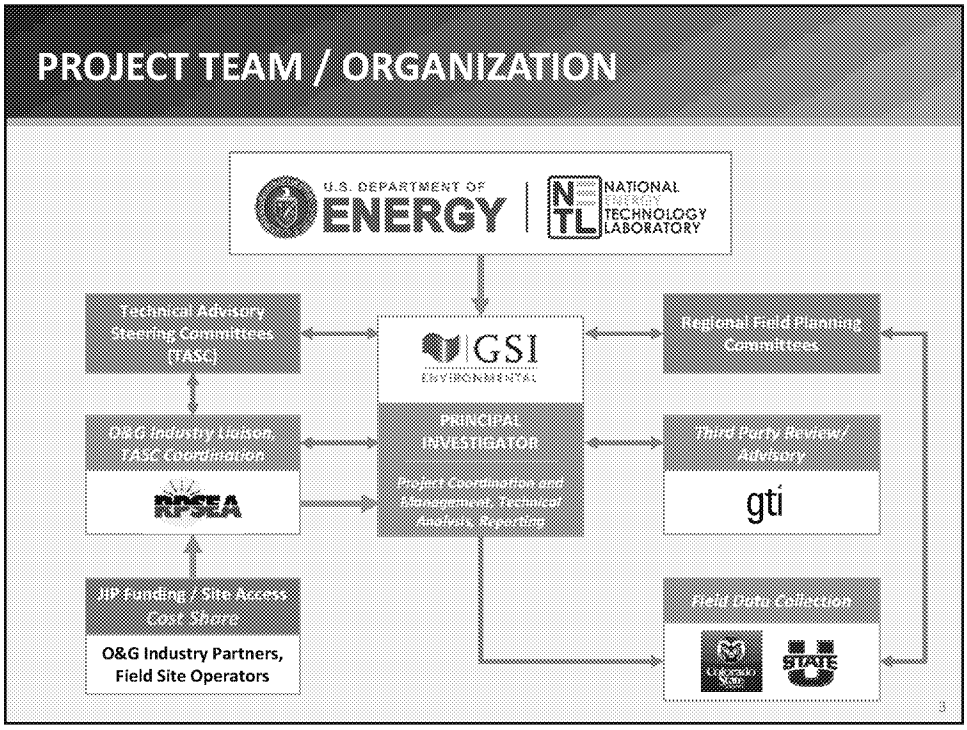
PROJECT TEAM / ORGANIZATION
U.S. DEPARTMENT OF ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY
Technical Advisory Steering Committee (TASC)
GSI ENVIRONMENTAL
Regional Field Planning Committees
O&G Industry Liaison, TASC Coordination
RPSEA
PRINCIPAL INVESTIGATOR
Project Coordination and Management, Technical Analysis, Reporting
Third Party Review/ Advisory
gti
JIP Funding / Site Access Cost Share
O&G Industry Partners, Field Site Operators
Field Data Collection
STATE
3

3

1
PROJECT OVERVIEW
4

4

STUDY QUESTIONS TO ANSWER

- **How do marginal vs. non-marginal wells compare in terms of:**
  - Production rates?
  - Type and quantity of equipment?
  - Frequency/timing of episodic high-emission events?
  - Equipment type/age/condition?
  - Absolute contribution to total emissions?
- **Correlations of site characteristics to emissions**
- *How significant are marginal wells emissions?*

KEY POINT: **Need equipment-specific analysis to compare marginal vs. non-marginal wells.**

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OVERALL STUDY APPROACH

- **Desktop Study / Data Mining** (3 mo.)
  - Literature and operator surveys
  - Database compilation / statistical analysis
- **Field Investigations** (~12 mo.)
  - Statistically-based sampling design
  - Multiple production basins/regions
  - Established measurement protocols
- **Messaging and Communication**
  - Engagement with industry, state regulators, EPA, etc.
  - Project Reporting

Emissions Detection/Screening

Emissions Measurement

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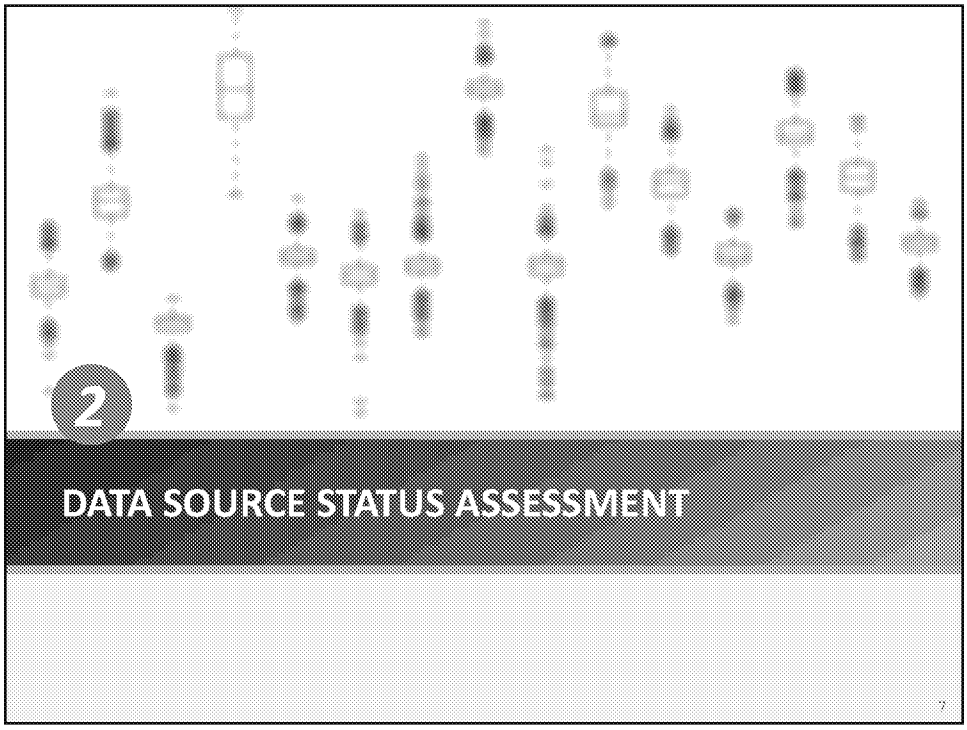

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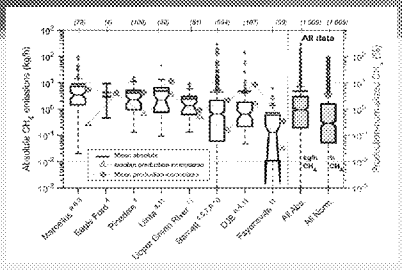
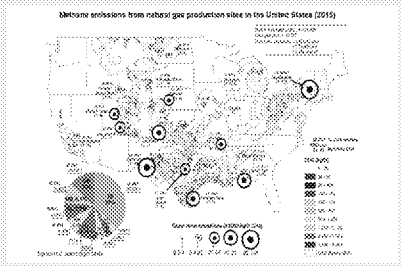
LITERATURE REVIEW - *O&G Production-Related Emissions*

- 45 articles published between 2010 and 2019
- Site-level methane emissions data
- Coverage of ~9 US producing basins; but *Low-production sites not well represented*
- Variety of emissions measurement/ estimation techniques
- Limited site-level activity data
  - Major equipment / Emission sources?
  - Operations data
  - Equipment-level emissions
- Absolute vs. production-normalized emissions estimates





Omara et al. (2018)

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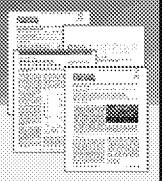
8

PUBLISHED FINDINGS - *What's Reported*



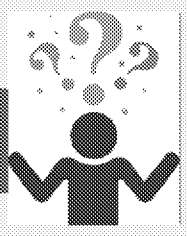
1. Marginal wells may contribute a larger proportion of overall emissions by the oil and gas production sector than previously assumed.
2. Correlations may exist between methane emissions and certain site characteristics such as natural gas production rate, well age, and equipment counts.
3. Site-level activity data improves the quality of site-level emissions estimates and may help resolve discrepancies between top-down and bottom-up approaches.
4. Certain types of equipment and components frequently represent the largest sources of measured methane emissions in the natural gas production sector.
5. Certain operational processes, such as liquids unloading and abnormal operating conditions, may represent the largest (and mostly unquantified) percentage of methane emissions in the natural gas production sector.
6. Emission estimates from the EPA Greenhouse Gas Inventory (GHGI), as well as those reported in the Greenhouse Gas Reporting Program (GHGRP), *may* be biased low for the natural gas production sector.
7. Additional information is needed to assess the impact and contribution of methane emissions from marginal oil and gas wells.

9

9

KEY DATA GAPS *What we don't know*

- Diversity and range of physical and operational characteristics of distinctive production site populations
  - Activity data (e.g. major equipment counts)
  - Frequency, timing, and duration of high-emission events
- Distribution of methane emissions from low-production sites



Site-level activity data and emissions measurements are needed to better characterize methane emissions from low-production sites.

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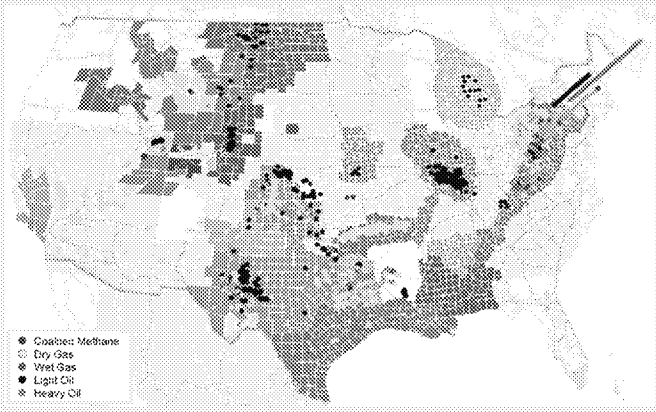
PRODUCTION OPERATORS SURVEY - *Data Blinded*



Site location

- *Basin, state, county, etc.*

Activity data

- *Production type and rate*
- *Liquids unloading, associated gas disposition*
- *Emissions monitoring*

Major equipment

- *Active/Inactive Wells*
- *Tanks, separators, dehydrators, etc.*
- *Flares/thermal combustors*
- *Equipment components (e.g., pneumatic devices)*

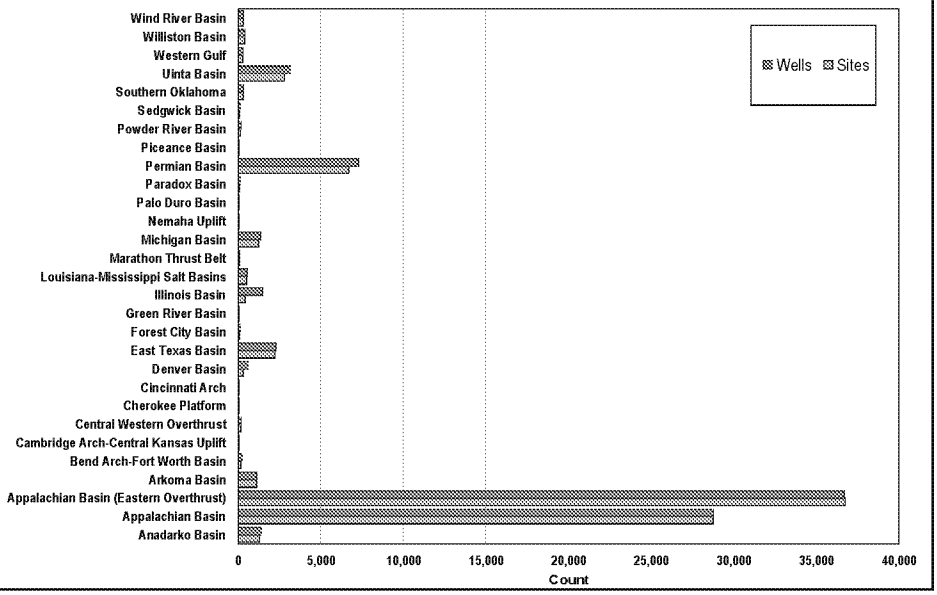
OPERATOR RESPONSES TO DATE: ~86,700 wells, 29 basins, 23 states. MORE TO COME!

KEY POINT: Higher levels of participation/response produces better results.

11

11

SURVEY RESPONSE BY BASIN



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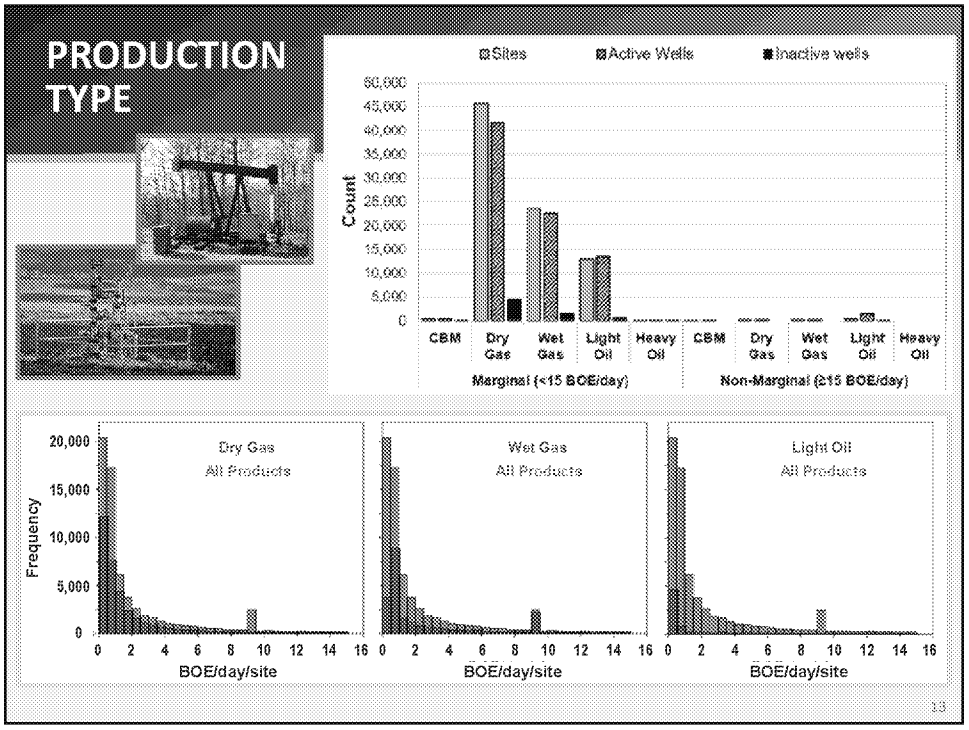
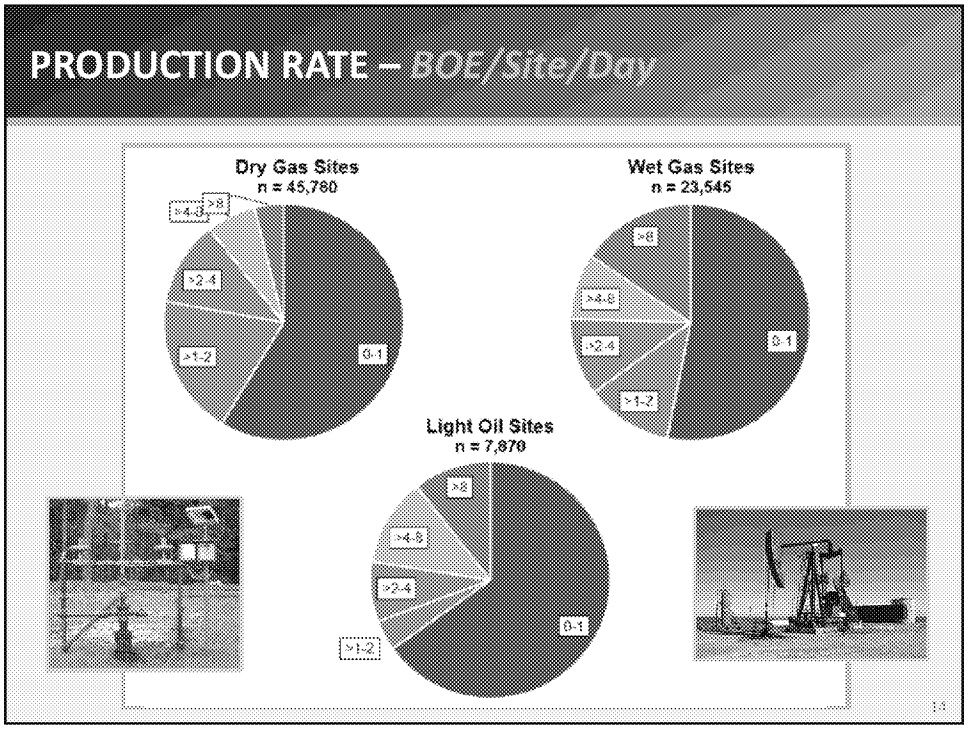
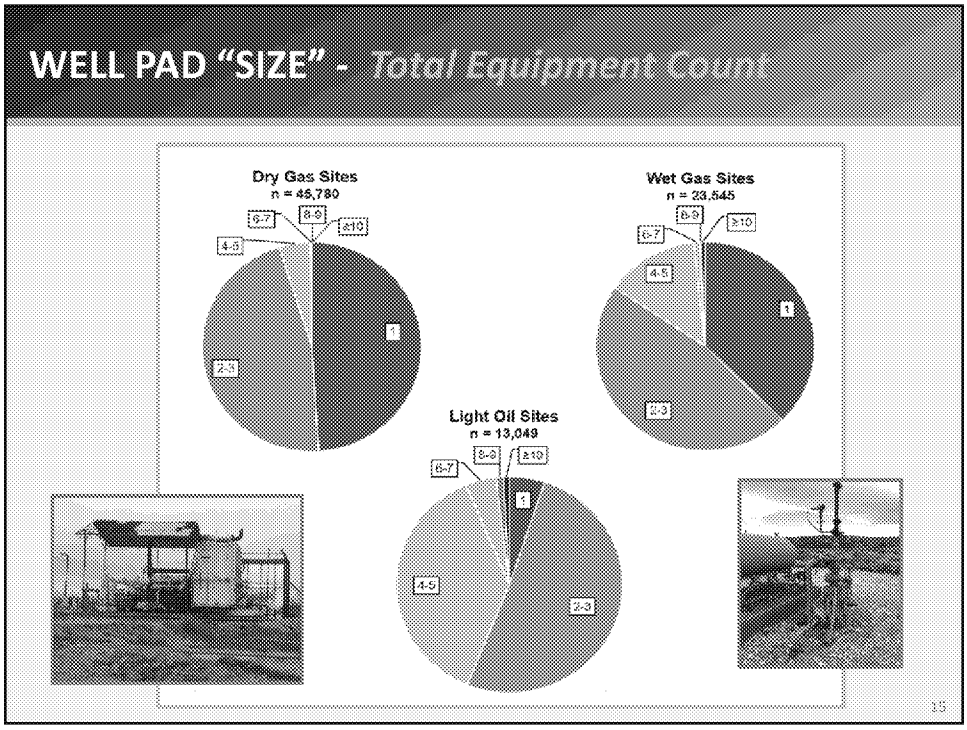

PRODUCTION TYPE
Sites
Active Wells
Inactive wells
Count
CBM
Dry Gas
Wet Gas
Light Oil
Heavy Oil
Marginal (<15 BOE/day)
Non-Marginal (≥15 BOE/day)
Dry Gas
All Products
Wet Gas
All Products
Light Oil
All Products
Frequency
BOE/day/site
13

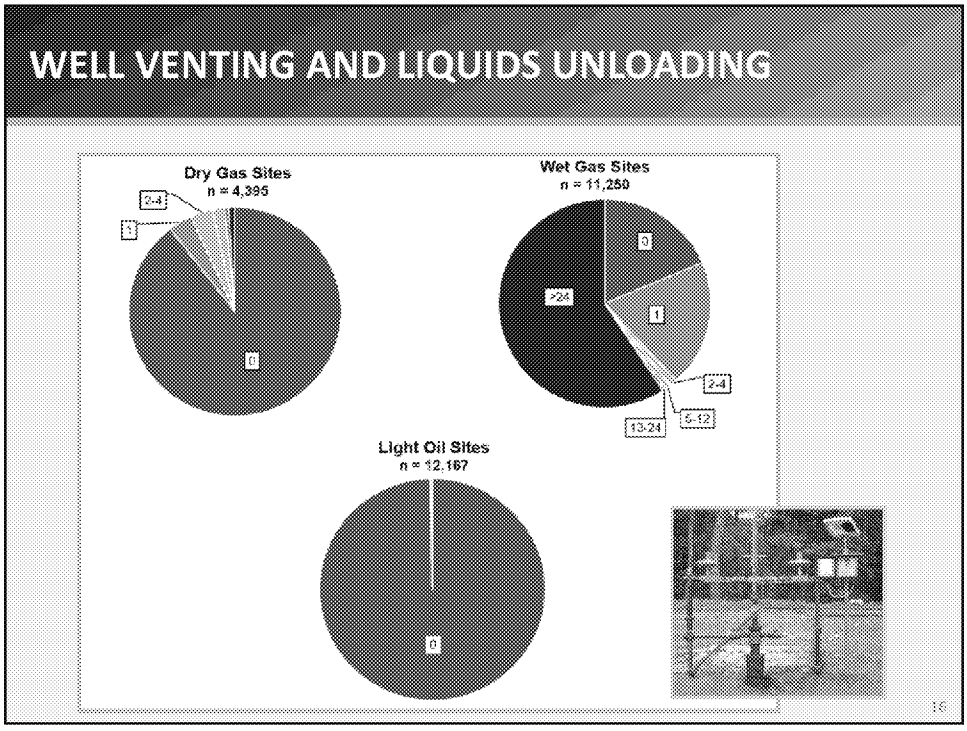
13


PRODUCTION RATE – BOE/Site/Day
Dry Gas Sites
n = 45,760
Wet Gas Sites
n = 23,545
Light Oil Sites
n = 7,870
0-1
>1-2
>2-4
>4-8
>8
14

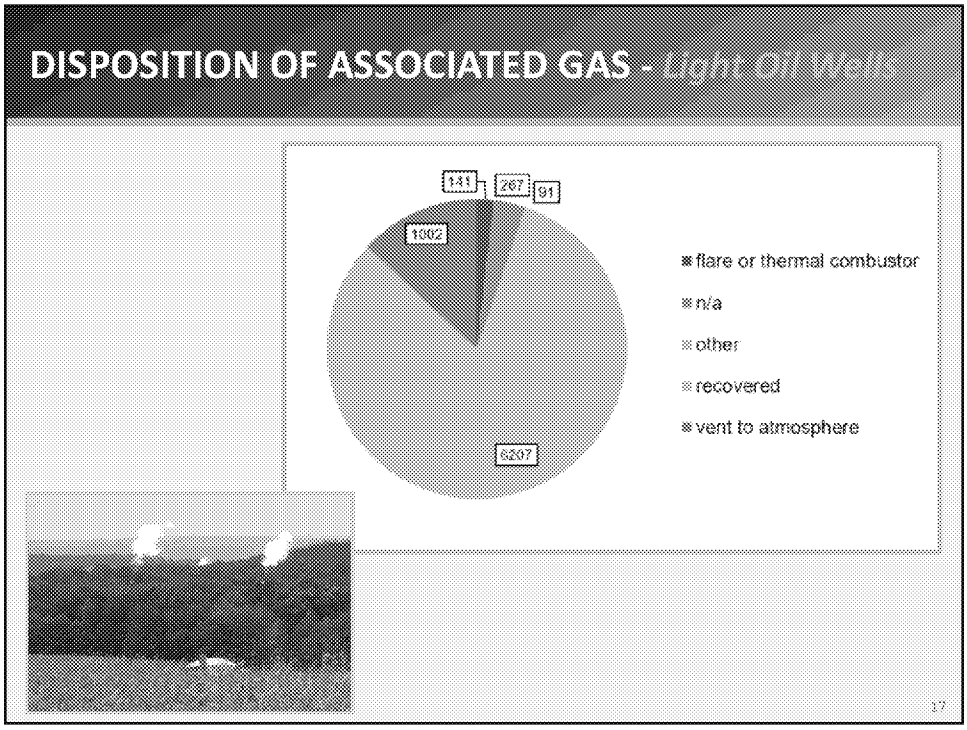
14


WELL PAD "SIZE" - Total Equipment Count
Dry Gas Sites
n = 45,780
Wet Gas Sites
n = 23,545
Light Oil Sites
n = 13,049
0
1
2-3
4-5
6-7
8-9
≥10
15

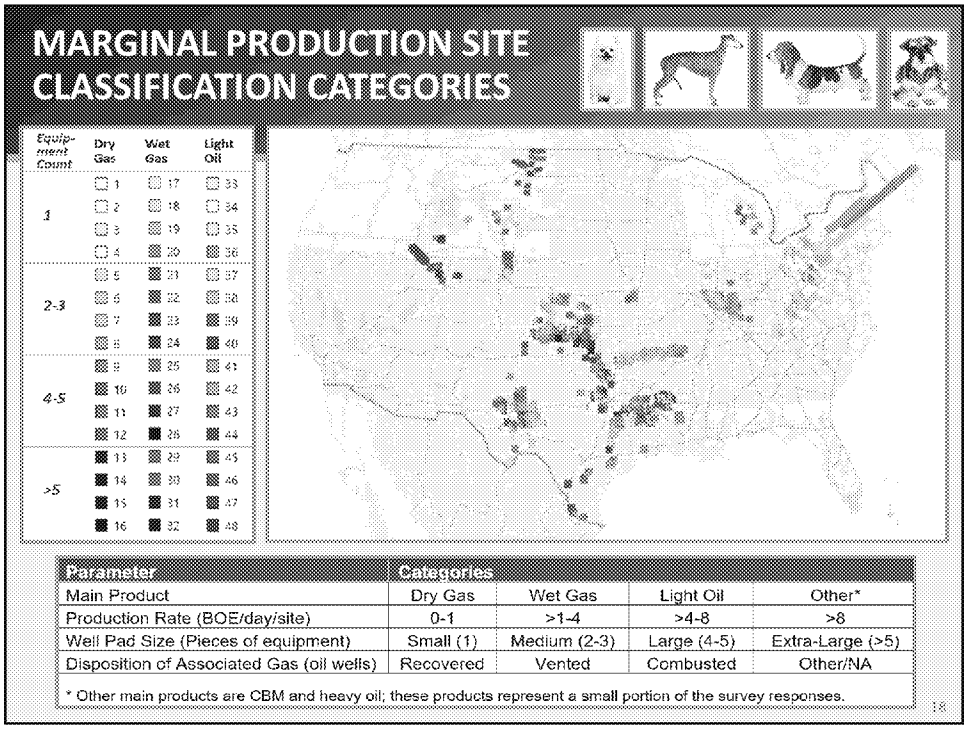
15


WELL VENTING AND LIQUIDS UNLOADING
Dry Gas Sites
n = 4,395
Wet Gas Sites
n = 11,250
Light Oil Sites
n = 12,167
0
1
2-4
5-12
13-24
>24
16

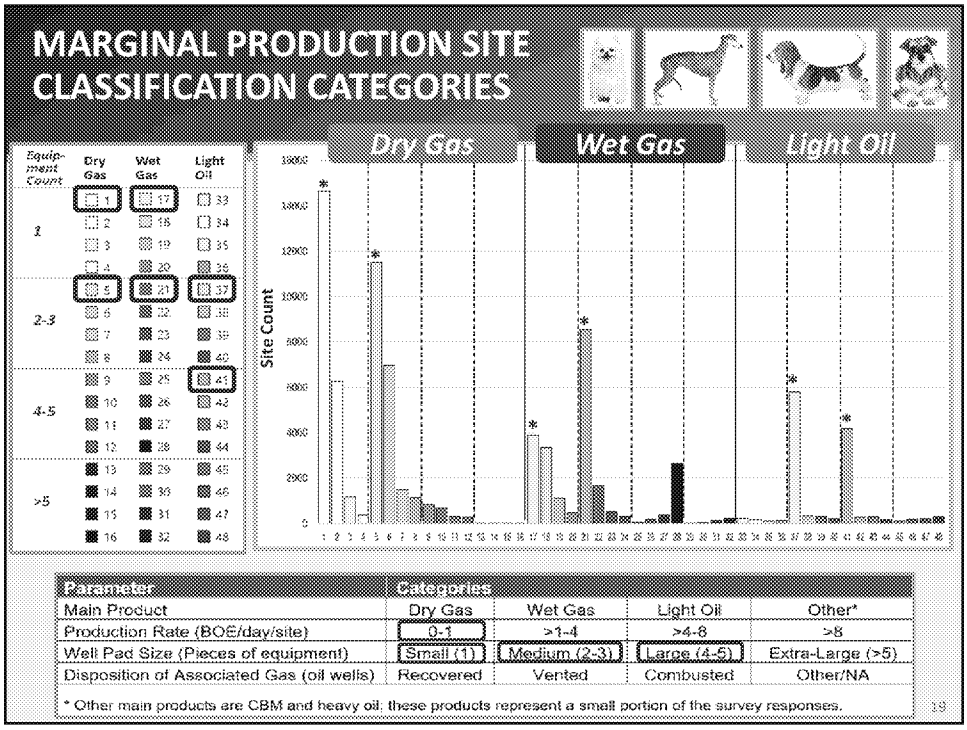
16


DISPOSITION OF ASSOCIATED GAS - Light Oil Wells
141
267
91
1002
6207
flare or thermal combustor
n/a
other
recovered
vent to atmosphere
17

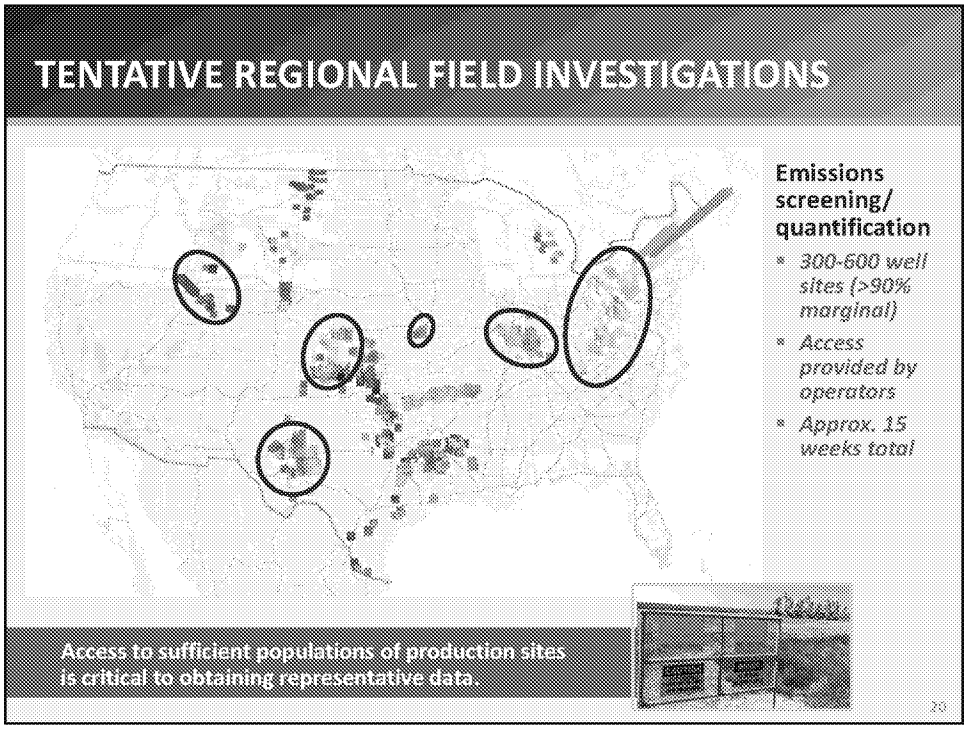
17


MARGINAL PRODUCTION SITE CLASSIFICATION CATEGORIES
Equipment Count
Dry Gas
Wet Gas
Light Oil
1
2-3
4-5
>5
Parameter
Categories
Main Product
Dry Gas
Wet Gas
Light Oil
Other*
Production Rate (BOE/day/site)
0-1
>1-4
>4-8
>8
Well Pad Size (Pieces of equipment)
Small (1)
Medium (2-3)
Large (4-5)
Extra-Large (>5)
Disposition of Associated Gas (oil wells)
Recovered
Vented
Combusted
Other/NA
* Other main products are CBM and heavy oil; these products represent a small portion of the survey responses.
18

18


MARGINAL PRODUCTION SITE CLASSIFICATION CATEGORIES
Dry Gas
Wet Gas
Light Oil
Equipment Count
Dry Gas
Wet Gas
Light Oil
1
2-3
4-5
>5
Site Count
Parameter
Categories
Main Product
Dry Gas
Wet Gas
Light Oil
Other*
Production Rate (BOE/day/site)
0-1
>1-4
>4-8
>8
Well Pad Size (Pieces of equipment)
Small (1)
Medium (2-3)
Large (4-5)
Extra-Large (>5)
Disposition of Associated Gas (oil wells)
Recovered
Vented
Combusted
Other/NA
* Other main products are CBM and heavy oil; these products represent a small portion of the survey responses.
19

19


TENTATIVE REGIONAL FIELD INVESTIGATIONS
Emissions screening/ quantification
300-600 well sites (>90% marginal)
Access provided by operators
Approx. 15 weeks total
Access to sufficient populations of production sites is critical to obtaining representative data.

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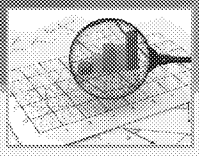
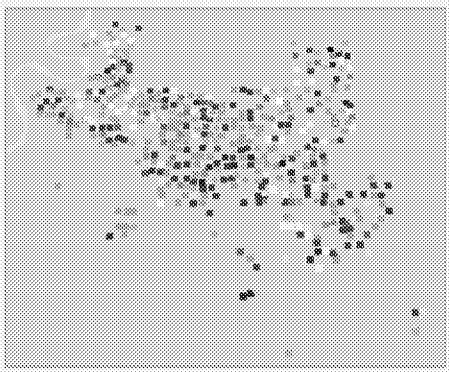
MASTER WORK PLAN



Field Investigation Design

- Site selection (Criteria, procedures)
  - Representativeness **of field sites**
- Technology specifications (Equipment, methods, protocols, etc.)
  - Emissions Screening **- ID and characterize nature and frequency of key methane emission sources**
  - Emissions Measurement **- Quantify emissions from representative emitting sources.**
- Data analysis (Criteria, procedures)



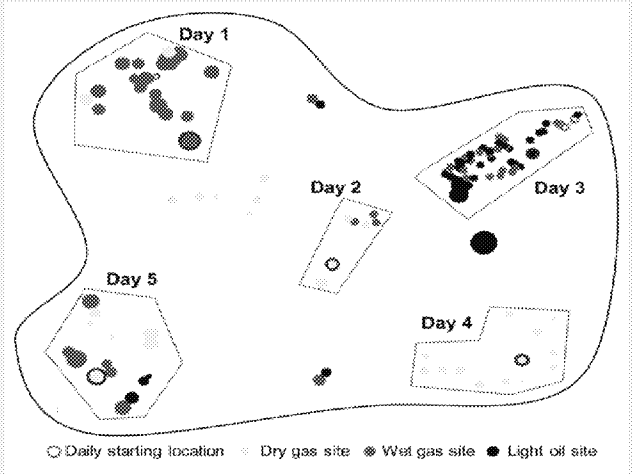
Example map with site classifications identified in different colors

22

22

REGIONAL CLUSTERING EXAMPLE
One Week of Sampling Locations

- Pre-planned
- Primary site for each day
- Secondary sites each day
- Driving order for planning purposes



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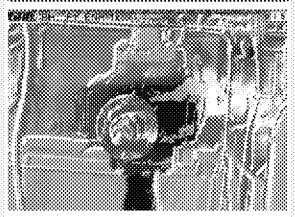
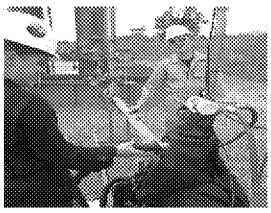
ON-SITE EMISSION DETECTION AND QUANTIFICATION

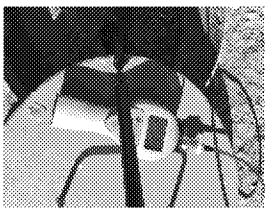
Optical Gas Imaging



High Flow Sampler



Gas "Sniffer"



- Vented and fugitive emissions
  - *Opgal Eye-C-Gas IR camera*
  - *Bacharach Hi-Flow sampler*
  - *Bascom-Turner Gas Raver*
- Exhaust Combustion Slip Measurement
  - *MKS-2303 FTIR*

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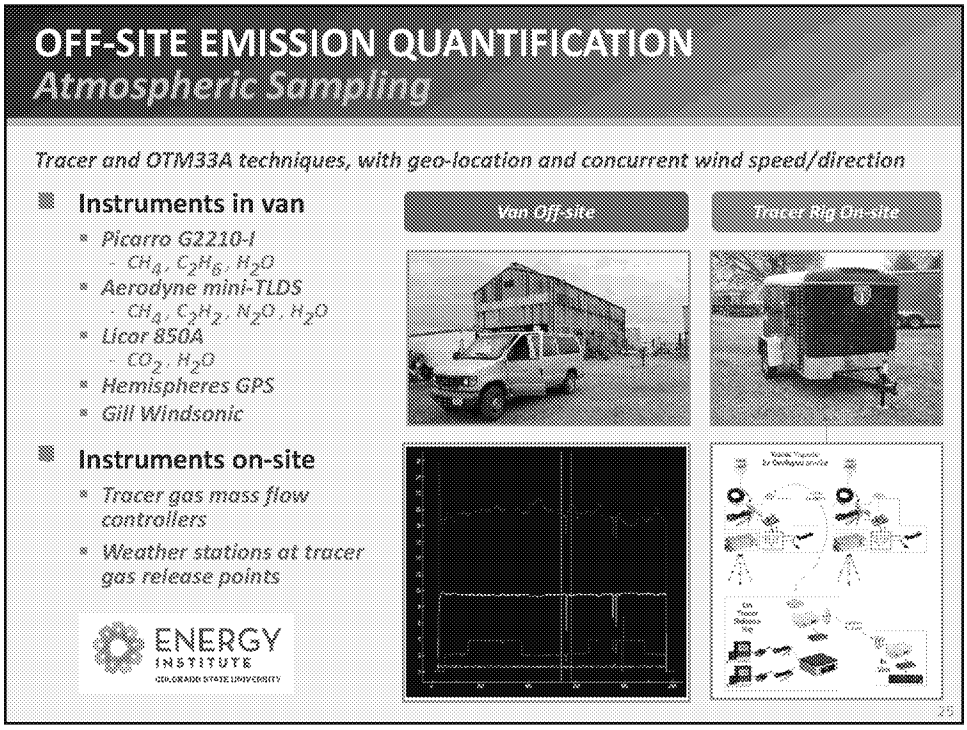
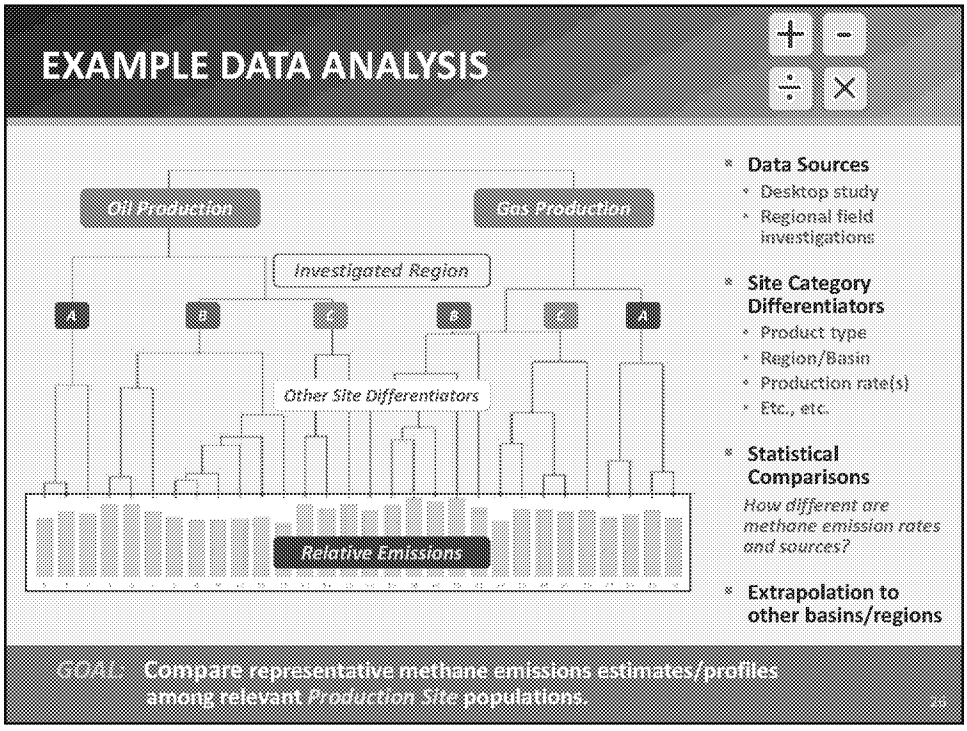

OFF-SITE EMISSION QUANTIFICATION
Atmospheric Sampling
Tracer and OTM33A techniques, with geo-location and concurrent wind speed/direction
Instruments in van
Picarro G2210-I
CH_4, C_2H_6, H_2O
Aerodyne mini-TLDS
CH_4, C_2H_2, N_2O, H_2O
Licor 850A
CO_2, H_2O
Hemispheres GPS
Gill Windsonic
Instruments on-site
Tracer gas mass flow controllers
Weather stations at tracer gas release points
ENERGY INSTITUTE
COLORADO STATE UNIVERSITY
Van Off-site
Tracer Rig On-site
25

25


EXAMPLE DATA ANALYSIS
Oil Production
Gas Production
Investigated Region
A
B
C
B
C
A
Other Site Differentiators
Relative Emissions
Data Sources
Desktop study
Regional field investigations
Site Category Differentiators
Product type
Region/Basin
Production rate(s)
Etc., etc.
Statistical Comparisons
How different are methane emission rates and sources?
Extrapolation to other basins/regions
GOAL: Compare representative methane emissions estimates/profiles among relevant Production Site populations.

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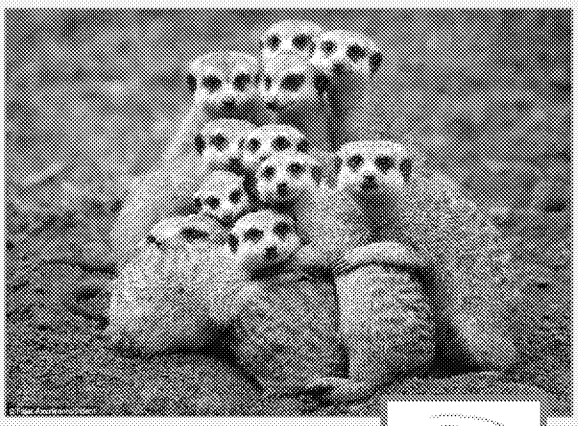
STAKEHOLDER ENGAGEMENT

- Well site data
- Well site access
- Technical advisory
  - Industry TASC
  - General TASC
  - Regional planning committees
- Supplemental funding



Key Point: **Stakeholder involvement is essential to produce defensible results and address multiple concerns.**

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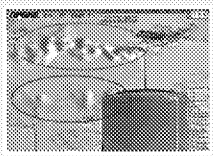
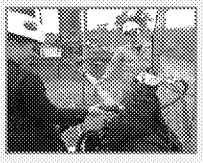
NEXT STEPS

- *August 2019*
  - **Regional field workplan** – Appalachian and Illinois Basins
  - **Site access coordination** – Participating operators
- *September 2019 – March 2020*
  - **Regional field campaigns** *(and workplan amendments, as needed)*
- *May – June 2020*
  - **TASC calls** – Discuss field results, data analyses, and findings





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THANK YOU! QUESTIONS?
Richard L. Bowers, PE, BCEE
512-346-4474
rlbowers@gsi-net.com
Ann P. Smith, PE, BCEE
512-346-4474
apsmith@gsi-net.com
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ATTACHMENT B - Summary of Reviewed Literature

	AUTHOR(s)	TITLE / SOURCE
1	Omara et al. (2016)	**Methane emissions from conventional and unconventional gas production sites in the Marcellus Shale Basin** https://pubs.acs.org/doi/abs/10.1021/acs.est.5b05503
2	Omara et al. (2018)	**Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate** https://pubs.acs.org/doi/pdf/10.1021/acs.est.8b03535
3	Lyon et al (2016)	**Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites** https://pubs.acs.org/doi/pdf/10.1021/acs.est.6b00705
4	Zavala-Ariaza et al. (2015b)	**Reconciling divergent estimates of oil and gas methane emissions** https://www.pnas.org/content/112/51/15597
5	Littlefield et al. (2017)	**Synthesis of recent ground-level methane emission measurements from the U.S. natural gas supply chain** https://www.sciencedirect.com/science/article/pii/S0959652617301166
6	Yacovitch et al. (2015)	**Mobile Laboratory Observations of Methane Emissions in the Barnett Shale Region** https://pubs.acs.org/doi/10.1021/es506352j
7	Rella et al (2015)	**Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique** https://pubs.acs.org/doi/abs/10.1021/acs.est.5b00099
8	Lan et al (2015)	**Characterizing Fugitive Methane Emissions in the Barnett Shale Area Using a Mobile Laboratory** https://pubs.acs.org/doi/abs/10.1021/es5063055
9	Stephenson et al. (2011)	**Relative GHG Emissions Conventional and Shale Gas Production** https://pubs.acs.org/doi/10.1021/es2024115
10	Allen et al. (2013)	**Measurements of methane emissions at natural gas production sites in the United States** https://www.pnas.org/content/early/2013/09/10/1304880110
11	Zaimes et al. (2019)	**Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading** https://pubs.acs.org/doi/pdf/10.1021/acs.est.8b05546
12	Vaughn et al. (2018)	**Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region** https://www.pnas.org/content/115/46/11712
13	Bell et al. (2017)	**Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads** https://www.elementascience.org/articles/10.1525/elementa.266/
14	Peischl et al. (2018)	**Quantifying Methane and Ethane Emissions to the Atmosphere from Central and Western U.S. Oil and Natural Gas Production Regions** https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2018JD028622

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ATTACHMENT B - Summary of Reviewed Literature

	AUTHOR(s)	TITLE / SOURCE
15	Peischl et al. (2016)	**Quantifying atmospheric methane emissions from oil and natural gas production in the Bakken shale region of North Dakota** https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2015JD024631
16	Peischl et al. (2015)	**Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions** https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2014JD022697
17	Alvarez et al. (2018)	**Assessment of methane emissions from the U.S. oil and gas supply chain** https://science.sciencemag.org/content/361/6398/186
18	Lavoie et al. (2017)	**Spatiotemporal Variability of Methane Emissions at Oil and Natural Gas Operations in the Eagle Ford Basin** https://pubs.acs.org/doi/10.1021/acs.est.7b00814
19	Brandt et al. (2016a)	**Methane Leaks from Natural Has Systems Follow Extreme Distributions** https://pubs.acs.org/doi/10.1021/acs.est.6b04303
20	Brantley et al. (2015)	**Assessment of VOC and HAP emissions from O&G well pads using mobile remote and on-site direct measurements** https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryId=311218&Lab=NRMRL
21	Zavala-Ariaza et al. (2015a)	**Toward a functional definition of methane super-emitters** https://pubs.acs.org/doi/abs/10.1021/acs.est.5b00133
22	Zavala-Ariaza et al. (2017)	**Super-emitters in natural gas infrastructure are caused by abnormal process conditions** https://www.nature.com/articles/ncomms14012
23	Zavala-Ariaza et al. (2018)	**Methane emissions from oil and gas production sites in Alberta, Canada** https://www.elementascience.org/articles/10.1525/elementa.284/
24	TAMEST (2017)	**Environmental and Community Impacts of Shale Development in Texas** https://tamest.org/wp-content/uploads/2017/07/Final-Shale-Task-Force-Report.pdf
25	SOGNEX (2015)	**Studying the Atmospheric Effects of Changing Energy Use in the U.S. at the Nexus of Air Quality and Climate Change** https://www.esrl.noaa.gov/csd/projects/songnex/whitepaper.pdf
26	Allen (2014)	**Atmospheric emissions and air quality impacts from natural gas production and use** https://www.annualreviews.org/doi/abs/10.1146/annurev-chembioeng-060713-035938
27	Allen et al. (2014a)	**Methane emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers** https://pubs.acs.org/doi/10.1021/es5040156
28	Allen et al. (2014b)	**Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings** https://doi.org/10.1021/es504016r

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	AUTHOR(s)	TITLE / SOURCE
29	Brandt et al. (2016)	**Energy Intensity and Greenhouse Gas Emissions from Tight Oil Production in the Bakken Formation** https://pubs.acs.org/doi/abs/10.1021/acs.energyfuels.6b01907
30	Brandt et al. (2018)	**Climate-wise choices in a world of oil abundance** https://iopscience.iop.org/article/10.1088/1748-9326/aaae76
31	Mehrotra et al. (2017)	**Airborne Methane Emission Measurements for Selected Oil and Gas Facilities Across California** https://pubs.acs.org/doi/abs/10.1021/acs.est.7b03254
32	Goetz et al. (2015)	**Atmospheric Emission Characterization of Marcellus Shale Natural Gas Development Sites** https://pubs.acs.org/doi/abs/10.1021/acs.est.5b00452
33	Howard (2015)	**University of Texas study underestimates national methane emissions at natural gas production sites due to instrument sensor failure** https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.81
34	Howard et al. (2015)	**Sensor transition failure in the high flow sampler: Implications for methane emission inventories of natural gas infrastructure** https://www.ncbi.nlm.nih.gov/pubmed/26079559
35	OGCI (2018)	**2018 Oil and Gas Climate Initiative Report** https://oilandgasclimateinitiative.com/wp-content/uploads/2018/09/OGCI_Report_2018.pdf
36	Yeh et al. (2017)	**Energy Intensity and Greenhouse Gas Emissions from Oil Production in the Eagle Ford Shale** https://pubs.acs.org/doi/abs/10.1021/acs.energyfuels.6b02916
37	Harriss et al. (2015)	**Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas** https://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305
38	OilPrice.com	**The Gas Flaring Crisis in the U.S. Oil Patch** https://oilprice.com/Energy/Natural-Gas/The-Gas-Flaring-Crisis-In-The-US-Oil-Patch.html
39	EPA (2018)	**Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017** https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf
40	83 Federal Register 52,056 (Oct. 15, 2018)	**Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration** https://www.federalregister.gov/documents/2018/10/15/2018-20961/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources
41	IOGCC (2016)	**Marginal Wells: Fuel for Economic Growth** http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/Marginal%20Well%202016%20-%20FINAL.pdf
42	Bluestein et al. (2016)	**Methane Emissions from the Oil and Gas Industry: "Making Sense of the Noise."** https://www.icf.com/resources/white-papers/2015/methane-emissions-from-the-oil-and-gas-industry

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	AUTHOR(s)	TITLE / SOURCE
43	Brandt et al. (2014)	**Methane Leaks from North American Natural Gas Systems** https://science.sciencemag.org/content/343/6172/733
44	Pring et al. (2010)	**Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions** https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY1026-20101124-ergi-oilGasEmissionsInventory.pdf
45	ERG (2011)	**City of Fort Worth Natural Gas Air Quality Study** http://fortworthtexas.gov/gaswells/air-quality-study/final/

Message

From: Gilbreath, Jan [Gilbreath.Jan@epa.gov]
Sent: 7/2/2018 1:53:20 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]
Subject: Updated one pager
Attachments: oil and gas methane timeline..docx

I've updated my one pager based on Beth's comments. Please look at how I have characterized the discussion of Options 2 and 3 for the technical package and tell me if it's okay. I want to give this to Brittany as soon as I can because I don't know when the politicals are going to talk to OMB again.

Jan

Oil and Gas Methane Reconsideration Timeline

April 4, 2017:

EPA announced a review of the 2016 Oil and Gas New Source Performance Standards (NSPS) for the oil and gas industry, which was finalized in 2016. The Agency stated that, if appropriate, it would initiate reconsideration proceedings to suspend, revise or rescind this rule.

May 26, 2017:

EPA issued a 90-day stay of the fugitive emissions, pneumatic pumps, and professional engineer certification requirements of the 2016 NSPS to give the Agency time to work through a reconsideration process.

Only July 3, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's 90-day stay.

June 16, 2017:

EPA proposed a two-year stay of the 2016 rule's fugitive emissions requirements, well site pneumatic pump standards, and requirements that closed vent systems be certified by a professional engineer while the agency reconsidered issues associated with these requirements.

November 1, 2017:

EPA issued two notices of data availability related to the agency's proposed stays of certain requirements in the 2016 NSPS for the oil and natural gas industry. The notices sought comment on some of the issues and suggestions stakeholders identified after the agency proposed a two-year stay and a three-month stay of certain requirements in the 2016 rule.

The information provided in the NODAs fell into two categories:

- challenges to implementing the requirements in the 2016 rule that would be covered by proposed stays; and
- the agency's legal authority to issue a stay.

EPA also provided an updated analysis of cost savings, forgone benefits and net benefits of the proposed two-year stay.

March 1, 2018:

EPA announced amendments to two narrow provisions of the 2016 NSPS for the oil and natural gas industry in response to comments the agency received on proposed stays of the rule and on subsequent Notices of Data Availability. The amendments addressed two of the fugitive emissions requirements in the 2016 rule that posed significant and immediate compliance concerns--a requirement that leaking components be repaired during unplanned or emergency shutdowns; and the monitoring survey requirements for well sites located on the Alaskan North Slope.

April 27, 2018:

EPA submitted an oil and gas technical reconsideration package to OMB that proposes amendments to the 2016 NSPS on pneumatic pump requirements, fugitive emissions requirements at well sites and compressor stations; professional engineering certification for closed vent system (CVS) design and pneumatic pump technical infeasibility; alternative means of emissions limitations (AMEL); well completion requirements; requirements at onshore natural gas processing plants; and that offers a definition of a greenfield site.

Ex. 5 Deliberative Process (DP)

July 2018

Ex. 5 Deliberative Process (DP)

Message

From: Beeler, Cindy [Beeler.Cindy@epa.gov]
Sent: 7/3/2018 8:53:37 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]; Witt, Jon [Witt.Jon@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]; Davis, Alison [Davis.Alison@epa.gov]; Branning, Amy [Branning.Amy@epa.gov]
Subject: Western Governors Assc Resolution incl. O&G Methane Emissions
Attachments: WGA_PR_2018-05_Air_Quality.pdf

FYI – Attached is the Western Governors Association Air Quality and Methane Emissions Resolution adopted last week 6/27/18.

Methane Emissions

22. Oil and gas operations are an important economic activity in the West, and western states regulate these operations through comprehensive programs. Methane is also a potent greenhouse gas emitted from a variety of sources, including oil and gas operations, coal mines, landfills, agriculture, and natural sources. There are environmental and economic benefits of reducing methane emissions and opportunities for the beneficial use of this natural resource.

23. Many western states – in cooperation with industry in those states – have already implemented regulatory strategies that reduce methane emissions from oil and gas operations, while expanding the use and sale of methane.

24. In any federal methane regulation, federal agencies should: (1) ensure that the capture, commoditization, and sale of methane is promoted; (2) give states the flexibility to integrate a variety of technologies and tools to achieve methane emission reduction standards; (3) recognize methane emissions reductions that result from existing state regulation of volatile organic compounds; and (4) work with states to ensure the consistent use of a single, clear method of quantifying methane emissions.

Cindy Beeler
US EPA Region 8
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Policy Resolution 2018-05

Air Quality and Methane Emissions Regulation

A. BACKGROUND

1. Clean air is essential for strong communities and superior quality of life. Air quality is influenced by both human activities and natural phenomena. Baseline air quality and the sources of impacts to that baseline differ based on local industry, geography, population, meteorology, and other state or regional conditions.

2. In the West, high elevations, extreme variations in topography, vast landscapes, and vacillating weather patterns influence air quality. The West is also disproportionately impacted by wildfires, high wind dust events, and international transport of pollutants. Pollutant sources, methods of dispersion, and types of impacted areas in the West are very different from those in the eastern United States.

3. The Clean Air Act (CAA) establishes a regulatory structure for controlling, monitoring, and improving air quality through a system of cooperative federalism in which states and the Environmental Protection Agency (EPA) work together as co-regulators and as partners in air quality management.

4. States have the authority to manage air quality within their borders. Many western states have assumed primary responsibility for the implementation and enforcement of the CAA, subject to the minimum requirements established by EPA, through approved State Implementation Plans (SIPs).

5. The CAA obligates all states to develop SIPs to attain and maintain National Ambient Air Quality Standards (NAAQS) for criteria pollutants. The General Conformity Rule requires federal agencies to work with states in nonattainment and maintenance areas to ensure that federal actions conform to any applicable SIP.

6. Air quality in the West has benefited from significant emissions reductions over the last 20 years. However, the number and types of remaining emissions sources controllable by states are somewhat limited. The CAA directs states, pursuant to their SIPs or FIPs, to reduce criteria pollutant emissions from sources that states can control, not natural or international sources. It also precludes states (except California) from establishing emissions standards for mobile sources.

B. GOVERNORS' POLICY STATEMENT

Co-Regulation

1. Western Governors value the cooperative federalism in air quality management and believe its application can and should be improved. In some cases, federal agencies disregard state expertise and authority over air quality or do not solicit valuable input from states. Limited availability of financial resources exacerbates these tensions.

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2. EPA should recognize state authority under the CAA and accord states sufficient flexibility to create air quality and emissions programs tailored to individual state needs, industries, and economies. In reviewing state plans, EPA should focus on the circumstances facing the individual state. EPA should not reject reasonable state policy choices based solely on concerns that such choices might not be appropriate for all states.

3. Federal agencies should communicate, consult, and engage with Governors and state air quality agencies as co-regulators. For example, in the Prevention of Significant Deterioration (PSD) program, EPA should work with states to clarify responsibilities and procedures to improve coordination and consultation among state agencies, EPA, and federal land managers, as well as develop guidelines and tools for the program.

4. State CAA programs require financial and technical support from EPA and Congress. EPA must have sufficient resources to perform the research necessary to develop tools, templates, and guidance for states to implement effective and efficient air programs.

5. EPA rules and guidance should be clear, timely, and supported by current science and data. EPA should consult with states throughout the drafting process before a potential rule or guidance becomes public. EPA should also provide states with timely implementation guidance when new and revised regulations or standards are published.

6. States require certainty and consistency from Congress and EPA to implement their CAA programs. Congress and EPA should maintain the deadline for the New Source Performance Standard (NSPS) for wood stoves and its regulations addressing mobile sources. States are depending on these reductions to comply with their SIPs.

7. Under current rules and guidance, states must monitor NAAQS throughout a 20-year maintenance period, even when there is no threat of an exceedance and/or the standard has been superseded by a more stringent or different standard. States should be allowed to reduce monitoring in maintenance areas that have appropriately demonstrated air quality in the area is below the NAAQS. This allowance will free resources to address pollutants that remain a concern.

Ozone

8. Uncontrollable events and conditions (such as wildfire, lightning, biogenic emissions, stratospheric ozone intrusion, and transported ozone from international and interstate sources) result in elevated levels of background ozone. Western Governors have significant concerns about the lack of CAA tools available to account for ozone exceedances resulting from factors outside state control.

9. The West needs additional and ongoing research on background, interstate, and international ozone. This research should be transparent, comprehensive, and coordinated with state air quality agencies and regional organizations. With this new information, EPA should reconsider the one percent threshold for significant contribution for interstate ozone transport obligations.

10. Congress should provide dedicated funding for analysis of background and transported ozone in the West, as it has historically done for the eastern United States.

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Exceptional Events

11. Exceptional event demonstrations are resource-intensive, costly, and place a significant burden on strained state resources, especially when EPA does not review or approve these state submissions in a timely manner. EPA should streamline the process for exceptional event demonstrations, provide additional technical tools for states, and allocate resources to review state demonstrations.

12. Western Governors believe the states and EPA would benefit from the following approaches to exceptional events demonstrations: (1) aggregation of multiple factors contributing to air quality to prove a single exceptional event exceedance demonstration; (2) regional exceptional event demonstrations; and (3) reference to previously submitted and approved exceptional events demonstrations for repeated event types.

13. EPA should: create an online submission system for exceptional event demonstrations; develop a database with information on air quality impacts in the West (with special emphasis on wildfires); and provide a clearinghouse with tools that states can use for exceptional events demonstrations.

Regional Haze

14. Good visibility in the 118 western Regional Haze Program Class 1 Areas, which include many of the crown jewels of the West's national parks and wilderness areas, positively impacts western states' economies. It is important to address mobile and international emissions sources beyond states' control in the context of western states' regional haze planning processes.

15. The profound impacts of fire and smoke on visibility at Class I areas in the West should be recognized in the Regional Haze Guidance and Rule.

16. EPA provided Draft Regional Haze Guidance for the second implementation period of the Rule in July 2016 but has not finalized this guidance. States are beginning work on their SIPs for the second implementation period. Final Regional Haze Guidance is necessary to reduce uncertainty for states as they formulate their SIPs.

17. Given the importance of improved visibility in the West, EPA should provide funding and resources to states throughout the planning and implementation process.

Wildfire and Prescribed Fire

18. More frequent and intense wildfires are steadily reducing the West's gains in air quality improvement. Smoke from wildfires can cause air quality to exceed the NAAQS for particulate matter and ozone, impacting public health, safety and transportation. Prescribed fire, which is managed according to state SIPs and smoke management programs, can reduce these impacts, but is currently underutilized.

19. Western Governors support the use of prescribed fire to reduce the air quality impacts from uncharacteristic wildfire in the West. Federal and state land managers should have the

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ability to use prescribed fires when weather and site conditions are appropriate and air quality impacts are minimized.

20. Prescribed fire practices should include smoke management planning coordinated between state land managers, state air agencies, state health departments, EPA, other federal agencies, and federal land managers. State or regional prescribed fire councils can help facilitate this coordination.

21. Western Governors call on EPA and federal land managers to improve existing tools and create additional tools for states to encourage prescribed fire. These should include simplified exceptional events guidance for prescribed fire, and tools to address the air quality impacts from wildfire in the West.

Methane Emissions

22. Oil and gas operations are an important economic activity in the West, and western states regulate these operations through comprehensive programs. Methane is also a potent greenhouse gas emitted from a variety of sources, including oil and gas operations, coal mines, landfills, agriculture, and natural sources. There are environmental and economic benefits of reducing methane emissions and opportunities for the beneficial use of this natural resource.

23. Many western states – in cooperation with industry in those states – have already implemented regulatory strategies that reduce methane emissions from oil and gas operations, while expanding the use and sale of methane.

24. In any federal methane regulation, federal agencies should: (1) ensure that the capture, commoditization, and sale of methane is promoted; (2) give states the flexibility to integrate a variety of technologies and tools to achieve methane emission reduction standards; (3) recognize methane emissions reductions that result from existing state regulation of volatile organic compounds; and (4) work with states to ensure the consistent use of a single, clear method of quantifying methane emissions.

C. GOVERNORS' MANAGEMENT DIRECTIVE

1. The Governors direct WGA staff to work with congressional committees of jurisdiction, the Executive Branch, and other entities, where appropriate, to achieve the objectives of this resolution.

2. Furthermore, the Governors direct WGA staff to consult with the Staff Advisory Council regarding its efforts to realize the objectives of this resolution and to keep the Governors apprised of its progress in this regard.

Western Governors enact new policy resolutions and amend existing resolutions on a bi-annual basis. Please consult www.westgov.org/policies for the most current copy of a resolution and a list of all current WGA policy resolutions.

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Message

From: Dewees, Jason [Dewees.Jason@epa.gov]
Sent: 9/5/2017 3:02:33 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]; Witosky, Matthew [Witosky.Matthew@epa.gov]; Garwood, Gerri [Garwood.Gerri@epa.gov]
Subject: FW: Internal Draft-Evaluation of Innovative Methane Technologies Tech Reg Document-Edits/Comments Due Sept 13
Attachments: ITRC METHANE TECH REG DOCUMENT_Internal_Draft_8_22_2017_Posted.pdf

Importance: High

All,

Here is the first internal "final" draft of the ITRC document. I haven't looked at the sections outside of my focus (technology and evaluations) for a while, which were VERY lacking a couple weeks ago.

And despite the 100 plus pages having nothing to do with it. This document is supposed to be focused at the evaluation of technology, which it doesn't even really touch on.

EPA does get a formal shot (scheduled for 1/2/18 with comments due 2/23) at this document in the future, but I figured that I would let people see where it stands now. In theory, the document is done early next year. If anyone has some overarching comments (before Sept 19th), I can certainly pass those along.

And just as a FYI – I can see APRA-e pulling the funding from it the next couple months ending the project.

Jason

From: Susan Schow [mailto:Ex. 6 Personal Privacy (PP)@comcast.net]
Sent: Monday, August 21, 2017 3:04 PM
To: cesar.alfaro@bsee.gov; Barbery, Andrea <Barbery.Andrea@epa.gov>; Beeler, Cindy <Beeler.Cindy@epa.gov>; jbinder@burnsmcd.com; dburge@environcorp.com; ncezar@ndce.ca; lance.e.christensen@jpl.nasa.gov; cclavin@ida.org; jcollins3@mt.gov; cramer@adeq.state.ar.us; bdeering@gesonline.com; Ex. 6 Personal Privacy (PP)@gmail.com; Dewees, Jason <Dewees.Jason@epa.gov>; ldorman@pa.gov; roopa.ganapathy@canada.ca; ag5@azdeq.gov; nathaniel.gorence@hq.doe.gov; matt.harrison@aecom.com; jorn.herner@arb.ca.gov; kaylie.holland@alaska.gov; Ex. 6 Personal Privacy (PP)@gmail.com; james jarrett <james.f.jarrett@wv.gov>; kelly.kaletsky@epa.ohio.gov; hisanori.kawashima@konicaminolta.com; mkhan@desu.edu; christopher.konek@hq.doe.gov; kitty.kong@chevron.com; kopero@battelle.org; edward.long1@navy.mil; dlyon@edf.org; angela.marconi@state.de.us; Ex. 6 Personal Privacy (PP)@gmail.com; jmcgreevy@cecinc.com; amckittr@ida.org; adam.miller@nd.gov; john.miranda@hl.konicaminolta.us; Ex. 6 Personal Privacy (PP)@comcast.net; anowlan@edf.org; craig.oneill@flir.com; ona.papageorgiou@dec.ny.gov; mpatil@langan.com; sreinis@langan.com; sdrichardson@gsi-net.com; j.rutherford@heathus.com; escheehl@arb.ca.gov; schow29@comcast.net; sanjay.shah@dep.nj.gov; Ex. 6 Personal Privacy (PP)@earthlink.net; nsihota@chevron.com; kevin.speicher@dps.ny.gov; dspicuzza@woodardcurran.com; petestrauss1@comcast.net; Ex. 6 Personal Privacy (PP)@gsi-net.com; Ex. 6 Personal Privacy (PP)@gmail.com; Ex. 6 Personal Privacy (PP)@live.com <timothya.taylor@state.co.us>; ouppal@langan.com; laura@kairosaerospace.com; changyong.zhang@exxonmobil.com
Cc: 'Patricia Reyes' <preyes@ecos.org>; Carolyn Sistare <csistare@ecos.org>
Subject: Internal Draft-Evaluation of Innovative Methane Technologies Tech Reg Document-Edits/Comments Due Sept 13
Importance: High

Attention ITRC Methane Team Members:

Thanks to your relentless efforts, the Internal Draft version of the *Evaluation of Innovative Methane Technologies* Tech Reg document is ready for sharing and reviewing (almost as exciting as an eclipse!)

It is posted to the Methane Team SharePoint folder as a Word (.doc) document at:
https://itrcweb.sharepoint.com/_layouts/15/guestaccess.aspx?docid=18c74994049e24b5283dab65438a8b0c8&authkey=AfwAEz0a3krtuvwucNEmliE

It is attached to this email and posted as an Adobe Acrobat (.pdf) file at SharePoint this link:
https://itrcweb.sharepoint.com/_layouts/15/guestaccess.aspx?docid=10c2b57d4004c473e97e6fba9abbcdea0&authkey=AYCEh34aW314Chdx1afqqG0

Additionally – you will find it posted as a Word doc and as an Adobe Acrobat file at the ITRC Methane Team webpage at:
http://www.itrcweb.org/Team/Private?teamID=77

See under the "Document Drafts" folder.

I incorporated all edits but some comments that were not easily resolvable have been removed (I did not want to leave the individual's comments with their names in the draft version). If still relevant, please comment on these again and we will address at the Sept meeting.

You will note that some editing comments, highlights, and reminders were left in the text so we will remember what still needs our attention. We placed the Case Study Summaries in Appendix A and will, of course, be linking to the most relevant of these within the other sections of the text.

Please review the draft document and submit revisions, edits and comments to Susan by **Sept 13th**. This gives me one week to compile for review together at the Sept 20 meeting.

Please be thinking of where you would like to link to specific Case Study summaries within the document as you review and also how to best make this an internet-based document.

If you edit directly in the Word document, please save your new version to the SharePoint or Team webpage with the date and your inititals and send me an email to let me know you have revised.

If you are unable to edit and post via SharePoint coordinate with me carefully so we do not write over each other's edits. Please keep me in the loop with all your revisions or changes.

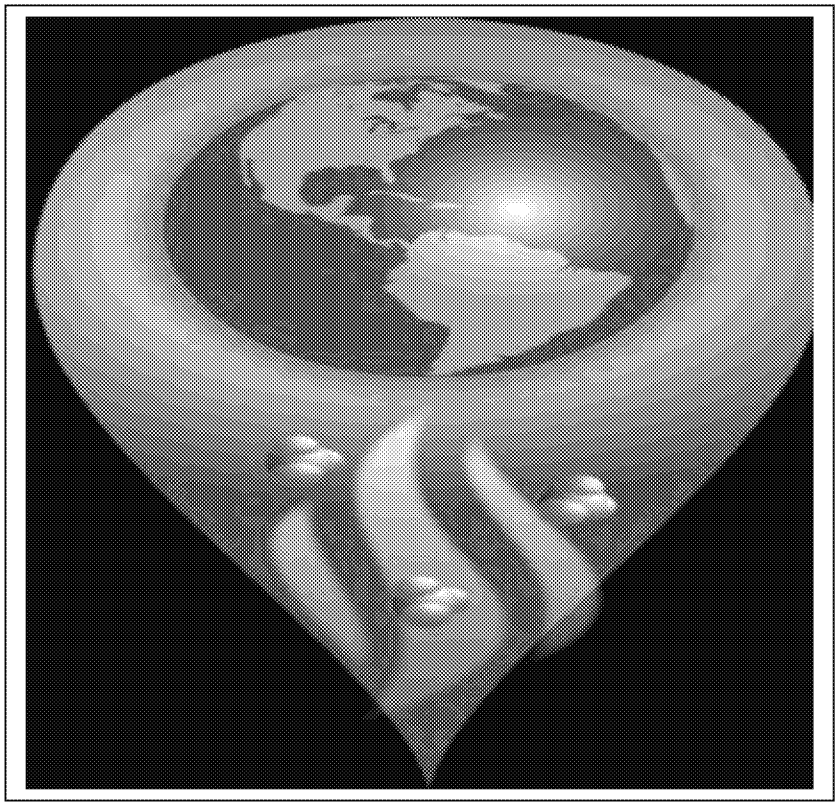
The document is very comprehensive and we are so proud of the great work you have done! Pat yourselves on the backs and then -- get started reviewing the document for the Sept 13th due date!

Thank you,
Susan

Susan Schow, MPH
Ex. 6 Personal Privacy (PP) @comcast.net
207-841-0534

Technical/Regulatory Guidance

Draft
Evaluation of Innovative Methane Detection Technologies



Internal Draft
August 22, 2017

Prepared by

The Interstate Technology & Regulatory Council
Evaluation of Innovative Methane Detection Technologies Team
In Partnership with DOE-ARPA-E

ABOUT ITRC

The Interstate Technology and Regulatory Council (ITRC) is a public-private coalition working to reduce barriers to the use of innovative environmental technologies and approaches so that compliance costs are reduced and cleanup efficacy is maximized. ITRC produces documents and training that broaden and deepen technical knowledge and expedite quality regulatory decision making while protecting human health and the environment. With private and public sector members from all 50 states and the District of Columbia, ITRC truly provides a national perspective. More information on ITRC is available at www.itrcweb.org. ITRC is a program of the Environmental Research Institute of the States (ERIS), a 501(c)(3) organization incorporated in the District of Columbia and managed by the Environmental Council of the States (ECOS). ECOS is the national, nonprofit, nonpartisan association representing the state and territorial environmental commissioners. Its mission is to serve as a champion for states; to provide a clearinghouse of information for state environmental commissioners; to promote coordination in environmental management; and to articulate state positions on environmental issues to Congress, federal agencies, and the public.

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ACRONYM-#

Evaluation of Innovative Methane Detection Technologies

Internal Draft

August 2017

Prepared by

The Interstate Technology & Regulatory Council

Evaluation of Innovative Methane Detection Technologies

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ACKNOWLEDGMENTS

The members of the Interstate Technology & Regulatory Council (ITRC) Evaluation of Innovative Methane Detection Technologies Team wish to acknowledge the individuals, organizations, and agencies that contributed to this technology and regulatory document.

As part of the broader ITRC effort, the Evaluation of Innovative Methane Detection Technologies effort is funded primarily by the U.S. Department of Energy.

The work team also wishes to recognize the efforts of the following individuals:

-###-

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EXECUTIVE SUMMARY

[Brief executive summary to provide an overview of the work product to policy makers, decision makers, and other document users. When appropriate, the Executive Summary may also provide a broad overview of the team. The executive summary stands alone; it does not reference other parts of the document. Acronyms are not used if the term is not repeated within this summary.]

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EVALUATION OF INNOVATIVE METHANE DETECTION TECHNOLOGIES

1 INTRODUCTION

Natural gas was originally seen as a byproduct of producing oil and was burned off at the oil field production site. As markets developed for natural gas, keeping the gas in the production system became important, since gas was then a saleable product. More recently, methane – the primary component of natural gas – has been identified as a potent greenhouse gas, and various national and international efforts have been launched to quantify and mitigate methane emissions.

ALISO CANYON LEAK

On October 23rd, 2015 the largest known release of methane in US history started when a well in the Aliso Canyon Natural Gas Storage facility in Los Angeles ruptured. 8,000 residents fled the nearby Porter Ranch community due to the odor, complaints of headaches, nausea, nosebleeds, irritation of nose and throat and concern for their health. Approximately 109,000 metric tons of methane was released before the leak was plugged almost four months later. The value of the leaked natural gas is approximately $17 million, but as of the end of 2016 the total cost of the leak had mounted to $780 million to cover costs associated with the resident relocation program, efforts to stop the leak, settlements, and litigation. Southern California Gas, the owner of the facility, suggested that the cost "may rise significantly" as more information become available.

Image of the leaking wellhead, referred to as SS25 on Dec 9, 2015. An oily mist was emitted alongside the natural gas making the nearby hillside black and depositing oily droplets in the nearby community.

Early leak detection methods were simple "audio, visual, and olfactory" (AVO) techniques, wherein an operator of natural gas systems would seek to detect a leak by human observation whenever near their equipment. However, current technologies incorporate sophisticated sensors and take advantage of a variety of mobile platforms. The use of better technologies for detection will lead to reduced losses of product and emissions that lead to both climate change and poor air quality.

Although much attention has been paid to methane as a greenhouse gas, it also poses other risks. Under the right conditions, methane is explosive, thus posing a physical hazard to people and structures, ranging from industrial facilities to apartment buildings and single family homes. [Cite: CityLab_James_West_How_Dangerous _Are_The_Gas_Pipes_Under_Your_City article].

Furthermore, natural gas is a valuable resource; thus, emissions – whether accidental or intentional – represent lost revenue. It was recently estimated by EPA in their April 2017 GHG Inventory that approximately 0.47 trillion cubic feet of natural gas is inadvertently released to the atmosphere from oil and gas facilities, representing $1.4 billion of losses to the industry, assuming a unit cost of $3 per thousand cubic feet (Mcf). [Reference EPA 2017 GHG Inventory – released 4/14/2017]. The U.S. oil and gas industry's methane emissions are

estimated to be equivalent to the household natural gas usage of over 6 million homes, assuming 74 Mcf of gas is used per household per year. [Trends in U.S. Residential Natural Gas Consumption, Office of the Energy Information Administration, Office of Oil and Gas, June 2010, https://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf)]

In another example, the natural gas distribution pipes of urban New Jersey have long been in need of repair. The state's largest utility, Public Service and Enterprise Group (PSE&G), wanted to replace them. PSE&G owns 4,330 miles of them; replacing it was estimated to exceed at $6 billion (insert reference). The state's Board of Public Utilities, which regulates how much money PSE&G can raise from its customers and how it can spend it, had earlier rejected a request from the utility to raise $1.6 billion for 800 miles of new pipeline (or an average of $2 million per mile). But in 2014, the Environmental Defense Fund (EDF) approached the utility with a solution. Using new technology that can trace methane emissions back to their sources with great precision, researchers could prioritize the highest-risk pipes. After the results of the monitoring effort were in, the utility narrowed its request to 510 miles of pipeline replacement, at a cost savings of $905 million over three years (From 04 APR 2016: With New Tools, A Focus On Urban Methane Leaks) http://e360.yale.edu/features/with_new_tools_focus_on_urban_methane_leaks

East Harlem Apartment Building Explosion

On March 12, 2014, two adjacent five-story multi-use buildings were destroyed by a natural gas explosion and subsequent structural fire on Park Street, East Harlem, New York City. This incident resulted in eight fatalities, 48 reported injuries, and displaced more than 100 families from their homes. Information gathered during the investigation suggests that intermittent natural gas odors were detected within the incident buildings, an adjacent building, and nearby outside areas in the days preceding the incident. Following this incident, local distribution company experienced a significant increase in gas odor related call volume. Immediately after this tragedy, the utility began monthly leakage surveys of its distribution system to detect natural gas leaks (which continue today), plotted active gas leaks on-line (updated daily), and has decreased its leak backlog by over 70% since 2013. In addition, the New York State Department of Public Service is requiring this and other local gas distribution companies to develop pilot programs to deploy residential methane detectors to detect natural gas leakage within buildings.

Lastly, the methane and VOCs present in natural gas are frequently associated with other negative impacts to air quality, such formation of ground level ozone, leading to photochemical smog formation, and formation of secondary organic aerosols found in airborne particulate matter.

RECENT RESEARCH RESULTS

Recent studies using ambient measurements suggest methane inventories may underestimate total methane emissions. New oil and gas extraction methods and the existence of "super-emitters", a small fraction of emitter within a source sector that is responsible for a large proportion of total emissions, may play a crucial role in the discrepancy. These studies are also suggesting that high VOC and ozone in otherwise rural areas may be connected to the new oil and gas activities in several western states.

1.1 Purpose of Document

The purpose of this document is to provide an overview of existing and developing technologies as well as guidance regarding performance characteristics and parameters to consider in technology evaluation. This information is intended to enable regulators, facility owners and operators, and other users to evaluate, compare, and select suitable technologies that detect and quantify methane emissions from various segments of the oil and natural gas supply chain

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for compliance with existing and forthcoming methane emission (leak) regulations, monitor inventories, and enhance workforce and public safety.

1.2 Document Scope

- This document is focused primarily on the oil and gas industry the industry with the most urgent need for methane detection technologies due to current regulatory requirements. However, this guidance document will also be useful for other industries, including municipal waste landfills, workforce safety, agriculture (e.g., dairies and feedlots), and others.
- Although the focus of this document is on methane detection technologies, there are regulations that apply to both methane and VOC emissions, therefore the document also discusses VOCs in that context.
- This guidance addresses the regulatory environment pertaining to on-shore methane emission sources. Although off-shore emissions are of equal concern, these facilities are difficult to access (e.g., production platforms) and may be located in marine or sub-marine environments (e.g., platform-to-shore pipelines), which will require a different approach to methane emission detection
- This document encompasses existing and developing technologies, but does not delve into on-going R&D efforts; the technology field is dynamic and rapidly-evolving, and this guidance may require significant updating in a relatively short period of time.
- This document is intended to provide a reasonably comprehensive overview of available methane detection technologies, but not an exhaustive compilation of all technology combinations (e.g., same sensor on different mobile platforms).
- Similarly, this guidance is intended to provide an overview of the current regulatory environment, but does not seek to serve as an exhaustive, all-inclusive reference for methane emissions regulations in all 50 states and federal lands.

1.3 Intended Audience

This document is intended for wide audience and may be used as follows:

- Regulatory, technical staff and managers from local government authorities, state environmental programs, and from Federal environmental, land management and energy programs can use this guidance for the following:
    - To inform their decisions regarding the requirements incorporated into pending or future regulations
    - To revise existing regulations to allow for application of new technologies or existing technologies in new ways
    - As a general reference
- Technology developers and vendors can use this document to inform their research and development efforts
- Oil and gas producers, transmission companies, distribution utilities, municipalities, and large facilities with interest in detecting and managing methane releases can use this guidance to assist in selecting existing or emerging methane detection technologies to address the requirements of existing or pending regulations and as a general reference

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Other audiences may include academics involved in researching, developing or evaluating methane-detection technologies, as well as tribal, environmental, community and other interested stakeholders. This guidance will provide them with a common understanding of available and emerging methane detection technologies, a methodology for assessing the applicability of a given technology for a particular purpose or environment, and of regulator expectations for technology performance.

1.4 Framing the Guidance Document

1.4.1 State Survey for Regulations

A survey of states was made using the ITRC's State Point of Contacts (POC) to collect information on laws, policies, and regulations requiring Leak Detection and Repair (LDAR) or control of methane emissions from the oil and natural gas industries. Thirty-six state POCs responded and of those fourteen reported having relevant regulations in place or under consideration, with six of those requiring both LDAR and control of methane emissions. Most existing regulations rely on EPA Method 21 for leak detection with a few states also allowing the use of infrared cameras.

1.4.2 Industry Concerns (?)

Substantial industry, government, and private funding has spurred the development of many methane detection products and services. From an industry perspective, there are several features that must be considered for technology selection in the methane detection space. First, methane detection strategies need to be designed for the industry segment for which they are intended. For example, vehicle-based platforms that could be deployed to monitor dense, urban natural gas distribution systems are unlikely to be the ideal solution for monitoring geographical dispersed oil and gas production sites. Second, cost effectiveness targets must account for the method under which the industry segment actually recovers cost. For example, the production segment tends to assess leak detection and repair costs in relationship to additional natural gas realizations from the recovered gas while natural gas distributors tend to be assigned defined budgets for repair activities based on collections from local rate payers. Finally, technologies that would like to be considered for large scale deployment must be pilot tested in field locations over an extended period while including advanced analytics to sort out actual detections from measurement noise in order to yield actionable insights.

Furthermore, when regulations are developed, compliance options need to be based on reliable and proven technologies that are focused on quickly finding and fixing the largest emission sources in the most cost effective manner and that limit the overhead spending for compliance demonstration activities. At the same time, it is important that regulations are flexible enough to incorporate innovative technological solutions even if the performance of the technologies is not identical to those on which the regulation was originally based. For example, several states have adopted regulations that require periodic surveys of oil and gas infrastructure with handheld infrared (IR) cameras to locate emission sources. In theory, a technology solution, such as a satellite or very cheap wellpad sensor, could be used to identify larger sources more quickly than periodic manned surveys, which would result in the same or better emission reductions despite having higher detection thresholds.

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1.4.3 Community and Tribal Concerns (?)

These include:

- Stakeholders are concerned that hydro-fracturing increases methane releases, especially when this process is done in areas (primarily for oil) where there is no infrastructure to transport natural gas (thus there is little incentive to collect gas and it is vented or flared).
- Stakeholders are concerned that abandoned wells represent a large problem in terms of safety, land-use and release of methane.
- Stakeholders are especially concerned about pipeline safety, and would like to see any program include technologies that can be used to detect pipeline emissions, especially in more urbanized areas
- Stakeholders are concerned that any program includes evaluation of technologies that will act as early detectors for releases from underground storage facilities.

1.5 Document Organization

This document is organized as follows:

- Section 2 – Characterization: identifies all the known sources of fugitive methane emissions within the oil and gas sector and characterizes the types of emissions and rates that may be expected from each of these sources. Regulatory barriers to the use of various types of methane detection technologies will also be addressed such as various types of overly-restrictive language.
- Section 3 - Regulations: summarizes existing and proposed laws and regulations of local, state, and federal governments that focus on methane leak detection and repair programs for the oil and gas sector. The current needs of existing laws and regulation are also defined, as well as any constraints on the use of technology, legal or otherwise. Regulations in Canada, Europe and other countries are also briefly addressed.
- Section 4 – Technology: discusses the relevant available methane detection technologies and their functional attributes, including whether the data captured is qualitative or quantitative. The type of data is provided as well as whether the measurements are instantaneous or continuous; the relative size of the instrument; the instrument's working distance and how it may be deployed. Lastly, the relative costs and other relevant attributes are noted.
- Section 5 – Evaluation: provides a framework for the evaluation of methane detection technologies, including metrics and procedures for assessing primary and secondary data quality. This section also provides a framework for technology equivalence determination.
- Section 6 – Lessons Learned: identifies and discusses the lessons that have been learned in the generation of this document.

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- Section 7 – Stakeholder Concerns: discusses tribal and stakeholder concerns. In general, stakeholders support programs and regulations that increase the use of and improve detection of methane releases. However, this chapter also identifies concerns that these stakeholders may have.

Appendices are included at the end of the document to present additional information as follows:

- Appendix A: Complete text of case study summaries for use in this document (will also be cited /linked within the other sections of document where relevant).

- Appendix B: North American Industry Classification System (NAICS) and U.S. Standard Industrial Classification (SIC) System Source Classification Code (SCC) List lookup table.

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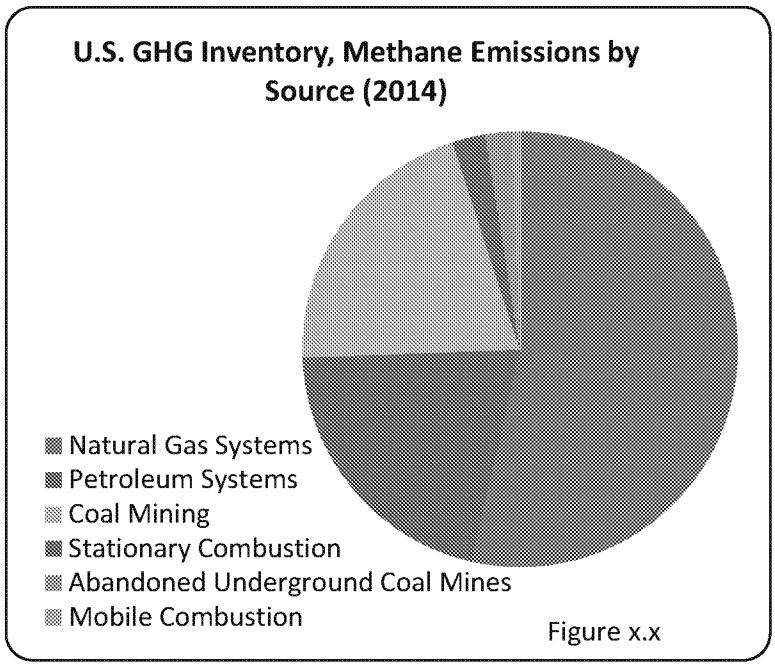
2 CHARACTERIZATION OF EMISSIONS

2.1 Introduction

Methane is the primary component of natural gas in its final form. In addition, methane is released from some oil production processes as an associated gas. Oil and Natural gas systems account for almost 75 percent of methane emissions[1].



There are several areas within the oil and gas sector where methane is emitted either via leaked or planned releases. Here we characterize the oil and gas sector and identify areas where methane releases are known and quantify where data is available.

There are several sources for GHG emissions and each represents the supply chain with slight variations when compared with one another. This document will organize each component of the supply chain according to tables 2.1 and 2.1 in the highlighted rows. Those tables also show the comparison to the GHG inventory and Subpart W organization of the supply chain.

Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Table XX: Comparison of natural gas system characterization of Supbart W, GHG Inventory and this assessment.

[1] U.S. Greenhouse Gas Inventory, 2014.

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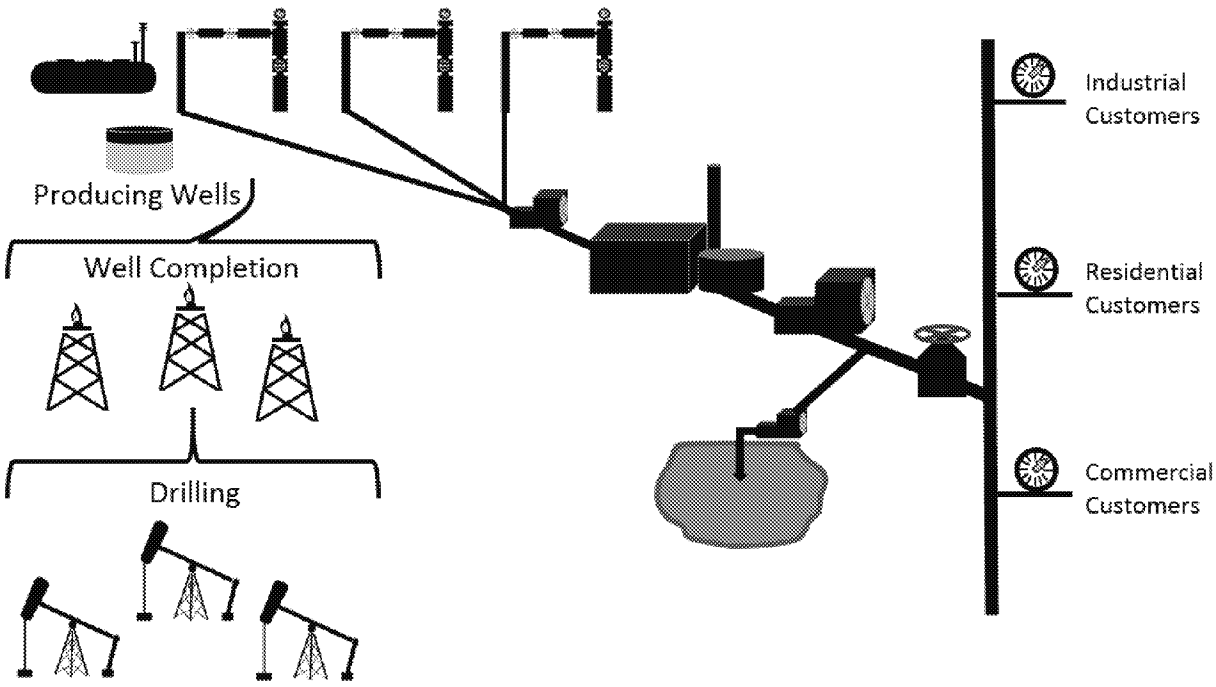
Source (GHG Inventory)	Petroleum Systems (3-37)					
Stage (GHG Inventory)	Production Field Operations (Table A-127)				Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries	
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		

Table XX: Comparison of petroleum system characterization of Supbart W, GHG Inventory and this assessment.



Methane Emissions from Energy							
Gas Source	**1990**	**2005**	**2010**	**2011**	**2012**	**2013**	**2014**
Natural Gas Systems	8,720	7,093	6,647	6,803	6,906	7,023	7,045
Petroleum Systems	1,550	1,953	2,163	2,251	2,335	2,588	2,726

Table XX: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014[2]

[2] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 (https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-chapter-3-energy.pdf)

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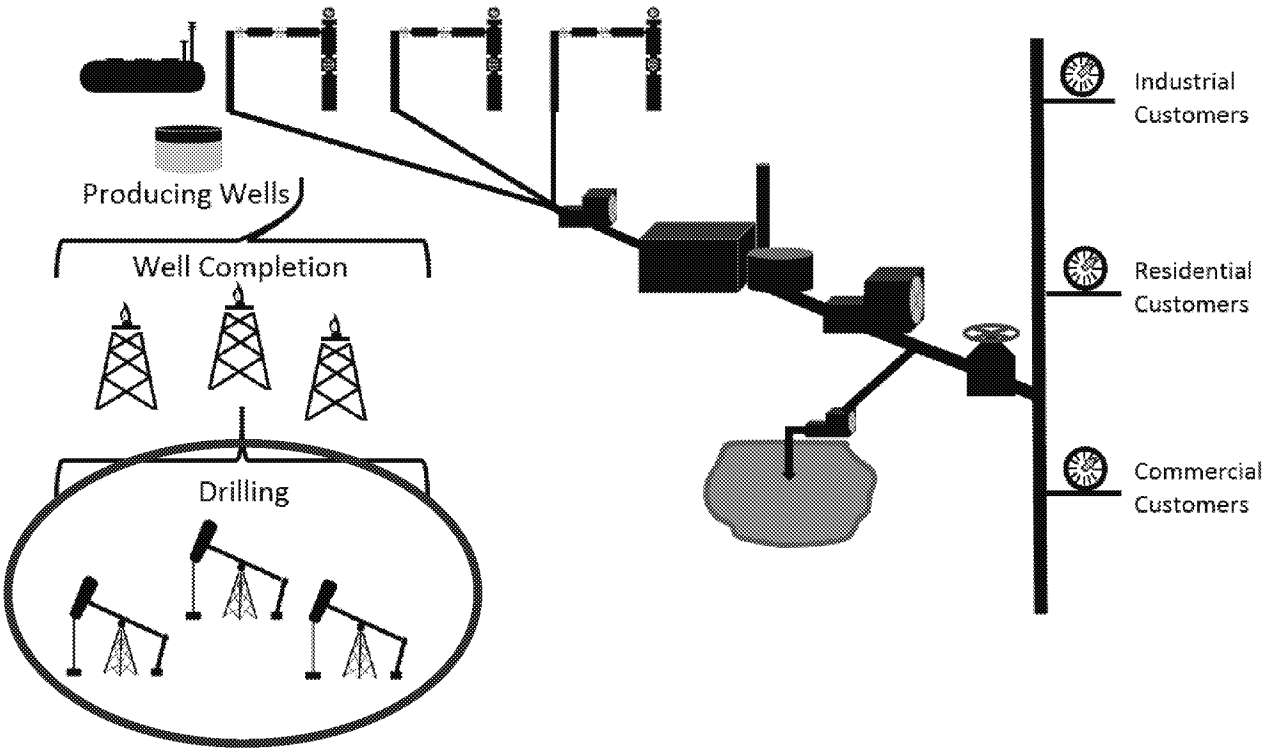
2.2 Field Production

2.2.1 Drilling
2.2.2 Completion
2.2.3 Producing Wells
2.2.4 Gathering Lines
2.2.5 Gathering & Boosting Compressor

2.2.1 Drilling



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Source (GHG Inventory)	Petroleum Systems (3-37)					
Stage (GHG Inventory)	Production Field Operations (Table A-127)				Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries	
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		

2.2.1.1 Drilling stage

Activity Equipment	Emission Factor	Activity Data	Emissions (Bcf/yr)	Emissions (kt/yr)
Well Drilling	NE scfd of CH4/oil well drilled	17,774 No. of oil wells drilled[c,2]	NE	NE

Table XX: Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3 Table A-127, Methodological Descriptions for Additional Source or Sink Categories[3]

Sources For Leaks		
Sealing Element	**"Kick"**	**Mud/Gas Separator**

When drilling, wellheads are designed with a sealing element around the drill pipe to prevent the escape of drilling mud and potentially entrained gas present in the mud and drill cuttings brought to the surface. Wireline wellheads are sealed as well to prevent the escape of brine or other fluid under pressure and potentially gas that migrates into such fluids from the formation. In general, onshore operators in the United States practice overbalanced drilling. This technique uses mud or other fluid pressures above that of the formation pressures to keep formation fluids and gases (where present) from migrating into the wellbore and coming to the surface. There are instances where gas or fluids do escape into the wellbore (referred to as a "kick") that are metered carefully through a mud/gas separator prior to the mud being recirculated back into the well for continued operations. A "kick" is an atypical event and can result in a much more serious well control incident if not properly managed. The gas released from the mud / gas separator is typically either vented to atmosphere or flared. Such events vary in the volume of methane emitted to atmosphere, and in general have been considered more of a safety concern than an environmental issue.

[3] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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2.2.1.2 Drill Rig

Sources For Leaks		
Supply Lines	**Gauges**	**Connectors**

One aspect of the oil production cycle where emissions are not entirely captured are emissions from the drilling and completions phases of well development. New oil drilling rigs are designed to be mobile, and are routinely transported from location to location depending on the availability of work. A rig may stay in one location only long enough to drill a single well, or may be contracted to drill multiple wells on a single location. Depending on the depth of the target formation, it can take less than ten days to drill a single horizontal well with a 10,000 foot lateral (more definition).

In order to drill wells efficiently requires electrical power. Modern horizontal drilling rigs are electrically driven, and routinely operate in areas where electricity for purchase (i.e. pole power) is unavailable. As a result, they are equipped with generator sets to provide the power necessary to operate the drilling rig and associated equipment. In addition, many states require air drilling, also known as pneumatic percussion drilling, or fresh water drilling up until the well penetrates and is cased through the deepest potable freshwater reservoir. For those areas requiring air drilling be employed, additional air compressors are required to supply sufficient volumes of high-pressure air to perform this technique. This point, referred to as the surface casing point, is the largest diameter bore and is cased (i.e. tubular metal casing is inserted into the wellbore) and cemented (using specialty-grade cements) in order to minimized the potential of impacts to potable aquifers.

The fuel for drilling rigs, including the compressors needed for air drilling and pumps to circulate drilling fluids, is primarily diesel fuel. Combustion of diesel fuel does not result in significant emissions of methane. In areas where natural gas is available in sufficient quantities, some operators have mandated that their drilling contractor either co-fire natural gas along with diesel fuel, or utilize generators capable of running solely on natural gas as fuel. Pollutant and GHG emissions from the combustion of natural gas in such generator sets are lower than when firing diesel fuel alone. In addition, limiting the amount of diesel fuel consumed has the downstream impact of requiring less fuel trucks to supply the rig and minimizing the risks inherent to driving. Firing natural gas may also present unique challenges for operators. Given the mobile nature of oil drilling rigs, all lines and connections are necessarily temporary in nature. As a result, it is possible to encounter methane leakage from these supply lines and associated equipment.

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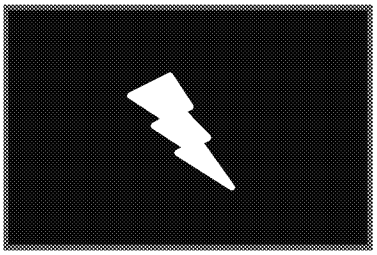
2.2.1.3 Generators

Sources For Leaks		
Temporary Pipe Connectors	**Regulators**	**Valves**
Flanges		**Incomplete Combustion**



Methane emission from electrical generator operation is unlikely, since such engines combust primarily diesel fuel. In instances where dual-fueling or natural gas firing is performed, methane emissions may result from temporary piping connections, regulators, valves, flanges and from incomplete fuel combustion.

2.2.1.4 Mud Tanks

Sources For Leaks		

Drilling mud is either water- or oil-based with additives employed to increase fluid density. In modern oil-based mud, the base is similar to mineral oil. Virgin base oil and drilling mud is stored in tanks prior to use. When in use, the mud is pumped into the drill string which provides fluid cooling to the drilling bit and rotational motion via a "mud motor" to turn the bit. The drilling mud also carries drill cuttings to the surface. Once to the surface, the mud and cuttings are separated as much as possible. The cleaned mud is recirculated back into the mud tanks for reuse, while the cuttings and residual mud are sent off-site for disposal.

Methane emissions from mud tanks are expected since the mud carries the cuttings and hydrocarbons held in those cuttings to the surface. As the cuttings reach the surface, off-gassing of methane (and other air pollutants) would occur. Methane emissions from this process do not appear to be well characterized. One study from 2009 (Emissions from oil and gas production facilities by ERC for TCEQ 582-7-84003) developed an emission factor for such emissions based on a similar study performed for offshore drilling operations.

Most operators require continuous monitoring for hydrogen sulfide (H_2S) around the mud tanks, focusing on where the cuttings are initially removed on the shakers. These areas are

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enclosed during winter operations since they are at times manned and sampled, and there are anecdotal reports of flash fires in these areas like that reported in West Greely, CO on May 8, 2017[4].

2.2.1.5 Wellhead

Activity Equipment	Emission Factor	Activity Data	Emissions (Bcf/yr)	Emissions (kt/yr)
Oil Wells				
Fugitive Emissions			6.479	124.6
Oil Wellheads (heavy crude)	0.13 scfd/well[e,m]	40,227 No. of hvy. Crude wells[d,i,t,1,4]	0.002	0.0*
Oil Wellheads (light crude)	17 scfd/well[e,m]	530,367 No. of lt. crude wells[d,i,t,1,4]	3.219	61.9

Table XX: Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3 Table A-127, Methodological Descriptions for Additional Source or Sink Categories[5]

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)[aa]	Calculated Potential (Mg)[bb]
Gas Wells			
Associated Gas Wells	503,873 wells[a,1,cc]	NA[dd]	0.0
Non-associated Gas Wells (less fractured wells)	205,363 wells[a,1]	7.43-42.49 scfd/well[b]	17,754.5
Gas Wells with Hydraulic Fracturing	250,777 wells[a,1]	7.59-42.49 scfd/well[b]	35,085.1

Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[6]

Sources For Leaks		
Valves	**Tubing**	**Pressure Gauges**

[4] http://www.greeleytribune.com/news/local/worker-suffers-serious-burns-in-tank-fire-at-oil-and-gas-drilling-operation-in-west-greeley/

[5] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

[6] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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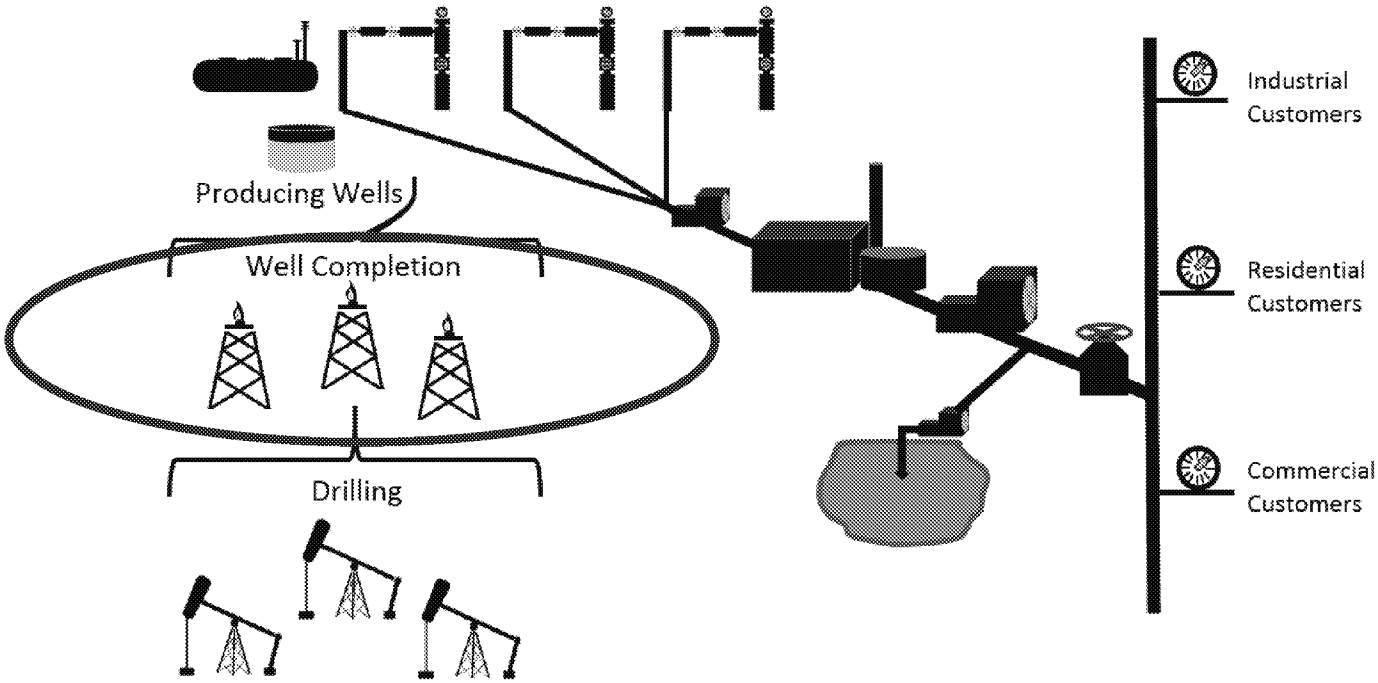
Sensors	**Connectors**	**Valve Packing**

The wellhead is a collection of valves and tubing that are designed to allow fluids and gases from the formation to flow up the well in a safe and controlled manner. As a collection of valves and tubing, along with pressure gauges or sensors, there is an opportunity for fugitive methane emissions from connections and valve packing. Oil wells may accumulate significant liquids over time that are not brought to surface which must be "unloaded" because they can affect well performance. This process is called liquids unloading. Both the fugitive emissions and emissions from liquids unloading are identified under the federal GHG reporting program.

2.2.2 Well completion



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

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Source (GHG Inventory)			Petroleum Systems (3-37)			
Stage (GHG Inventory)		Production Field	Operations (Table A-127)		Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries	
Segment (Subpart W)		Onshore Production		Onshore Gathering & Boosting		

Well completion is the process of making a well ready for production of oil and/or natural gas. This stage includes fracturing the well, the use of green completion components, flaring and the use of condensate/produced water tanks.

Activity Equipment	Emission Factor	Activity Data	Emissions (Bcf/yr)	Emissions (kt/yr)
Vented Emissions				
Stripper wells	2,345 scf/yr of CH4/stripper well[f]	327,674 No. of stripper wells vented[f,d,4]	0.768	14.8
Well Completion Venting	733 scf/completion[h]	15,753 Oil well completions[c,4]	0.012	0.2
Well Workovers	96 scf CH4/workover[i]	67,370 Oil well workovers[g,i,1,4]	0.006	0.1
HF Well Completions, Uncontrolled	351,146 scf/HF completions[s]	17,522 HF oil well completions[t,2]	6.153	118.3
HF Well Completions, Controlled	17,557 scf/HF completion[s]	1,319 HF oil well completions [t,2]	0.023	0.4

Table XX: Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3 Table A-127, Methodological Descriptions for Additional Source or Sink Categories[7]

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)[aa]	Calculated Potential (Mg)[bb]
Drilling, Well Completion, and Well Workover			
Gas Well Completions without Hydraulic Fracturing	767 completions/year[g]	707.23-854.65 scf/completion[b]	11.3

[7] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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Gas Well Workovers without Hydraulic Fracturing	8,933 workovers/year[a,2]	2,367.7-2,861.3 scf/workover[b]	445.8
Hydraulic Fracturing Completions and Workovers that vent*	1,791 completions and workovers/year[c]	36.82 MT/(completion or workover)[h]	65940.7
Flared Hydraulic Fracturing Completions and Workovers*	548 completions and workovers/year[c]	4.91 MT/(completion or workover)[h]	2690.6
Hydraulic Fracturing Completions and Workovers with RECs*	1043 completions and workovers/year[c]	3.24 MT/(completion or workover)[h]	3379.6
Hydraulic Fracturing Completions and Workovers with RECs that flare*	1979 completions and workovers/year[c]	4.88 MT/(completion or workover)[h]	9653.4
Well Drilling	18,837 wells[i,1]	2,505.9-2,965.0 scf/well[j]	971.6

Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[8]

2.2.2.1 Green completion equipment

Sources For Leaks		
Connectors	**Hammer Unions**	**Choke Manifold**
Separator	**Temporary Piping Connector**	**Pressure Regulation**
"Gas Buster" Tank		**Blow Down**

After a well completion or workover, the formation and well bore is cleaned of fracture fluid and debris. Conventionally, this debris and fluid is collected into open pits or tanks and the gas entrapped in the fluid and cuttings is vented or flared. Green completions are methods used to lower these methane losses during well completions and workovers. When using green completion equipment gas and hydrocarbon liquids are physically separated from other fluids and cuttings and captured.

Green completion equipment is generally comprised of a choke manifold, separator, temporary piping connections and other pressure regulating equipment. Such connections are made up using hammer unions, and are pressure tested for significant leakage (and other performance issues) prior to use. These connections are anticipated to leak to some degree and it is unclear if the emission factors utilized to estimate methane emissions for production are suitable for quantifying emissions from completions equipment. In addition, completion equipment can include a "gas buster" tank that allows the operator to blown down equipment if they experience

[8] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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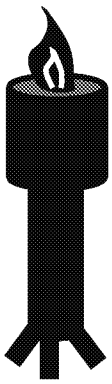
sand buildup or other operational issues. When equipment is blown down to the "gas buster" any natural gas entrained in the flowback fluid is released to the atmosphere

2.2.2.2 Flare

Sources For Leaks		
Malfunction	**Connectors**	**Pressure Gauges**



Flares are used to dispose of gas released during completion or production. Flares have an open flame, and generally equipped with a pilot flame fueled using LPG or an electronic ignitor. Flares come in a variety of heights and configurations, and can be used on high and low pressure gas streams. Depending on the waste stream being combusted, gas volume and velocity, and other constituents of the gas may have widely varying destruction efficiencies.

Flare emissions are typically a function of the destruction efficiency, so if a flare is 98% efficient, then 2% of the waste stream is released uncombusted. In addition, malfunctions of the pilot flame or electronic ignition system can result in uncontrolled emissions of gas to the atmosphere. In addition, flares utilized during completion operations can be mobile, and as such are connected to completion equipment using temporary piping. See "Green completions equipment", above) for a description of potential fugitive methane sources

2.2.2.3 Condensate and produced water tanks

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)[aa]	Calculated Potential (Mg)[bb]
Condensate Tank Vents			
Condensate Tanks without Control Devices	139 MMbbl/yr[k,1]	21.87-302.75 scf/bbl[l,]	253,092.6
Condensate Tanks with Control Devices*	139 MMbbl/yr[k,1]	4.37-60.55 scf/bbl[l]	50,618.5

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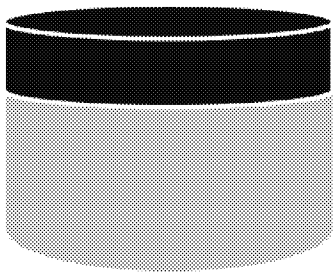
Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[9]

Sources For Leaks		
Flashing	**Working**	**Breathing**



Condensate and produced water tanks used in the oil and natural gas production sector are shop fabricated and transported to site for installation. Both the federal greenhouse gas reporting program and new source performance standards include methods for quantification of methane emissions from such tanks. Briefly, emissions result from three overall processes: flash, working, and breathing. Flash emissions are evolved when a pressurized fluid stream flows into an atmospheric tank. The resulting change in pressure releases gasses, including methane, previously held in solution. Working losses result from tank fluid level changes that push vapors trapped in the tank head space to escape to the atmosphere or to an emission collection system. Breathing losses occur as the ambient temperature changes and fluids in the tank expand, which can push vapors trapped in the tank head space to escape to the atmosphere or to an emission collection system.

2.2.3 Producing wells

[9] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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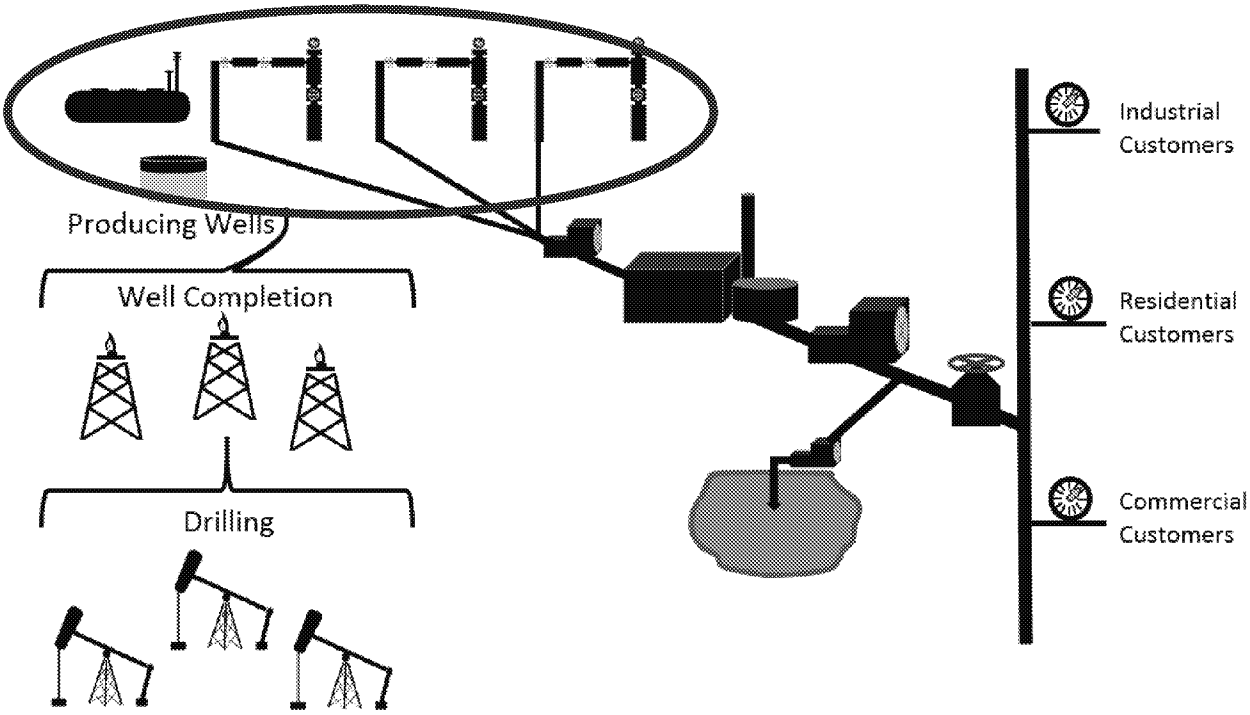

Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)			Field Production			Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Source (GHG Inventory)	Petroleum Systems (3-37)					
Stage (GHG Inventory)	Production Field Operations (Table A-127)				Crude Oil Transportation	Refining
Petroleum Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Crude Oil to Refineries	
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		

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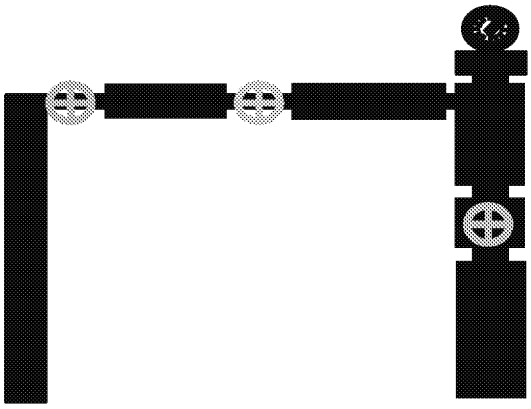
2.2.3.1 Oil Production Field Production



Of the four sectors of natural gas systems (production, processing, transmission/storage, and distribution), production accounted for 62 ± % of emissions in 2014 according to the EPA GHG Inventory.[1] A study by Allen et al.[2] found that 61% of production emissions were from pneumatic controllers and 30% was from equipment leaks. It should be noted that the EPA inventory considers gathering and boosting within the production sector whereas in this ITRC report, production is considered part of the transmission sector.

Production emissions are broken down as those from the following six activities: flowback, pumps, pneumatic controllers, equipment leaks, liquid unloading, and workovers. A discussion of the life cycle of production emissions including drilling, fracturing and well completion, and production will follow.

2.2.3.2 Natural Gas Production from Oil Wells

All production activities the general public sees begin with the drilling of the well to access an oil-producing geologic formation. Historically, oil well production was limited to vertical wells and initially to relatively shallow depth. Fracturing of productive strata has also been employed for many years. Recent technological advances first seen only on offshore drilling rigs, like directional drilling, have been adopted by onshore operators. That innovation, coupled with advanced well stimulation (or completion) techniques like hydraulic fracturing has enabled onshore oil producers (Exploration and Production or E&P companies) to access formations that were previously inaccessible, considered uneconomic using prior drilling technology, or both. These advancements in technology have resulted in a significant shift in the economy of the United States, moving in the course of a decade from a state of relative resource scarcity to becoming one of the largest producers of natural gas worldwide. This change presents both opportunities and challenges. One of these challenges is how best to cope with potential climate change while embracing this new energy economy. Emissions of methane from oil production contribute to this issue of climate change, and as a consequence have been the subject of regulation at the state and federal level.

The federal greenhouse gas (GHG) reporting program established in 40 Code of Federal Regulations Part 98, Subpart W is focused on capturing GHG emissions data (specifically including methane) from oil and natural gas production. It captures a number of known sources of direct and indirect methane emissions, which are listed in the subpart.

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2.2.3.3 Natural Gas Field Production

Table A-134, from the EPA Greenhouse Gas Inventory 2014, lists many emissions activities for gas and condensate production operations and for midstream operations.

In alignment with the EPA GHG Inventory, onshore production operations will include:

- Gas Wells
- Well Pad Equipment
- Drilling
- Well Completion and Well Workover
- Normal Operations
- Condensate Tank Vents
- Compressor Exhaust Vented
- Well Cleanups
- Blowdowns (except pipeline blowdowns which are part of midstream)
- Upsets
- Produced Water from CBM Wells

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)[aa]	Calculated Potential (Mg)[bb]
Natural Gas Production Stage			
Gas Wells			
Associated Gas Wells	503,873 wells[a,1,cc]	NA[dd]	0.0
Non-associated Gas Wells (less fractured wells)	205,363 wells[a,1]	7.43-42.49 scfd/well[b]	17,754.5
Gas Wells with Hydraulic Fracturing	250,777 wells[a,1]	7.59-42.49 scfd/well[b]	35,085.1
Well Pad Equipment			
Heaters	99,038 heaters[c,d,2]	14.87-67.29 scfd/heater[b]	23,953.4
Separators	306,377 separators[c,d,2]	0.94-142.27 scfd/separator[b]	118,591.2
Dehydrators	17,126 dehydrators[c,d,2]	23.18-106.25 scfd/dehydrator[b]	8,417.5
Meters/Piping	523,885 meters[c,d,2]	9.43-61.68 scfd/meter[b]	107,173.2
Compressors	48,518 compressors[c,d,2]	263.85-312.19 scfd/compressor[b]	96,170.6

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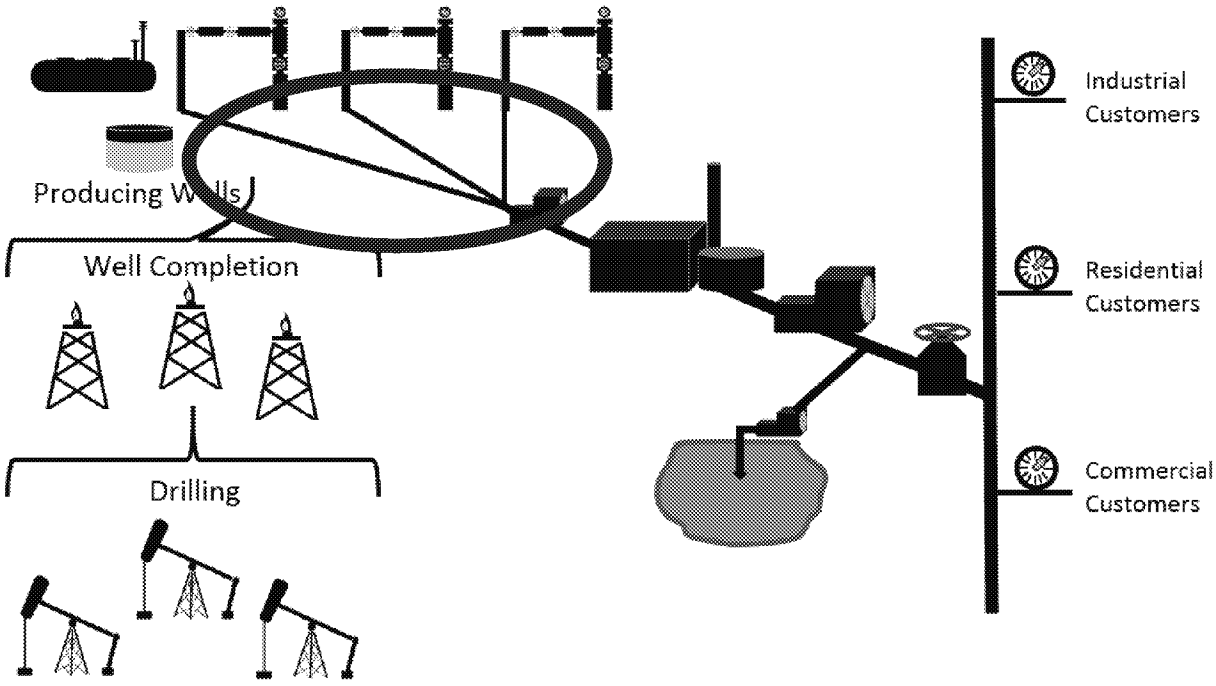
Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[10]

2.2.4 Gathering lines



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Midstream operations will include:

[10] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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- Gathering and Boosting Compressor Stations
- Pipeline Leaks
- Pipeline Blowdowns

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)[aa]	Calculated Potential (Mg)[bb]
Natural Gas Production Stage			
Gathering and Boosting			
Gathering and Boosting Stations*	4,999 stations[e,2]	53,066 scfd CH4/station[e]	1,864,870.3
Pipeline Leaks	431,051 miles[f,2]	52.38-61.97 scfd/mile[b]	169,701.4
Blowdowns			
Pipeline Blowdowns	431,051 miles (gathering),[b,2]	3,719-4,400 scfy/compressor[b]	3,713.8

Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[11]

Gathering pipelines transport natural gas from well pads to processing plants or transmission pipelines. The EPA U.S Greenhouse Gas Inventory estimates that there are approximately 420,000 miles of gathering pipelines in the country. Gathering lines are associated with small, aboveground auxiliary equipment such as pipeline interconnects and pigging stations. Gathering stations are larger associated facilities where gas is compressed and occasionally treated to remove liquids or acid gases. Gathering station emissions are well characterized, but very little data exist on emissions from gathering pipelines or small auxiliary equipment. There are two recent studies that have assessed emissions from gathering pipelines but have not been published yet. A study by the National Energy Technology Laboratory used a utility terrain vehicle equipped with a methane sensor to detect methane emissions along 138 miles of gathering pipeline right of way in Pennsylvania. Preliminary results indicate that only one leak was detected during the survey, a blowdown valve associated with aboveground equipment. As part of the Research Partnership to Secure Energy for America (RPSEA) Fayetteville Shale Campaign, 60 miles of gathering pipelines and 95 auxiliary equipment locations were screened with a vehicle-mounted leak detection system. Pipeline leaks were quantified with a flux chamber. Aboveground leaks were identified with OGI and then quantified with a high-flow

[11] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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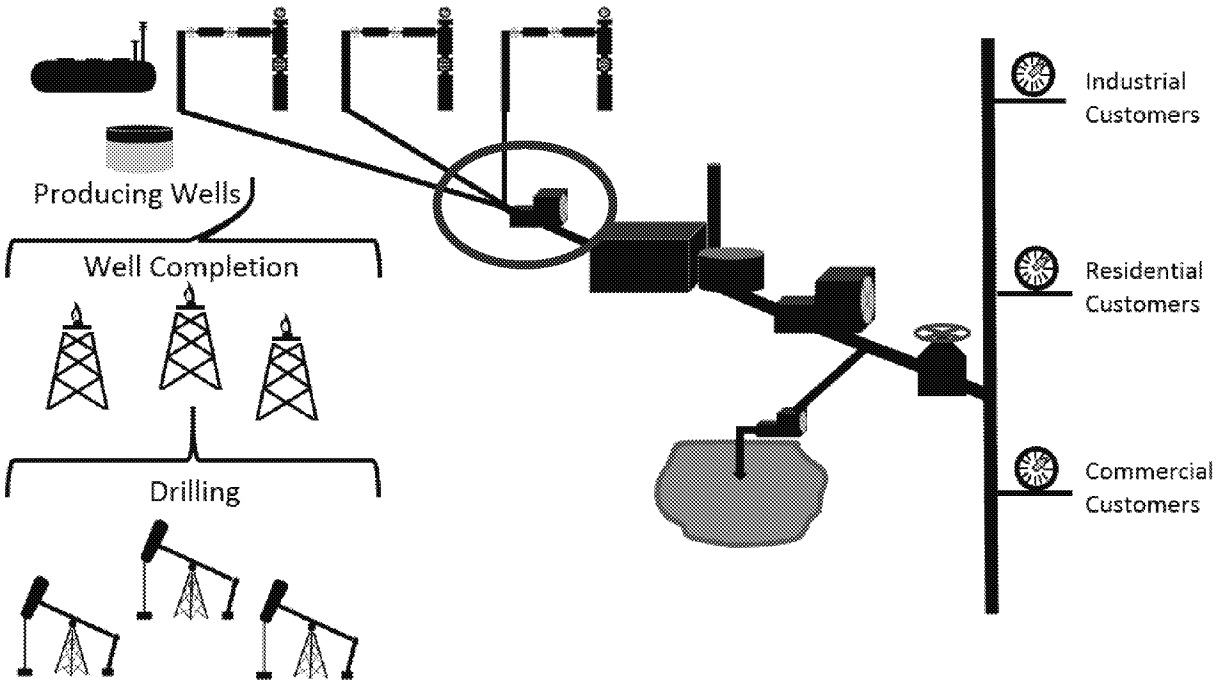
dilution sampler. For aboveground pigging stations, 75% of locations had detected emissions with an aggregate total of 0.7 kg/hr CH4. For aboveground block valves, 44-percent of sites had detected emissions with an aggregate total of 0.1 kg/hr CH4. For both pigging stations and block valves, the top 5-percent of locations accounted for 50-percent of total emissions. Only a single pipeline leak was detected, but its emissions rate of 4 kg/hr CH4 exceeded the total of all aboveground leaks. Although these initial studies suggest that gathering pipeline emissions are small, their very small coverage (<0.05%) of total pipeline miles and finding of highly skewed emission rates indicates that more work is needed to accurately assess emissions from this source.

http://www.rpsea.org/media/files/files/e86f7c1a/EVNT-PR-2016-SP_In-House_Air_Emission_Research_Projects_Quality_Impacts_Shale_Development-Mundia-Howe-05-26-16_OwGkPGu.pdf

http://www.rpsea.org/media/files/files/f74d3577/EVNT-PR-2016-SP_12122-95_Methane_Emissions_Reconciliation_Facility_Level-Zimmerle-05-26-16.pdf

2.2.5 Gathering and boosting compressors



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

2.2.5.1 Gathering and Boosting Stations

Activity	National Activity Data	National Emission Factor or Range of Regional Values (Potential)aa	Calculated Potential (Mg)bb
Gathering and Boosting			
Gathering and Boosting Stations*	4,999 stations[e,2]	53,066 scfd CH4/station[e]	1,864,870.3
Pipeline Leaks	431,051 miles[f,2]	52.38-61.97 scfd/mile[b]	169,701.4

Table XX: Fugitive methane emissions from natural gas production. Adapted from EPA ANNEX 3 Table A-134, Methodological Descriptions for Additional Source or Sink Categories[12]

Gathering stations are facilities that collect, compress, and sometimes treat natural gas from multiple wells and send the gas to processing plants or transmission pipelines.

Gathering lines are commonly smaller diameter pipelines (generally in the range of 6 to 20 inches) that move natural gas from the wellhead to a natural gas processing facility or an

[12] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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interconnection with a larger mainline transmission pipeline. "Gathering & boosting" compressor stations (SIC 1311) for gathering lines are often larger than transmission line compressor stations (SIC 4922) due to multiple pipelines coming into the station inlet, and in some cases, additional equipment needed to filter and remove liquids from the gas stream. Glycol dehydrators remove water, and Amine units remove CO_2 and H_2S, from the gas stream.

Midstream, gathering and boosting compressor stations receive gas from the surrounding gathering field. The gas can enter the facility at various pressures depending on the gas gathering pipeline(s) pressure(s). The gas is routed to separators (or slug catchers) to knockout heavier hydrocarbon liquids and water which are routed to either pressurized condensate stabilizers or to atmospheric storage tanks. Those liquids will ultimately be loaded onto trucks for transportation or piped offsite. The gas from the inlet separator is routed to compression.

Prior to 2016, EPA's estimate of gathering stations emissions was split into three categories (stations, small compressors, and large compressors). This was based on data from the 1990s EPA/ Gas Research Institute (GRI) study that included measurements from well pad compressors and gathering stations. Total emissions from these sources were estimated to be 226 [redacted] CH_4 in the EPA 2014 Greenhouse Gas Inventory (GHGI). The 2016 EPA GHGI replaced this estimate with a single value for gathering stations based on a study by Colorado State University (CSU) (Roscioli et al. 2016, Mitchell et al. 2016, Marchese et al. 2016). The study used the dual gas downwind tracer technique to quantify site-level methane emissions at 114 gathering stations operated by five companies in ten basins. Emission rates ranged from 0.7 to 700 kg/hr CH_4 with an average of 55 kg/hr. As a percentage of gas throughput, loss rates ranged from 0 to 70% with a weighted average of 0.2%. Emissions were highly skewed with 30% of facilities responsible for 80% of emissions. Onsite surveys with infrared camera revealed that 20% of facilities had substantial tank venting and these sites had on average four times higher emission rates than sites without substantial venting. Mitchell et al. (2016) used a Monte Carlo simulation to estimate national emissions from the Mitchell et al. (2016) data. They estimate that in 2012 there were 4,549 gathering facilities in the U.S. with total emissions of 1,697 Gg CH_4, or 0.40% of gas throughput. In the 2016 GHGI, EPA used this data to estimate gathering station emissions of 1,865 Gg CH_4, which makes gathering stations the largest single source in Petroleum and Natural Gas Systems.

Although the CSU study did not quantify component-level emissions, gathering stations likely have a similar profile as transmission compressor stations with the largest sources including compressor venting, compressor exhaust, and equipment leaks. Other sources such as storage tanks, pneumatic controllers, and blowdowns may also contribute to substantial emissions at some facilities. Ongoing research at compressor stations may provide data on component-level emissions at gathering facilities. Additionally, the EPA GHG Reporting Program (GHGRP) has been revised to require reporting of emissions and activity data by gathering and boosting facilities, which are defined at the basin-level by the rule, starting in the 2016 reporting year.

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2.2.5.2 Midstream – Gathering and Boosting Compressor Stations

Compressor stations are an integral part of the natural gas pipeline network that moves natural gas from individual producing well sites to end users. As natural gas moves through a pipeline, distance, friction, and elevation differences slow the movement of the gas, and reduce pressure. Compressor stations are placed strategically within the gathering and transportation pipeline network to help maintain the pressure and flow of gas to market.[13] A simplified facility process flow diagram of an example compressor station is shown in Figure XX. Photos in Figures XX and XX indicate typical compressor station equipment.

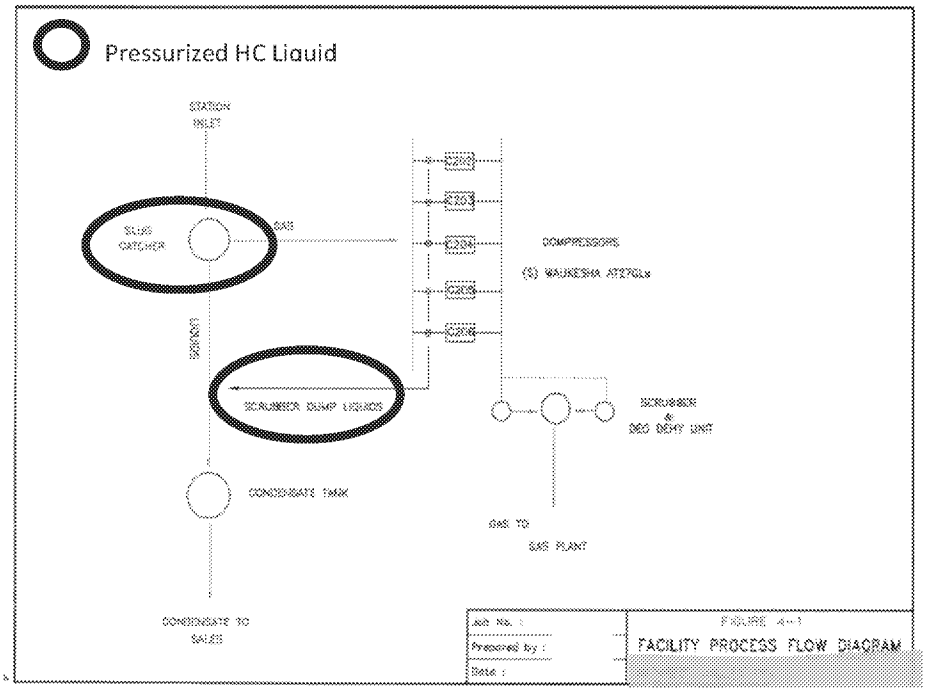

Figure XX - Compressor Station - Simplified Process Flow Diagram

Gathering lines are commonly smaller diameter pipelines (generally in the range of 6 to 20 inches) that move natural gas from the wellhead to a natural gas processing facility or an interconnection with a larger mainline transmission pipeline. "Gathering & boosting" compressor stations (SIC 1311) for gathering lines are often larger than transmission line compressor stations (SIC 4922) due to multiple pipelines coming into the station inlet, and in some cases, additional equipment needed to filter and remove liquids from the gas stream. Glycol dehydrators remove water, and Amine units remove CO_2 and H_2S, from the gas stream.

[13] Marcellus Education Fact Sheet, Penn State Extension Natural Gas Website: http://extension.psu.edu/publications/ee0154

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Midstream, gathering and boosting compressor stations receive gas from the surrounding gathering field. The gas can enter the facility at various pressures depending on the gas gathering pipeline(s) pressure(s). The gas is routed to separators (or slug catchers) to knockout heavier hydrocarbon liquids and water which are routed to either pressurized condensate stabilizers or to atmospheric storage tanks. Those liquids will ultimately be loaded onto trucks for transportation or piped offsite. The gas from the inlet separator is routed to compression.

Compressors can use gas or electric engines (or gas turbines – seen more often in transmission pipeline compressor stations with more steady loads) to drive the compressors that increase the gas pressure for subsequent treatment. Or, if the gas quality is adequate, direct tie-in to transmission pipelines for sales to market. Since compression raises the gas temperature, the compressed gas is cooled between stages (the larger the difference between inlet pressure and outlet pressure of the facility, the more stages of compression are needed). The inter-stage coolers typically result in some partial condensation that is removed in inter-stage scrubbers. These condensed hydrocarbon liquids, which can be at increasingly higher pressures for each stage, are routed to condensate stabilizers or atmospheric storage tanks where flash, working/standing/breathing emissions occur. Compression also includes associated equipment such as air cooler/heat exchangers (to cool the gas stream between each stage of compression), inter-stage scrubbers (to remove hydrocarbon liquids from the cooled gas stream between each stage of compression), lube oil systems, filters, coalescers, etc. Malfunctioning valves on the interstage scrubbers can allow for continuous gas seepage, or unintentional gas carrythrough which would be evident from the destination of those liquids, e.g. the storage tanks.

If water is present after compression it is removed from the gas by glycol dehydrators which can have two potential vented emissions:

- from a flash tank if present (and not routed to fuel the reboiler) and
- from the regenerator/still vent/reboiler stream

If permit or regulation requires the reduction of emissions from tanks and glycol dehydrators, then those emissions will be routed through a closed vent system to either a Vapor Recovery Unit (VRU) to be recompressed and routed to the facility inlet, or to a combustor or flare control device. The dry, compressed gas leaves the compressor station at a high enough pressure for further gas processing at a gas plant or, if the quality of the gas can meet pipeline specs, can tie directly into a transmission, mainline pipeline for sales to market. To meet transmission pipeline specs, the high pressure gas may need to be routed through a JT (Joule-Thompson) skid or dewpoint control skid where further hydrocarbon liquid dropout can occur. These high-pressure

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liquids can be routed to a condensate stabilizer or the atmospheric storage tanks. The higher the pressure differential, the more flash emissions will occur.

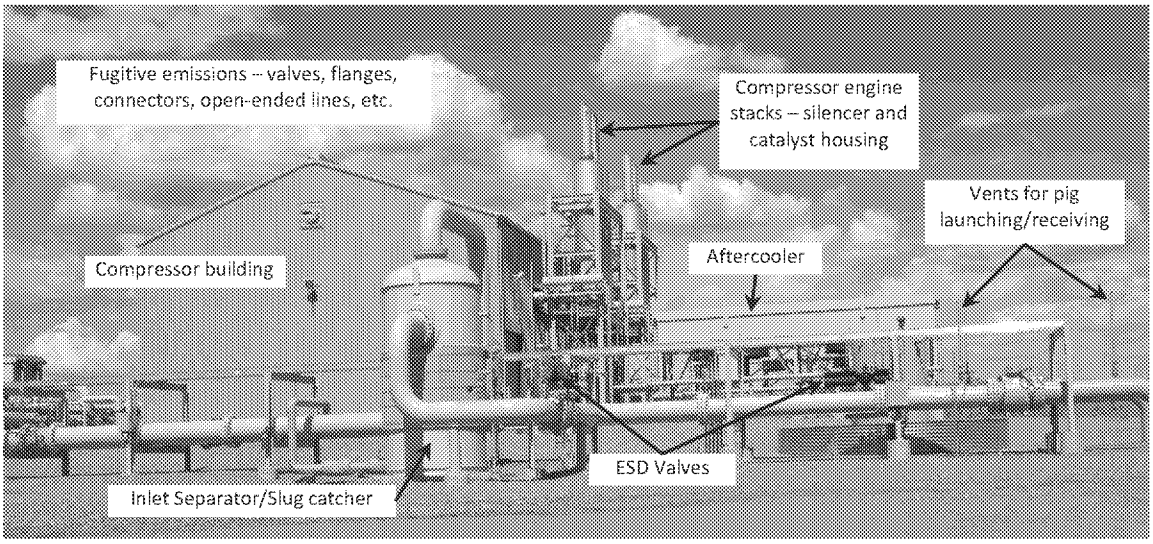

Figure 1.5 - Compressor Station - Inlet and compressor building

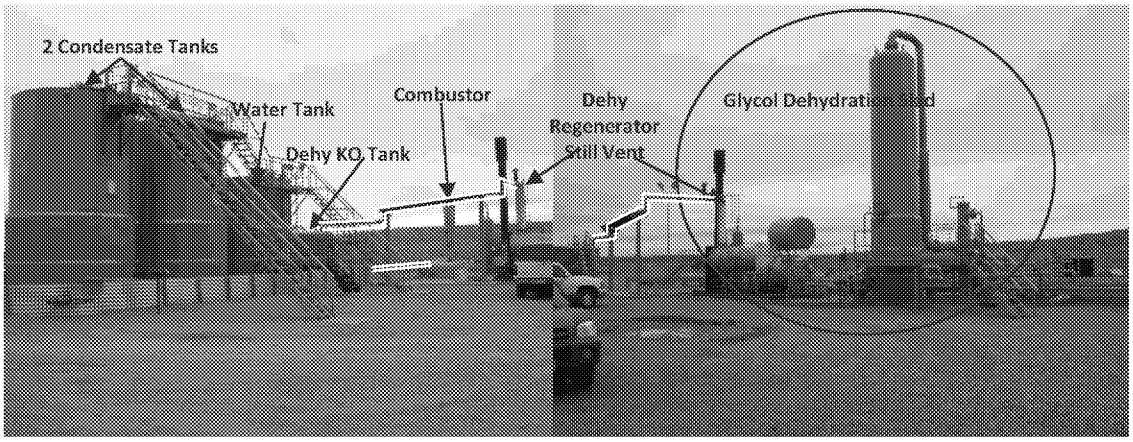

Figure 2.6 - Compressor Station - Glycol Dehydrator skid, storage tanks. Emissions from dehydrator and tanks are routed through a closed vent system (outlined in yellow) to a combustor control device

Currently in the US EPA GHG Inventory, methane emissions at Gathering & Boosting compressor stations, between the production wells and the gas processing plant, are captured in a single line item (Table A-134). Methane emission sources that could be detected include:

Intentional venting:

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- Hydrocarbon liquid storage tanks, glycol dehydrator regenerators/reboilers & flash tanks, and amine units that are not required to control their emissions
- Compressor distance piece vent/drain (Figure 9)
- Compressor crankcase vent
- Compressor rod packing vent/drain
- Gas-powered pneumatic devices – controllers, chemical pumps
- Blowdown emissions to remove gas from equipment for maintenance (Figures 4 and 5)
- Emergency Shutdown (ESD) events

Unintentional:

- Fugitive emissions from valves, flanges, connectors, open-ended lines
- Hydrocarbon liquid storage tanks, glycol dehydrator regenerators/reboilers & flash tanks, and amine units that are required to control their emissions – through pressure relief devices like thief hatches, pressure relief valves (figures 6 and 7)
- Excessive distance piece venting from unintentional gas carry through
- Malfunctioning pneumatic devices
- Blowdown emissions due to improperly seated valves in blowdown piping (see Figures 4 and 5)
- ESD vent emissions due to improperly seated valves
- Unburned hydrocarbons, methane slip from any equipment that burns "waste gas" or fuel gas streams; e.g. combustors, flares, engines, turbines, reboilers, heaters, etc. (Figures 8, 10 and 11)

Every station has an emergency shutdown system (ESD) connected to a control system that can detect abnormal conditions such as an unanticipated pressure drop or natural gas leakage. These emergency systems will automatically stop the compressor units and isolate and vent compressor station gas piping (sometimes referred to as a blow down). There can be individual blowdown stacks per compressor unit or a single, central blowdown stack for the entire compressor station. Valves within the piping system linked to a blowdown stack can sometimes not close completely and so gas can seep out of blowdown stacks (see Figure 4 and 5).

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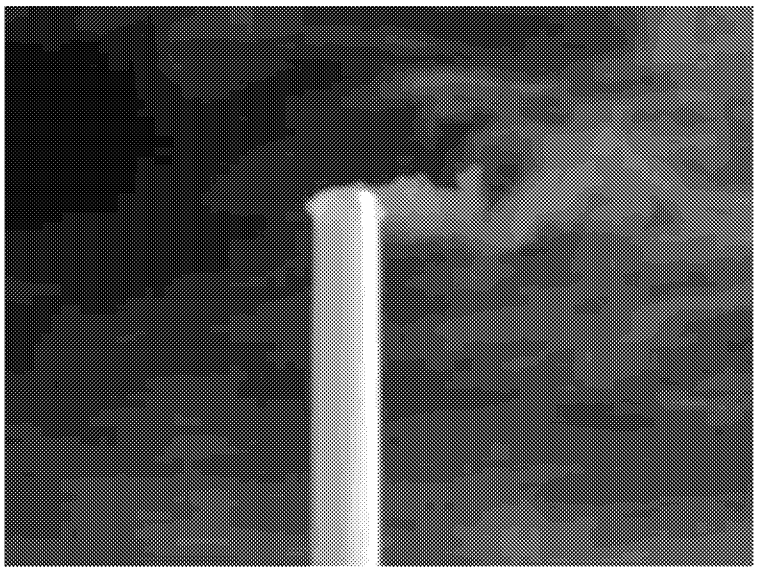

Figure 2.7- Centralized blowdown stack in a compressor station where several pieces of equipment are piped to.

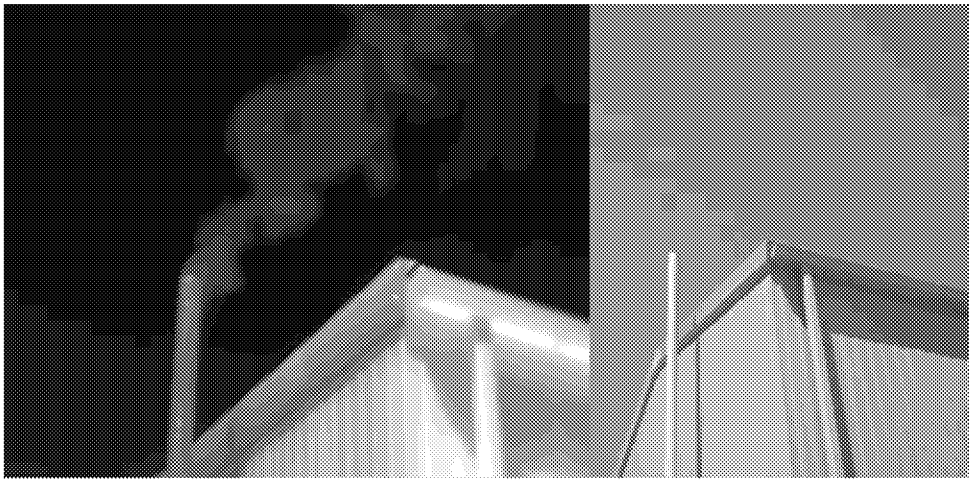

Figure 2.8 - Blowdown stack by individual compressor unit (inside building).

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Figure 2.9- Emissions from closed vent systems used to route emissions to a control device. Top left and clockwise: thief hatch relieving pressure; spark arrestor on dehydrator knockout tank relieving pressure; pressure relief valve opened on glycol dehydrator regenerator stream; pressure relief valve venting on top of condensate storage tank.

Figure 2.10 - From visual observations, examples of "burped up" oil under and around pressure relief devices (thief hatches or valves) of controlled tanks at compressor stations, indicative of over-pressure events where gas emissions would also be present.

Figure 2.11 - Distance piece drain vent from single compressor. Note sprayed and pooled oil underneath vent.

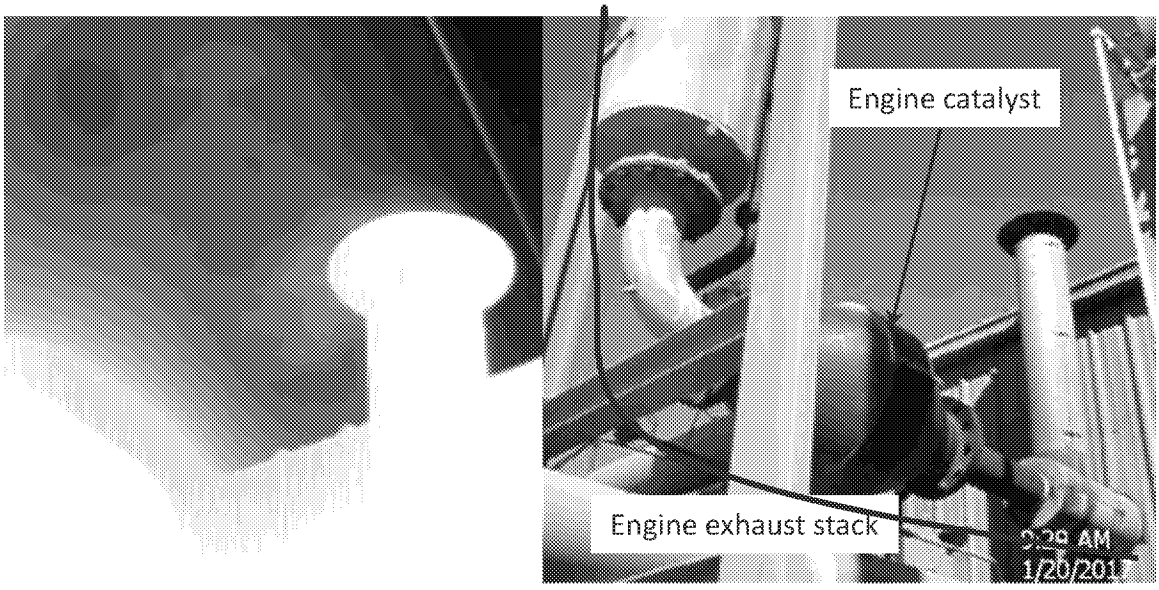

Figure 2.12 - Engine emissions escaping before the emission control catalyst.

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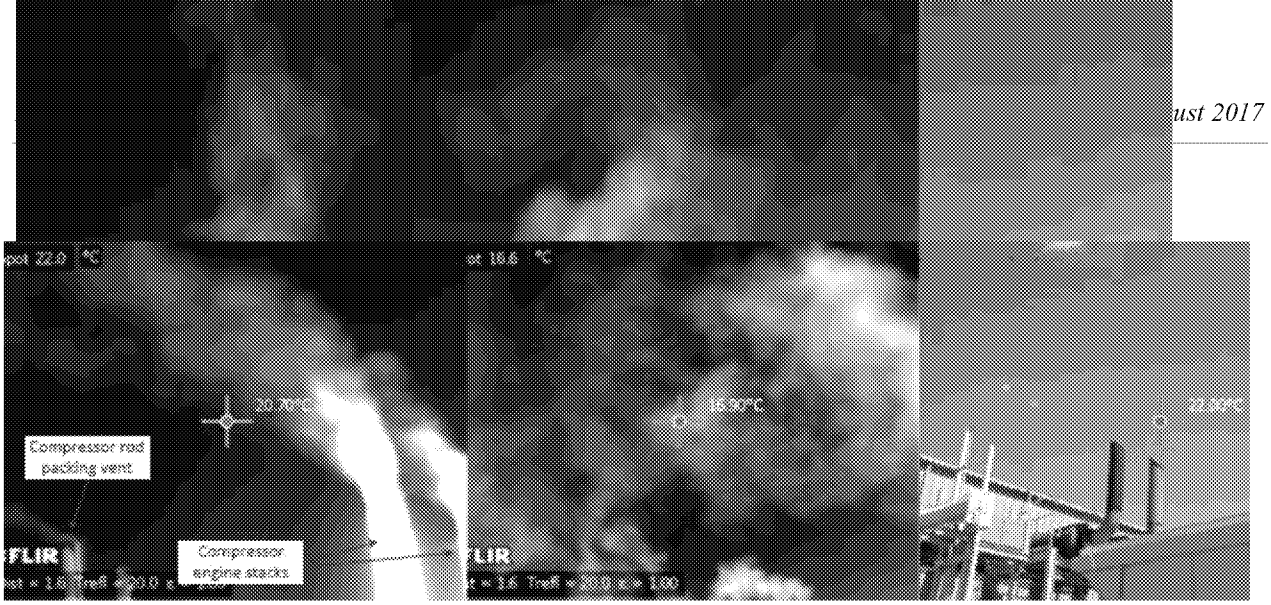
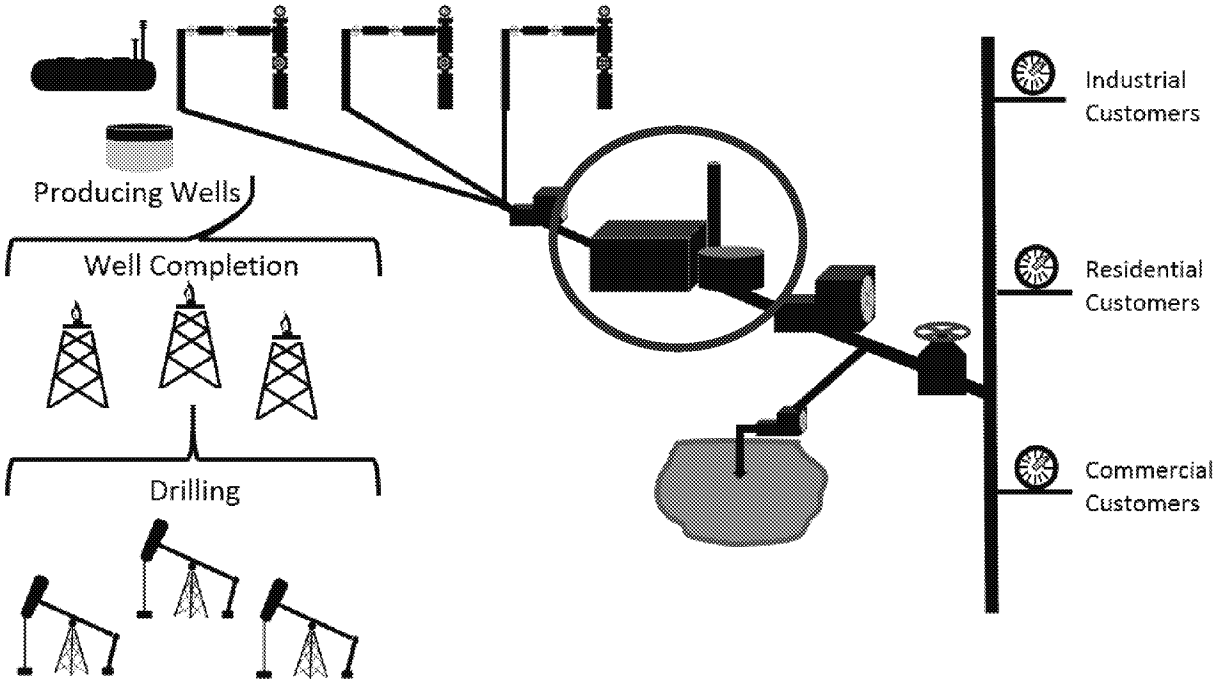


Figure XX - Unburned hydrocarbons observed from compressor engine stacks. Pan IR camera to move white hot stacks out of viewfinder to check if plume hanging together.

2.3 Processing - Gas Processing Plants



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressor	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Activity	Activity Data		Emission Factor (Potential)[aa]		Calculated Potential Emissions (Mg)
Normal Fugitives					
Plants	668	plants[a,1]	7,906	scfd/plant[b]	37,126.4
Reciprocating Compressors	6,020	compressors[c,2]	11,196	scfd/compressor[b]	473,828.9
Centrifugal Compressors (wet seals)	665	compressors[d,2]	51,370	scfd/compressor[d]	240,031.0
Centrifugal Compressors (dry seals)	306	compressors[d,2]	25,189	scfd/compressor[d]	54,117.2
Vented and Combusted					
Gas Engines	43,251	MMHPhr[c,2]	0.24	scf/HPhr[b]	199,922.8
Gas Turbines	51,283	MMHPhr[c,2]	0.01	scf/HPhr[b]	5,630.0
AGR Vents	339	AGRunits[b,2]	6,083	scfd/AGR[b]	14,477.9
Kimray Pumps	1,566,830	MMscf/yr[c,2]	177.75	scf/MMscf[b]	5,364.0
Dehydrator Vents	14,115,586	MMscf/yr[c,2]	121.55	scf/MMscf[b]	33,045.3
Pneumatic Controllers	668	gasplants[a,1]	164,721	scfy/plant[b]	2,119.2
Routine Maintenance					
Blowdowns/Venting	668	gasplants[a,1]	4,060	Mscfy/plant[b]	52,234.7

Table XX: Fugitive methane emissions from natural gas processing. Adapted from EPA ANNEX 3 Table A-136, Methodological Descriptions for Additional Source or Sink Categories[14]

2.3.1 Cryogenic fractionation process

Field natural gas entering from well pads or gathering stations first enters separators (or slug catchers) to knockout heavier hydrocarbon liquids and water. By removing excess field water the separator provides operating flexibility in the case of wells sending a large volume of fluids to the facility in a relatively brief amount of time (a "slug"). This fluid, composed primarily of entrained or residual produced water and natural gas liquids (NGL), may be further separated and sent to storage in atmospheric tanks.

The incoming gas stream is further dehydrated using a dessicant system (which can be regenerated on site). Low (less than 10 ppm) moisture levels are required to avoid condensation issues in the cryogenic process. The dehydrated gas is then sent to a turboexpander (also referred to as an expander-compressor) where the gas is compressed and then allowed to depressurize inside a temperature-controlled cryogenic tower. The depressurization of the dehydrated gas under controlled conditions results in the separation of methane (which remains gaseous at the temperature and pressure of the tower) from the remaining NGL species (ethane, propane, butane, and hydrocarbons containing five or more carbon atoms). The methane comes off the top of the tower and is sent to resid compressors (residual gas). Depending on the

[14] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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availability of takeaway capacity or market, some cryo plants operate in an "ethane rejection" mode, where the ethane is sent to resid compression along with methane for compression and shipment to transmission. Where available, ethane can be separated and sold as a commodity. The remaining NGL (propane, butane, and C5+) are then stored in pressurized bullet tanks as a mixed intermediate product, commonly referred to as "Y-grade". This Y-grade is the feedstock for the next processing step, fractionation. Some sites perform this processing as an integrated facility, in other cases the Y-grade is transported to the fractionation plant by truck or pipeline.

2.3.2 NGL fractionation

NGL fractionation is at base a distillation under temperature-controlled conditions. The mixed feedstock is processed through distillation towers of varying temperatures and refluxed to ensure efficient product recoveries. There are generally three commodity products produced in this operation: propane, butane, and "natural gasoline" – a mixture of C5+ hydrocarbons. Natural gasoline is typically stored in a floating-roof tank, whereas propane and butane are stored in pressurized bullet tanks. Natural gasoline can be utilized by refineries as a process material or additive, and also by the fuel ethanol industry as a denaturant. The separated products are generally shipped off-site via pipeline or rail car.

Cryogenic processing and fractionation of NGL both require very precise pressure and temperature control. Cryogenic plants have potential methane emissions from the raw gas and separated methane streams. In contrast, methane emissions from fractionation plants of any significance are unlikely. Sources of emissions are described below, and in some cases reference earlier sections of this Chapter due to similarity of operations.

2.3.3 Flares

Both cryogenic and fractionation processes are equipped with one or multiple flares to handle essentially two conditions – routine operations where relatively small volumes of gas are required to be controlled for operational or safety reasons and emergency flares, which are typically an order of magnitude larger and designed to handle a large volume of gaseous hydrocarbons in the case of a catastrophic incident. These flares are equipped with flame sensors, continuous pilot flames (and in some cases a redundant backup), and flow measuring equipment. As a result, they are less likely to operate without the presence of a pilot flame. In most respects, the general operation and control efficiency of a flare is the same as described earlier.

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2.3.4 Facility blowdown

Both cryogenic and fractionation plants regularly blow down a portion of the plant for routine maintenance. Plants will also blow down to address non-routine maintenance or other operational issues. Specific to the cryogenic plant, such blowdowns have the potential to emit controlled or uncontrolled methane to the atmosphere depending on the design of the plant (whether the portion of the facility to be blown down is piped to a control device) and the volume and composition of the gas being evacuated.

2.3.5 Natural gas-fired heaters

Natural gas-fired heaters located at the facility would potentially be a source of leakage. Both cryogenic plants and fractionation plants employ thermal fluid heating systems, which require a process heater to heat that fluid. These process heaters (hot oil heaters or HOH) are typically fueled using natural gas, and as a result the piping components are subject to potential methane leakage.

2.3.6 Compressors

Compressors at these processing plants can be natural gas-driven or electrically driven when power is available and reliable. Employing electric drivers for such units eliminates potential emissions of methane from the fuel system, but emissions from scrubber bottles, intercoolers, and other functional components may still occur. Methane emissions from compressor operations were discussed earlier in this Chapter. Loading operations for Y-grade in cases where a compressor is employed in vapor recovery service (like truck loading of Y-grade), the pressurized portion of the collection system is subject to potential leakage. Leaking connections in the vacuum portion of the system would result in a loss of capture efficiency and increase in emissions of other hydrocarbon vapors. Methane would not be a component of the liquid being loaded and as a result emissions are not anticipated from this operation.

2.3.7 Tanks and vessels

Similar to discussions in prior sections of this Chapter, atmospheric tank emissions are a function of the pressure and composition of the incoming fluid stream. Atmospheric storage tanks at gas processing facilities may contain produced water or condensate. They may also be used as “slop tanks” where there is a mixture of different fluids in a single tank. Pressurized storage tanks (bullet tanks) are used to store propane and butane following fractionation. These hydrocarbons are gaseous at atmospheric pressure, and leaks from pressure vessels (like from an emergency relief valve) would not result in methane emissions.

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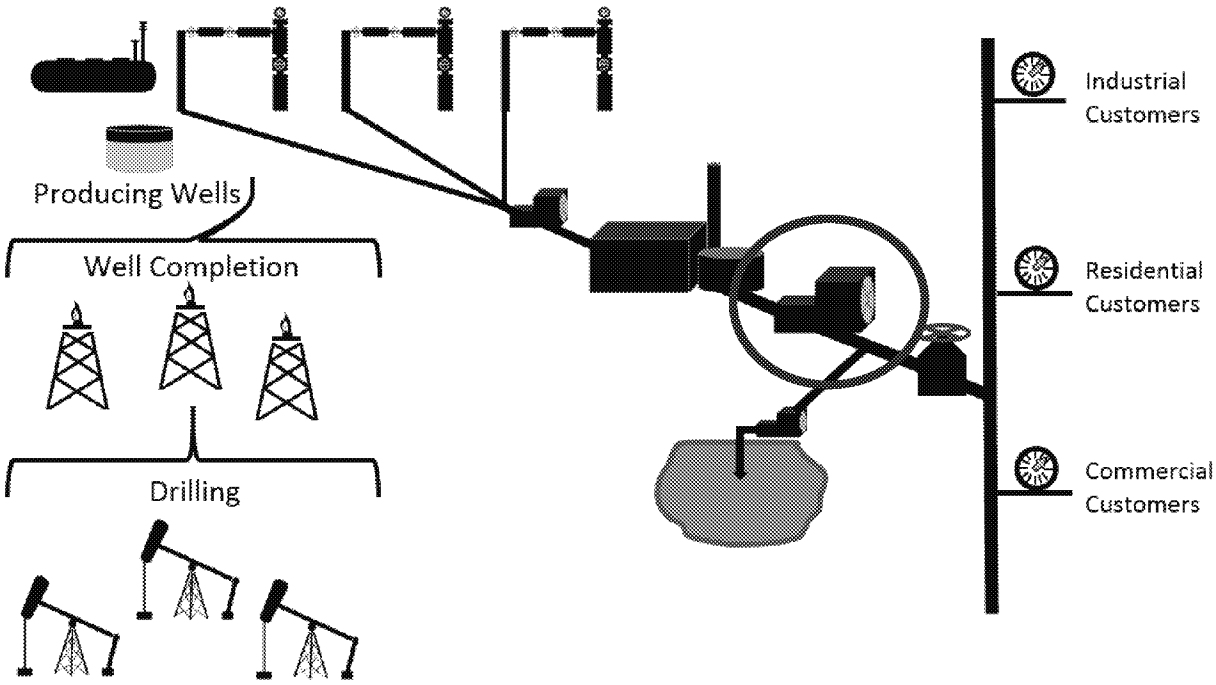
2.4 Transmission and Storage

2.4.1 Transmission compressors



Source (GHG Inventory)	Natural Gas Systems (2-17)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Activity	Activity Data	Emission Factor (Potential)[aa]	Calculated Potential Emissions (Mg)
Fugitives			
*Compressor Stations (Transmission)**			
Station Total Emissions	1,834 stations[c,d,2]	44,459 scfd/station[c,d,bb]	573,179.2

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Station + Compressor Fugitive Emissions	5,221 compressors[c,d,2]	9,104 scfd/station[c,d,bb]	117,370.9
Reciprocating Compressor	2,173 compressors[c,d,2]	9,246 scfd/compressor[c,d,bb]	339,361.9
Centrifugal Compressor (wet seals)	869 compressors[c,d,2]	9,673 scfd/compressor[c,d,bb]	59,092.2
Centrifugal Compressor (dry seals)	1,304 compressors[c,d,2]	6,259 scfd/compressor[c,d,bb]	57,354.2
M&R (Trans. Co. Interconnect)	2,686 stations[e,2]	3,984 scfd/station[b]	75,230.0
M&R (Farm Taps + Direct Sales)	79,646 stations[e,2]	31.20 scfd/station[b]	17,468.9
Normal Operation			
Dehydrator vents (Transmission)	1,169,007 MMscf/yr[b,2]	93.72 scf/MMscf[b]	2,110.1
Dehydrator vents (Storage)	2,169,267 MMscf/yr[b,2]	117.18 scf/MMscf[b]	4,895.8
Compressor Exhaust			
Engines (Transmission)	53,295 MMHPhr[b,2]	0.24 scf/HPhr[b]	246,351.2
Turbines (Transmission)	12,717 MMHPhr[b,2]	0.01 scf/HPhr[b]	1,396.1
Engines (Storage)	5,339 MMHPhr[b,2]	0.24 scf/HPhr[b]	24,677.0
Turbines (Storage)	1,875 MMHPhr[b,2]	0.01 scf/HPhr[b]	205.9
Generators (Engines)	2,608 MMHPhr[b,2]	0.24 scf/HPhr[b]	12,055.2
Generators (Turbines)	31 MMHPhr[b,2]	0.01 scf/HPhr[b]	3.4
*Pneumatic Devices Trans + Stor**			
Pneumatic Devices Transmission	47,140 devices[c,d,2]	30,611 scfy/device[c,d,bb]	27,792.1
(High Bleed)	4,129 devices[c,d,2]	151,969 scfy/device[c,d,bb]	12,085.2
(Intermittent Bleed)	39,216 devices[c,d,2]	19,712 scfy/device[c,d,bb]	14,888.7
(Low Bleed)	3,795 devices[c,d,2]	11,196 scfy/device[c,d,bb]	818.2
Pneumatic Devices Storage	23,964 devices[c,d,2]	63,622 scfy/device[c,d,bb]	29,364.5
(High Bleed)	8,379 devices[c,d,2]	147,983 scfy/device[c,d,bb]	23,882.0
(Intermittent Bleed)	13,482 devices[c,d,2]	19,333 scfy/device[c,d,bb]	5,020.1
(Low Bleed)	2,103 devices[c,d,2]	11,414 scfy/device[c,d,bb]	462.3
Activity	Activity Data	Emission Factor (Potential)[aa]	Calculated Potential Emissions (Mg)
Routine Maintenance/ Upsets			
Station venting Trans + Storage			
Station Venting Transmission	1,834 compressor stations c,d,2	4,359 Mscfy/station[b]	153,965.5
Station Venting Storage	356 compressor stations c,d,2	4,359 Mscfy/station[b]	29,887.7

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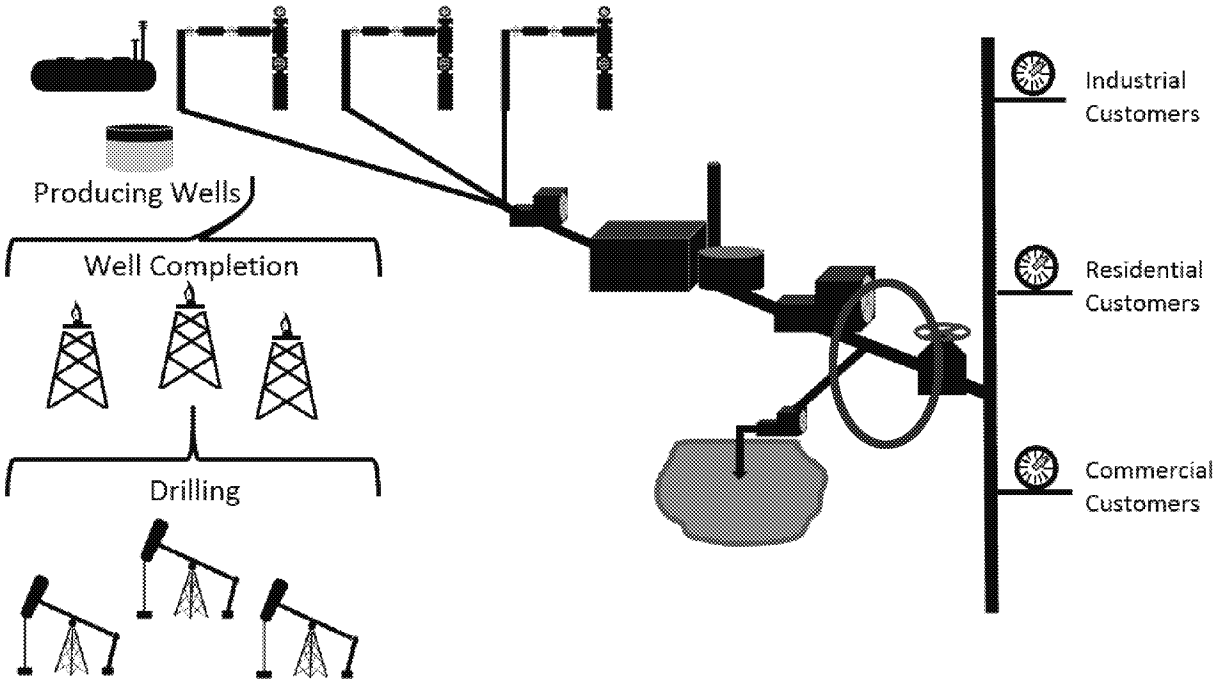
Table XX: Fugitive methane emissions from natural gas transmission. Adapted from EPA ANNEX 3 Table A-137, Methodological Descriptions for Additional Source or Sink Categories[15]

2.4.2 Transmission pipelines



[15] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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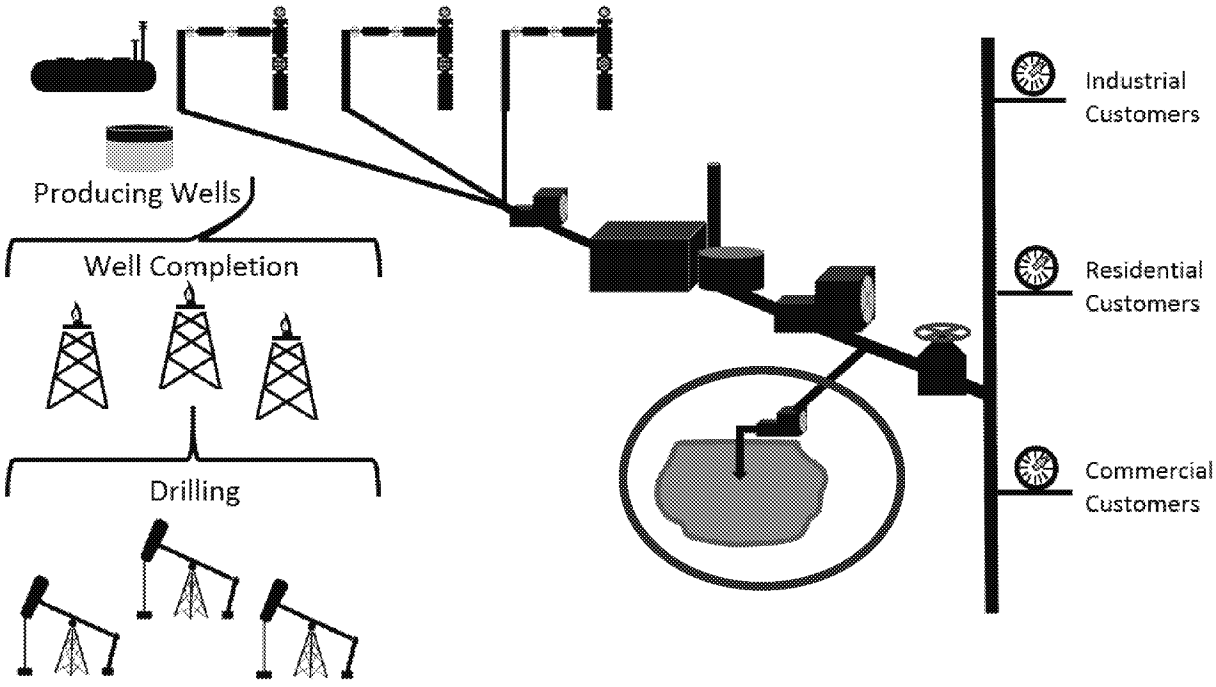
Source (GHG Inventory)	Natural Gas Systems (3-4)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Activity	Activity Data	Emission Factor (Potential)[aa]	Calculated Potential Emissions (Mg)
Fugitives			
Pipeline Leaks	301,748 miles[a]	1.55 scfd/mile[b]	3,296.3
Routine Maintenance/ Upsets			
Pipeline venting	301,748 miles[a,1]	31.65 Mscfy/mile[b]	183,939.2

Table XX: Fugitive methane emissions from natural gas transmission. Adapted from EPA Additional Source or Sink Categories[16]

2.4.3 Underground storage



[16] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Activity	Activity Data	Emission Factor (Potential)[aa]	Calculated Potential Emissions (Mg)
Fugitives			
Pipeline Leaks	301,748 miles[a]	1.55 scfd/mile[b]	3,296.3
Wells (Storage)	19,522 wells[b,2]	114.50 scfd/well[b]	15,714.0
Routine Maintenance/ Upsets			
Pipeline venting	301,748 miles[a,1]	31.65 Mscfy/mile[b]	183,939.2
Station venting Trans + Storage			
Station Venting Storage	356 compressor stations c,d,2	4,359 Mscfy/station[b]	29,887.7

Table XX: Fugitive methane emissions from natural gas transmission. Adapted from EPA ANNEX 3 Table A-137, Methodological Descriptions for Additional Source or Sink Categories[17]

Storage of natural gas may use underground formations such as salt caverns, mines, aquifers, depleted reservoirs and hard-rock caverns[18]. These formations may extend a few hundred to several thousand feet below the surface. Wells connect the storage reservoir to the surface wellhead assembly through a system of valves and pipes.

The wells are constructed with a larger diameter casing around a smaller diameter pipe. The casing sections, also known as joints, are 30-40 feet long and typically screw together with engineered connection collars. The collars include thread compound to assist in sealing each

[17] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

[18] EIA, 2015. The Basics of Underground Storage. <https://www.eia.gov/naturalgas/storage/basics/>

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joint. New storage wells contain a minimum of two casings, a surface casing and a production casing[19]. Often, owners will also cement between the two casings.

There are many components which go into underground storage which may contribute to leaking including:

- Conductor casing
- Surface casing
- Intermediate casing
- Production casing
- Production tubing

The mechanism for leaks are breaches in the seals of one of the above components. API found that the three primary leak mechanisms are[20]:

1) wellhead component or seal failure;

2) production casing leak; or

3) a downhole annular barrier breach (i.e. cement sheath)

These primary leak paths are depicted in Figure xx (NEED PERMISSIONS) and described more fully below:

BELOW IS VERBATIM FROM THE API REPORT – NEED TO SUMMARIZE[21]

1) Wellhead component or seal failure

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[19] API 1171
[20] API, June 2016. "Underground Natural Gas Storage: Integrity & Safe Operations."
< http://www.energyinfrastructure.org/energy-101/natural-gas-storage>
[21] API, June 2016. "Underground Natural Gas Storage: Integrity & Safe Operations."
< http://www.energyinfrastructure.org/energy-101/natural-gas-storage>

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This leak path occurs when the primary and secondary seals in the wellhead fail, allowing gas in the production casing to migrate past the seals into the production casing annulus. Leaks can also occur as a result of mechanical failure of other wellhead components such as casing slips, which can allow the production casing to drop free of the wellhead seal assembly. Observations that indicate a potential leak may exist include an increase in annular pressure or flow, dependent on the annular valve position during normal well operation mode.

For a release to occur, an initial failure takes place allowing pressurized storage gas to leave the production casing. Gas then either exits through an open annular valve or pressures up the annulus, if closed. To eliminate this type of release to the atmosphere, some operators close the annular valve while the well is in operational mode. However, if pressurized gas is trapped in the annulus and not allowed to dissipate, there is a possibility of additional secondary failures that will lead to more complex, and difficult to control, release paths, hence other operators leave the annular valves open in normal operational mode.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations; test wellhead seals, observe wellhead components for indications of leakage (noise and/or hydrate deposition), and/or perform interference testing between the production casing and production casing annulus to determine if the leak is at the surface or downhole. Leak resolution may include replacing the wellhead assembly or wellhead seals and/or repair or partial replacement of the production casing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

2) Production casing leak

This leak path occurs when the production casing wall is breached. Causes include but are not limited to production casing failure due to reduced casing wall thickness from corrosion and/or the introduction of higher pressures than containable for stimulation treatments, or production casing wall collapse from outside forces such as earth movement or foreign production operations.

Observations that indicate a potential leak may exist are lower than expected shut-in pressures or gas exiting somewhere outside of the structure of the wellbore.

The stored gas can escape outside the structure of the storage wellbore from deep underground and migrate through a path of least resistance upward until it reaches an alternative escape path. The escape path could be through an oil and gas, water, or abandoned well completed in a

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shallower permeable formation or the path could be all the way to an escape at the surface. Operators must understand subsurface geologic conditions to assess the risk of geologic migration.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations: obtain electric logs (pipe inspection, caliper, gamma ray-neutron, differential temperature, noise, spinner flow survey, etc.); install a bridge plug and pressure test the casing.

Options for the operator to resolve the breach may include partially replacing the production casing, installing a casing internal patch, cladding, or liner, and/or remedial cementing.

Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

3) Downhole annular barrier breach

This leak path occurs when gas and/or hydrostatic pressure in the annulus exceeds the strength of the rock below the intermediate or surface casing shoe, resulting in establishment of an escape path outside the wellbore. Observations that a potential leak may exist are gas exiting somewhere beyond the structure of the wellbore.

In this case storage gas finds a path of least resistance around the intermediate casing shoe and then into the subsurface lithology where it could enter an oil and gas, water, or abandoned well completed in a shallower permeable formation, or migrate all the way to an escape at the surface.

Diagnosing the failure mechanism requires the operator to obtain electric logs (gamma ray-neutron, differential temperature, ultrasonic/noise, etc.) as needed to determine the direct cause. In order to resolve this breach, the operators will usually require remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

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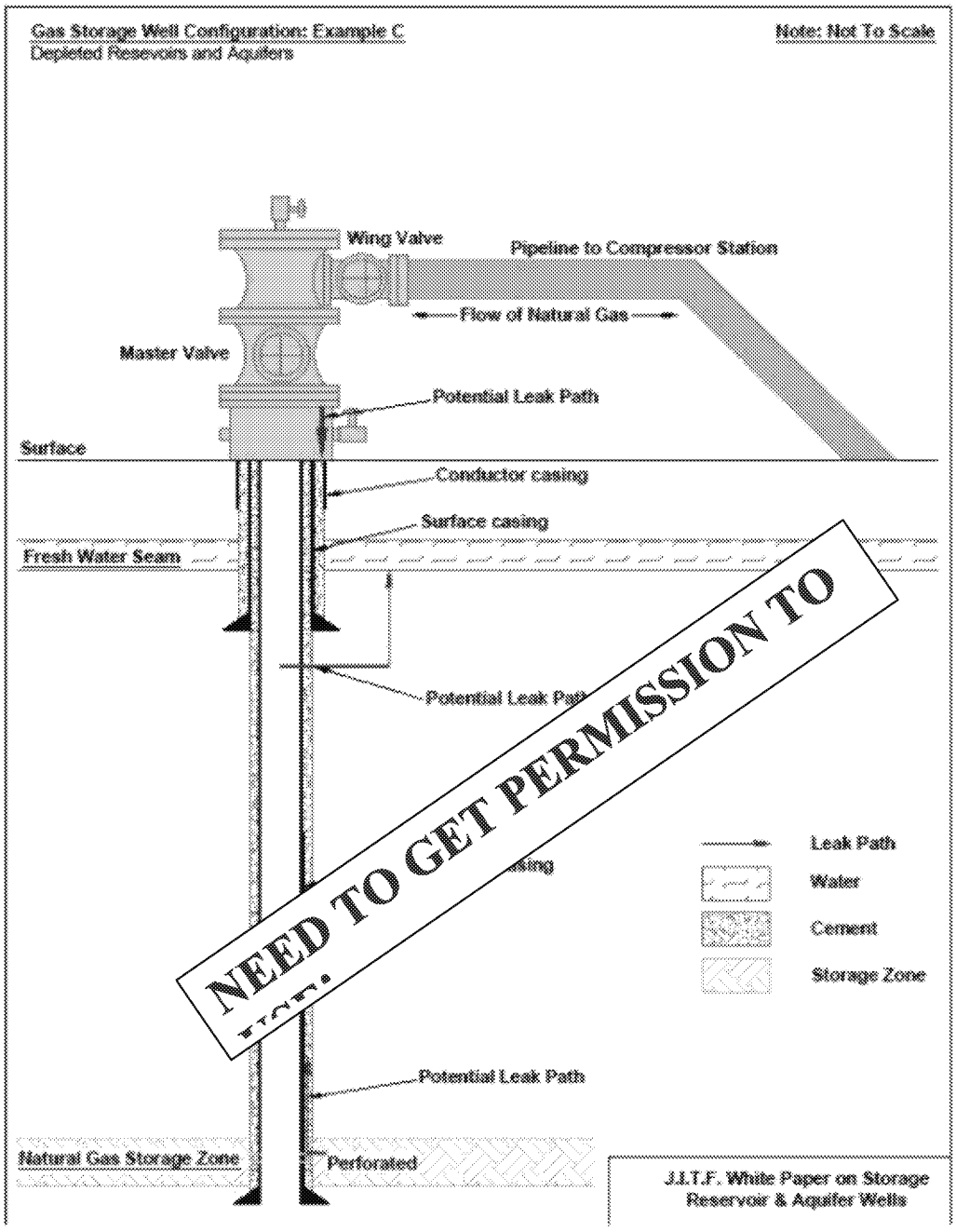

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2.5 Distribution

2.5.1 Distribution Mains/Services

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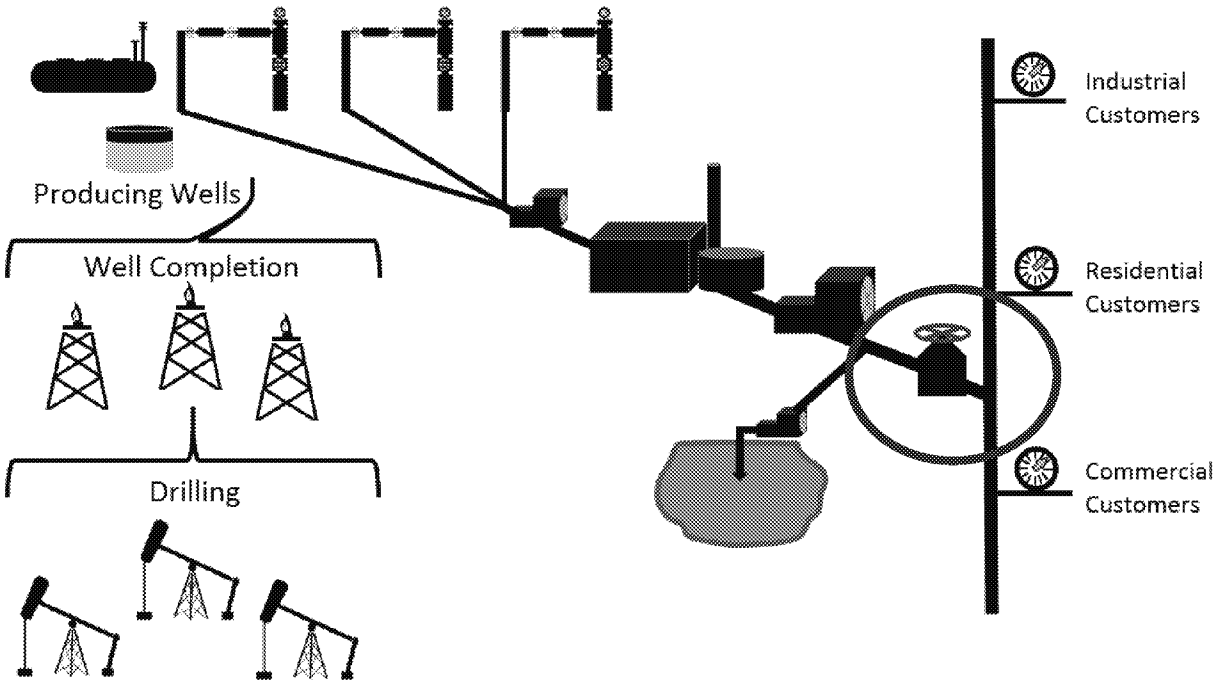

Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

2.5.1.1 Distribution

Distribution accounted for 6% of emissions in 2014 according to the 2016 EPA GHG Inventory.[1] Emissions are separated into those from transmission-distribution transfer stations (TDTS), metering/regulating stations, distribution mains, and services. Emissions from different types of mains are discussed including unprotected steel, protected steel, plastic, and cast iron. Also, we discuss three categories of end-user emissions including industrial, commercial, and residential. We include electricity production in industrial end-use for the distribution system.

[1] EPA U.S. GHG Inventory 2016

[2] Allen, et al. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States", PNAS 110, 2013

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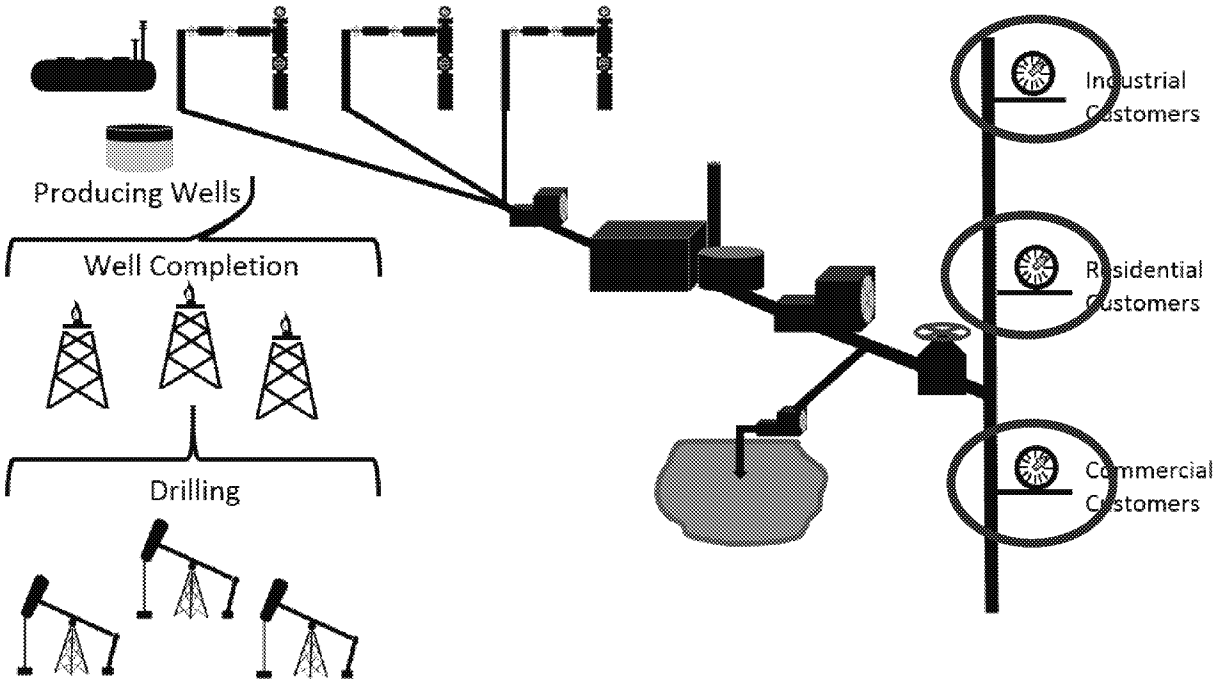
2.5.2 Regulators and meters



Source (GHG Inventory)	Natural Gas Systems (3-47)										
Stage (GHG Inventory)	Field Production					Processing	Transmission & Storage			Distribution	
Natural Gas Supply Chain	Drilling	Well Completion	Producing Wells	Gathering Lines	Gathering & Boosting Compressors	Gas Processing Plant	Transmission Compressor Stations	Transmission Pipeline	Underground Storage	Distribution Mains/Services	Regulators & Meters
Segment (Subpart W)	Onshore Production			Onshore Gathering & Boosting		Onshore Natural Gas Processing	Onshore Transmission Compression	Onshore Natural Gas Transmission Pipeline	Underground Natural Gas Storage	Distribution	

Activity	Activity Data	Emission Factor (Potential)[aa]	Calculated Potential Emissions (Mg)
Pipeline Leaks*			
Mains—Cast Iron	29,359 miles[a,1]	60.09 Mscf/mile-yr[c,bb]	33,976.2
Mains—Unprotected steel	58,520 miles[a,1]	44.72 Mscf/mile-yr[c,bb]	50,404.7
Mains—Protected steel	486,432 miles[a,1]	5.02 Mscf/mile-yr[c,bb]	47,061.8
Mains—Plastic	690,029 miles[a,1]	1.50 Mscf/mile-yr[c,bb]	19,905.5

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Services—Unprotected Steel	3,432,641 services[a,1]	0.75 Mscf/service[c,bb]	49,727.5
Services— Protected Steel	14,588,827 services[a,1]	0.07 Mscf/service[c,bb]	18,896.3
Services— Plastic	46,755,197 services[a,1]	0.01 Mscf/service[c,bb]	12,296.3
Services—Copper	935,595 services[a,1]	0.25 Mscf/service[b]	4,582.8
Meter/ Regulator (City Gates)*			
M&R >300	3,952 stations[c,d,2]	12.70 scfh/station[c,d,bb]	8,468.2
M&R 100-300	14,423 stations[c,d,2]	5.90 scfh/station[c,d,bb]	14,356.7
M&R <100	7,709 stations[c,d,2]	4.31 scfh/station[b]	5,605.7
Reg >300	4,321 stations[c,d,2]	5.15 scfh/station[c,d,bb]	3,754.4
R-Vault >300	1,501 stations[c,d,2]	0.30 scfh/station[c,d,bb]	76.0
Reg 100-300	13,071 stations[c,d,2]	0.85 scfh/station[c,d,bb]	1,874.6
R-Vault 100-300	3,473 stations[c,d,2]	0.30 scfh/station[c,d,bb]	175.8
Reg 40-100	39,225 stations[c,d,2]	0.97 scfh/station[c,d,bb]	6,419.5
R-Vault 40-100	20,573 stations[c,d,2]	0.30 scfh/station[c,d,bb]	1,041.3
Reg <40	16,633 stations[c,d,2]	0.13 scfh/station[b]	373.2
Customer Meters			
Residential	53,339,363 Outdoor meters[e]	77.31 scfy/meter[b,c]	79,424.1
Commercial/ Industry	5,611,121 meters[e]	505.40 scfy/meter[b,c]	54,619.1
Routine Maintenance			
Pressure Relief Valve Releases	1,264,340 milemain[a,1]	0.05 Mscf/mile[b]	1,217.6
Pipeline Blowdown	2,168,588 miles[b,2]	0.10 Mscfy/mile[b]	4,260.2
Upsets			
Mishaps (Dig-ins)	2,168,588 miles[b,2]	1.59 Mscfy/mile[b]	66,409.5

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Table XX: Fugitive methane emissions from natural gas distribution. Adapted from EPA ANNEX 3 Table A-138, Methodological Descriptions for Additional Source or Sink Categories[22]

2.6 Other

2.6.1 Abandoned Wells

Abandoned oil and gas wells are inactive wells that have been decommissioned due to economic reasons such as declining production. Many states require operators to plug the well bore of abandoned wells with cement to prevent fluid migration, but numerous wells remain unplugged because they were abandoned before regulatory requirements or orphaned by defunct operators. The number of abandoned wells is highly uncertain because of poor recordkeeping during early O&G development. Brandt et al. (2013) reports a range of one to three million abandoned wells in the United States. In Pennsylvania, where wells were first drilled in the late 19th century, Kang et al. (2016) estimates there are 450,000 – 700,000 abandoned wells in the state. Several recent studies have measured methane emissions from both plugged and unplugged abandoned wells. Kang et al. (2014) directly measured emissions from 19 abandoned wells in Pennsylvania with a mean emission rate of 11 g CH_4 h^{-1} $well^{-1}$. In a follow-up study of 88 Pennsylvania wells, Kang et al. (2016) reports that high emitting wells typically are unplugged gas wells or plugged wells in coal areas that vent coal seam gas for safety reasons. Additionally, high emitting wells were found to sustain their emission rates over two years of repeat measurements. Townsend-Small et al. (2016) measured emissions at 138 abandoned wells in the Denver-Julesburg (CO), Powder River (WY), Uintah (UT), and Appalachian (OH) basins. The mean emission rate was 1.4 g CH_4 h^{-1} well- but individual rates were highly skewed: 93.5% of wells had non-detectable emission rates and the highest emitting well (146 g CH_4 h^{-1}) was responsible for over three-quarters of measured emissions. Plugging appeared to be highly effective at reducing emissions with only 1 of 119 plugged wells having detectable emissions (mean = 0.002 g CH4 h-1) compared to 8 of 9 unplugged wells (mean = 10 g CH4 h-1). Stable isotope measurements indicate that the source of emitted methane includes coal seams in addition to the targeted natural gas formation. [PLACEHOLDER – PEKNEY ET AL (IN REVIEW)].

Although methane emissions from abandoned wells usually are much lower than active wells, the large number of abandoned wells could lead to substantial emissions. Townsend-Small et al. (2016) estimate abandoned wells contribute 1.9 – 4.3% of O&G methane emissions; for Pennsylvania, they may be responsible for 5 – 8% of anthropogenic methane emissions (Kang et

[22] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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al. 2016). EPA does not currently include estimates of abandoned well emissions in the U.S. Greenhouse Gas Inventory, but they have requested feedback on activity data and emissions data that could be used to estimate emissions from this source in future inventories.

2.6.2 Super Emitters

A large and growing set of data across the oil and gas supply chain shows that extremely high emitters are underrepresented in official greenhouse gas inventories. As a result, the official inventories described previously may underestimate the total volume of methane being emitted, and central estimates of emission rates (i.e. emission factors) may not capture the impact of the "fat tail" of skewed emissions distributions.

Extremely high emitters, commonly called "super-emitters", are infrequent. However, the impact of these few super-emitters on total emissions volume is disproportionately large. Across a variety of processes, operators, and regions, a small percentage of sites has been shown to account for a majority of emissions.

Official inventories have been shown to substantially underestimate total emissions, as emissions inventories are developed through extrapolating measurements made directly at emission sources to larger populations. The difficulty with this approach is obtaining a representative sample; extreme values can strongly influence average emissions, and very large sample sizes are required to ensure these high emitters are sufficiently characterized. Table 1 below summarizes studies that discuss the discrepancies between atmospheric (top-down) measurements of methane emissions and bottom-up measurements; the former are typically much larger than the latter, implying that actual emissions are likely much higher than bottom-up inventories.

Over time, increasing amounts of data have been collected that cumulatively get closer to a representative sample of emissions. Direct measurement studies that have found a small percentage of leaks accounting for a majority of emissions are described in Table 2 below. Scientists have found these heavy-tailed distributions across different geographies, operators, and processes. One recent paper (Brandt 2016) attempts to synthesize all prior existing direct measurements of methane leaks (including but not limited to the studies cited in the table below) to characterize the distribution more accurately. Brandt finds that heavy-tailed distributions are a pervasive characteristic of natural gas leak distributions, that the largest 5% of leaks are responsible for over 50% of the leaked methane from a given source category, and that lognormal distributions, which have sometimes been used to model heavy-tailed emission sources, still systematically underestimate the importance of the largest emitters.

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Top-Down vs. Bottom-Up Measurement Studies (Table 1)

Citation	Result
Miller, S. (2013). Anthropogenic emissions of methane in the United States. PNAS, 110 (50), 20018-20022. doi: 10.1073/pnas.1314392110	Regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR
Brandt, A. (2014). Methane leaks from North American natural gas systems. Science, 343 (6172), 733-735. doi: 10.1126/science.1247045	National emission inventory underestimates methane emissions by 14 Tg/yr (0.73 trillion cubic feet of methane, with a range of 7–21 Tg/yr)
Zavala-Araiza, D. (2015). Reconciling divergent estimates of oil and gas methane emissions. PNAS, 112 (51), 15597-15602. doi: 10.1073/pnas.1522126112	Measured oil and gas methane emissions are 90% larger than estimates based on the US Environmental Protection Agency's Greenhouse Gas Inventory and correspond to 1.5% of natural gas production.

Super-Emitter Studies (Table 2)

Citation	Segment	Sample Size	Result
Brandt, A. (2016). Methane leaks from natural gas systems follow extreme distributions. Environ. Sci. Technol., 50 (22), 12512–12520. doi: 10.1021/acs.est.6b04303	All	15,000 previous measurements	Aggregated 15,000 measurements from 18 prior studies, finding that 5% of leaks contribute over 50% of total leakage volume.
Frankenberg, C. (2016). Airborne methane remote measurements reveal heavytail flux distribution in Four Corners region. PNAS, 113 (35), 9734–9739. doi: 10.1073/pnas.1605617113.	Gas Producing Wells, Gas Processing Plants, Gas Gathering Lines, Gas Transmission Pipelines	250 point sources	10% of emitters accounted for ~50% of observed point source emissions, roughly ~25% of total basin emissions.
Lyon, D. (2016). Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites. Environ. Sci. Technol., 50 (9), 4877–4886. doi: 10.1021/acs.est.6b00705	Oil and Gas Producing Wells	8,000 well pads	Of 8,000 well pads, 4% of sites had high-emitting sources (detection threshold was 1-3 g/s).
Hendrick, M. (2016). Fugitive methane emissions from leak-prone natural gas distribution infrastructure in urban environments. Environmental Pollution, 213, 710-716. doi: 10.1016/j.envpol.2016.01.094	Distribution Mains	100 natural gas leaks from cast iron distribution main	7% of leaks contributed 50% of emissions measured.

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Omara, M. (2016). Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin. Environ. Sci. Technol., 50 (4), 2099-2107. doi: 10.1021/acs.est.5b05503	Gas Producing Wells	35 well pads	Of 13 unconventional routinely operating well pads, 23% of sites accounted for ~85% of emissions; of 17 conventional well pads, 17% of sites accounted for ~50% of emissions.
Zavala-Araiza, D. (2015). Reconciling Divergent Estimates of Oil & Gas Methane Emissions. PNAS, 112 (51), 15597–15602. doi: 10.1073/pnas.1522126112	Gas Producing Wells, Gas Processing Plants, Gas Transmission Compressor Stations	413 sites	2% of facilities are responsible for 50% of the emissions, 10% of facilities are responsible for 90% of the emissions.
Zimmerle, D. (2015). Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environ. Sci. Technol., 49 (15), 9374–9383. doi: 10.1021/acs.est.5b01669	Gas Transmission Compressor Stations, Gas Underground Storage	new measurements from 677 facilities, activity data from 922 facilities	Authors note that "equipment-level emissions data are highly skewed"
Lamb, B. (2015). Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environ. Sci. Technol., 49 (8), 5161–5169. doi: 10.1021/es505116p	Distribution Mains/Services, Regulators & Meters	257 pipe leakage measurements, 693 metering and regulator measurements	3 large leaks accounted for 50% of total measured emissions from pipeline leaks
Rella, C. (2015). Measuring emissions from oil and natural gas producing well pads in the Barnett Shale region using the novel mobile flux plane technique. Environ. Sci. Technol., 49 (7), 4742– 4748. doi: 10.1021/acs.est.5b00099	Oil and Gas Producing Wells	182 well pads	~6% of sites accounted for 50% of emissions, 22% of sites accounted for 80% of emissions
Yacovitch, T. (2015). Mobile Laboratory Observations of Methane Emissions in the Barnett Shale Region. Environ. Sci. Technol., 49 (13), 7889-7895. doi: 10.1021/es506352j	Oil and Gas Producing Wells, Gas Gathering & Boosting Compressor Stations, Gas Transmission Compressor Stations, Gas Processing Plants	188 emission measurements	7.5% of emitters contributed to 60% of emissions
Mitchell, A. (2015). Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results. Environ. Sci. Technol., 49 (5), 3219–3227. doi: 10.1021/es5052809	Gas Gathering & Boosting Compressors, Gas Processing Plants	114 gathering facilities, 16 processing plants	Of 114 compressor stations, 30% of sites were responsible for ~80% of emissions; of 16 gas processing plants, 45% of sites were responsible for ~80% of emissions.
Subramanian, R. (2015). Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol. Environ. Sci. Technol., 49 (5), 3252–3261. doi: 10.1021/es5060258	Gas Transmission Compressor Stations	47 compressor stations	Of 45 compressor stations, 10% of sites accounted for ~50% of emissions.
Kang, M. (2014). Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania. PNAS, 111 (51), 18173–18177. doi: 10.1073/pnas.1408315111	Abandoned Wells	19 abandoned wells	Of 19 abandoned wells, 3 had flow rates 3x larger than the median flow rate.
Allen, D. (2014). Methane Emissions from Process Equipment at Natural Gas Production Sites: Pneumatic Controllers. Environ. Sci. Technol., 49 (1), 633-640. doi: 10.1021/es5040156	Gas Producing Wells	377 pneumatic controllers	20% of devices accounted for 96% of emissions.

Allen, D. (2014). Methane Emissions from Process Equipment at Natural Gas Production Sites: Liquids Unloadings. Environ. Sci. Technol., 49 (1), 641-658. doi: 10.1021/es5040156r	Gas Producing Wells	107 wells with liquids unloading	Without plunger lift, 20% of wells accounted for 83% of emissions; with plunger lift and manual, 20% of wells accounted for 65% of emissions; with plunger lift and automatic, 20% of wells accounted for 72% of emissions.

2.6.3 Offshore Facilities

Activity Equipment	Emission Factor	Activity Data	Emissions (Bcf/yr)	Emissions (kt/yr)
Vented Emissions				168.1
Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	16,552 scfd CH4/platform[q]	1,447 No. of shallow water oil platforms[l,4]	8.739	168.1
Offshore Platforms, Deepwater oil, fugitive, vented, and combusted	93,836 scfd CH4/platform[q]	29 No. of deep water oil platforms[l,4]	1.001	19.3

Table XX: Fugitive methane emissions from oil field operations. Adapted from EPA ANNEX 3 Table A-127, Methodological Descriptions for Additional Source or Sink Categories[23]

While this effort does not include offshore facilities within its scope, there is need for further analysis and research into the offshore subsector. There are programs and resources currently available to begin this effort, for example the Gulf Offshore Activity Data System program (GOADS) is a study conducted by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). This study is set up to comply with 30 CFR 250.302-304 which requires that petroleum and natural gas production platforms located in the Federal Gulf of Mexico to report their activities to BOEMRE once every three to four years. The activities reported include:

Emissions sources

Volumes of throughputs from some equipment

[23] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2014 https://www.epa.gov/sites/production/files/2016-04/documents/us-ghg-inventory-2016-annex-3-additional-source-or-sink-categories-part-a.pdf

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Fuel consumption by combustion devices

Parametric data from some emission sources like glycol dehydrators

While this requirement does not apply to all U.S. offshore oil and natural gas operation, it may be assessed and evaluated for strengths and opportunities. This ITRC team recommends that a future project include offshore oil and gas operations equipment inventory and emissions analysis.

2.6.4 Surface Casing Venting

Gathering lines

Pneumatic devices

Well pad compressors?

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3 REGULATIONS

3.1 Objectives & Introduction

This section provides an overview of present existing and proposed laws and regulations of federal, state and local governments in the United States, as well as some international governments, pertaining to methane emissions from the onshore oil and gas sector, with a specific focus on what is often referred to as "fugitive" emissions or leaks from equipment. These regulations can be placed under the general umbrella term of "Leak Detection and Repair (LDAR)" requirements. Some of these regulations concurrently regulate volatile organic compounds (VOCs) with methane and so the regulation applies to all hydrocarbons (methane + VOCs) in the fugitive emissions or gas stream. Methane is considered a greenhouse gas (GHG) while VOCs contribute to the formation of ground-level ozone, which is a respiratory irritant. Some VOCs are also toxic to human health, such as benzene. This section will differentiate between oil and gas fugitive emission or LDAR regulations that apply to methane only, VOCs only, and methane + VOCs. Note that regulations that only apply to VOCs do have the co-benefit of reducing methane emissions as well since all emissions in the gas stream are addressed through leak repair. In addition, this section identifies regulatory barriers and constraints on the approval, use and adoption of new or innovative fugitive emission detection technologies, including those specific to methane, and identifies regulatory concerns and considerations in this regard, as well as areas of opportunity.
Regulation of fugitive emissions from the oil and gas sector, particularly in the United States, is broken down by the various segments of the sector from drilling and production through transmission and distribution (please see the Characterization section for more details on the oil and gas sector segments). U.S. federal regulatory agencies that oversee fugitive emissions or equipment leaks from the oil and gas sector include the Environmental Protection Agency (EPA), Bureau of Land Management (BLM), which is part of the Department of Interior, and the Pipeline and Hazardous Materials Safety Administration (PHMSA), which is part of the Department of Transportation. The EPA and BLM provide regulatory oversight for the production and processing segments of the sector, while PHMSA oversees transmission and distribution (pipelines). The basis for these regulations vary from public health and environmental protection (EPA) to resource conservation (BLM) and safety (PHMSA).

At the state level, delegated authority for these regulations, such as those from EPA and PHMSA, is given to the states to implement, which is typically accomplished through a state's environmental or air quality department for production and processing and public utility commission (PUC) or other similar agency for transmission and distribution. However, states can also adopt their own regulations that go above and beyond federal requirements and several have done so in the last number of years, including Colorado, Pennsylvania, Ohio and California. A number of these states have specifically targeted methane as part of their regulations, with a focus primarily on the production, processing and storage segments of the oil and gas sector.

At the transmission and distribution level, a state agency participating in PHMSA's pipeline safety program is required to adopt federal pipeline safety regulations. In addition, a state agency may issue additional or more stringent standards concerning intrastate pipelines as long as they are compatible with federal regulations.

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Local governments can also adopt their own fugitive emissions regulations and/or have delegated authority to implement federal or state requirements. This is most often found in California where local air quality management districts implement federal and state rules, and have also adopted their own VOC LDAR regulations, helping to meet federal air quality standards.

Table 1 summarizes oil and gas fugitive emission regulations at the international, federal, state and local levels. A more detailed summary of specific fugitive emission regulations that target or include methane and/or allow use of approved alternative leak detection technologies is provided below.

3.2 United States – Federal Fugitive Methane Emission Regulations

3.2.1 Environmental Protection Agency

3.2.1.1 New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector Subpart OOOOa [Citation*: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942]*

EPA's NSPS Subpart OOOOa ("NSPS OOOOa"), which is a revision to NSPS OOOO, became effective on August 2, 2016 and applies to facilities in the drilling, production and processing segments of the onshore oil and gas sector that commenced construction, modification or reconstruction after September 18, 2015. As of the publication of this document, the status of NSPA OOOOa, particularly in regard to the leak detection and repair (LDAR) requirements for fugitive emissions, is uncertain (*note here or reference to current status).* However, a summary of the LDAR requirements as they currently stand will be provided.

NSPA OOOOa regulates methane and VOCs from a variety of sources, including fugitive emissions. NSPA OOOOa also includes a provision for approval of emerging or alternative technologies for fugitive emissions detection. The summary below provides an overview of the fugitive emissions/LDAR and emerging technology sections of the rule.

Note: On July 3, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's 90-day stay of portions of the 2016 New Source Performance Standards for the Oil and Gas Industry which included the LDAR provisions. EPA is considering its options in light of the court's opinion. On July 7, 2017, EPA moved the court to recall its mandate in order to provide EPA with the standard short period of time in which to evaluate its options before the court's decision becomes effective. This motion is pending before the court. The court also emphasized that nothing in its opinion limits EPA's authority to reconsider the oil and gas standards and to proceed with its June 16, 2017 proposed two-year stay of certain requirements in the rule (including LDAR). EPA will take comment on those proposals until August 9, 2017.

On July 13, 2017, the U.S. Court of Appeals for the D.C. Circuit ordered a recall for 14 days its decision vacating the stay of EPA's June 3, 2016 final rule establishing New Source Performance Standards for the oil and natural gas industry (81 Fed. Reg. 35,824) on July 3. The recall was in response to EPA's July 7 motion, which asked the court to recall the ruling in order to give EPA time to "determine whether to seek panel rehearing, rehearing en banc, or pursue other relief."

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Clean Air Council v. Environmental Protection Agency, No. 17-1145, July 3, 2017 (United States Court of Appeals for the District of Columbia Circuit)

3.2.1.2 NSPS Subpart OOOOa Requirements for Leak Detection & Repair (LDAR) *(Reference to Federal Register)*

NSPS OOOOa imposes standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emission components at well sites (including centralized tank batteries) and compressor stations (gathering & boosting as well as transmission & storage). Semiannual or quarterly monitoring and repair of equipment and components that may leak or release fugitive emissions at these facilities is required.

Leak monitoring must be conducted using optical gas imaging (OGI), which is often referred to as an infrared (IR) camera, and repairs must be made if any emissions are seen or observed. EPA determined OGI, which can see emissions not visible to the naked eye, to be what is known as the Best System of Emissions Reduction (BSER) for fugitive emissions from well sites and compressor stations, which means OGI meets the standard of performance established by EPA for achieving the necessary emission reductions at these facilities. However, OOOOa also specifies that Method 21 (M21), which quantifies leaks at a concentration level in parts per million (ppm), may be used as an alternative monitoring method to OGI, which can only detect emissions, but not quantify them. If M21 is used, then component repair must be conducted if the leak concentration level is 500 ppm or greater. Repairs must be made within 30 days of finding fugitive emissions and a resurvey of the repaired component must be made within 30 days of the repair using OGI or M21 at a repair threshold of 500 ppm. Monitoring and repair records must be maintained and submitted with semi-annual reports to EPA or the administering agency.

If OGI is used, a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area must be developed and implemented. Owners and operators develop a plan that describes the facilities subject to monitoring in that area, including descriptions of equipment, plans for how monitoring will be conducted, etc., that apply to all similar facilities. This allows owners and operators to develop a monitoring plan for groups of similar facilities within an area for ease of implementation and compliance. These plans must include a typical "observation path" that is focused on the field of view of the OGI instrument being used(not the physical location of the OGI operator) to ensure all components get monitored. The intent is to allow for the use of all types of OGI instruments (e.g., mounted, handheld or remote controlled) for monitoring. The observation path description may be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI instrument's monitoring path.

3.2.1.3 Provision for Emerging Technology

Fugitive emissions monitoring and repair is a work practice standard, as allowed under the Clean Air Act (CAA) *(reference here).* A work practice standard is an emission limitation (BSER) that

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is not necessarily in a numeric format, such as the visualization of fugitive emissions using OGI. The Clean Air Act also allows approval an alternative means of emission limitation (AMEL) for a work practice standard if it can be proven that an equal reduction in emissions will be achieved through that alternative *(reference here)*. To that end, and because methane and VOC leak detection technology has been undergoing continuous and rapid development and innovation, potentially yielding, for example, continuous emissions monitoring technologies, NSPS OOOOa includes a process for EPA to permit the use of an innovative technology for reducing fugitive emissions at well sites and/or compressor stations *(reference here)*.

Specifically, *owners or operators* may submit a request to the EPA for an "alternative means of emission limitation" where a technology has been demonstrated to achieve a reduction in emissions at least equivalent to the reductions achieved under the OGI work practice of NSPS OOOOa.

To facilitate the application and review process, NSPS OOOOa identifies information that must be included in the AMEL application in order for EPA to evaluate the emerging technology, which includes:

- a description of the emerging technology and the associated monitoring instrument or measurement technology;
- a description of the method and data quality used to ensure the effectiveness of the technology;
- a description of the method detection limit of the technology and the action level at which fugitive emissions would be detected;
- a description of the quality assurance and control measures employed by the technology;
- field data (covering a period of at least 12 months and contemporaneously conducting M21 or OGI leak detection at prescribed frequency) that verify the feasibility and detection capabilities of the technology; and
- any restrictions for using the technology.

This process allows for the approval and use of any currently emerging technology or any technology developed in the future that can demonstrate methane and VOC emission reductions at levels that are at least equivalent to the reductions achieved when using OGI or M21 for fugitive emissions monitoring. This process also allows for the use of alternative fugitive emissions monitoring approaches such as periodic, continuous, fixed, and mobile (including aerial), or a hybrid approach.

Consistent with the AMEL provision of the CAA, any application will be publicly noticed in the Federal Register, including all required information for evaluation. The EPA will provide an opportunity for public hearing and comment on the application and on intended action the EPA might take. The EPA then makes a final determination on the AMEL application within six

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months after the close of the public comment period and publishes its determination in the Federal Register. If the final determination is denial of the application, the EPA will provide reasoning for denial and recommendations for further development and evaluation of the emerging technology, if appropriate. If an AMEL is granted approval, then it is specific to a single facility and applicant *(Cindy – need clarification on this).*

Note that in order for a technology to be considered for AMEL under OOOOa it must be capable of detecting methane and VOCs, or be able to demonstrate equivalent reductions of methane and VOCs if not all compounds can be detected.

As of the date of this document, EPA had not received any AMEL applications under OOOOa.

Citation: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942 [cite again here]

3.2.1.4 Greenhouse Gas Mandatory Reporting Rule

The Greenhouse Gas Mandatory Reporting Rule (GHGMR) was published by EPA in October 2009 and went into effect in January 2010. The rule requires annual reporting of greenhouse gases (GHG), including methane, from large emission sources across a range of industrial categories, including the oil and gas sector. The purpose of the rule, as noted by EPA *(https://www.epa.gov/sites/production/files/2014-09/documents/ghgrp-overview-factsheet.pdf)*, is to provide for a "collection of comprehensive, nationwide emissions data [that] is intended to provide a better understanding of the sources of GHGs and to guide development of policies and programs to reduce emissions." Thus, unlike NSPS OOOOa, actual emission reductions are not required under GHGMR, only calculation and reporting of emissions. Additionally, VOCs are not covered under GHGMR since they are not GHGs.

One of the options in GHGMR for estimating emissions from equipment leaks ("fugitive emissions") in the oil and gas sector is an equipment leak survey. Equipment leak surveys are required for certain component types, and reporters must use one of the monitoring methods specified in the rule to conduct those surveys. In recent revisions to the rule, effective January 1, 2017 *(reference here)*, new monitoring methods for detecting leaks from equipment in the petroleum and natural gas source category were added to be consistent with the leak detection methods in the New Source Performance Standards (NSPS) for the oil and gas industry. These revisions were the result of a review of existing requirements in the GHGMR to address potential gaps in coverage and to improve monitoring methods to ensure high quality data reporting. EPA also received direction to explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions in the oil and gas sector.

Subpart W of the GHGMR specifies the monitoring methods that may be used for equipment leak surveys, which include Optical Gas Imaging, Method 21, Infrared Laser Illuminated Instruments and Acoustic Leak Detection Devices. The rule specifies how leaks are to be measured for each monitoring method used. Additionally, Subpart W allows for temporary use of alternative monitoring methods not specified in the rule for certain facilities and operations.

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3.2.1.5 Alternative Work Practice (AWP) to Method 21 for Leak Detection and Repair

Numerous EPA air emissions standards, including those for segments of the oil and gas sector, require a specific work practice, otherwise known as Method 21, for equipment leak detection and repair (LDAR) of fugitive VOC emissions. On April 6, 2006, the EPA proposed a voluntary alternative work practice (AWP) for LDAR using optical gas imaging (OGI), which was a newly developed technology at the time. The AWP was eventually finalized and adopted in 2008 and allows for the voluntary use of OGI in place of Method 21 for any rule that requires LDAR for fugitive VOCs. The AWP still requires annual monitoring using Method 21 but all other periodic monitoring may be performed with OGI.

Note that in NSPS OOOOa, OGI is actually the preferred work practice for LDAR at well sites and compressor stations and Method 21 is the alternative work practice. However, for gas processing plants subject to OOOOa, OGI is still considered the AWP for purposes of LDAR and Method 21 is the preferred work practice.

The AWP was the first time EPA allowed an alternative to Method 21 for LDAR and, in essence, opened the door for potential consideration of other innovative leak detection technologies or methods.

3.2.2 Pipeline and Hazardous Material Safety Administration (PHMSA) - Federal Gas Pipeline Safety Regulations

The safety of natural gas pipeline systems are regulated by the United States Department of Transportation's (USDOT) Pipeline and Hazardous Material Safety Administration (PHMSA). PHMSA directly administers the pipeline safety program and develops and enforces requirements for interstate and intrastate pipelines. These regulations are written to ensure safety in the design, construction, testing, operation, and maintenance of pipeline facilities and in the siting, construction, operation, and maintenance of liquefied natural gas (LNG) facilities. PHMSA ensures compliance with regulations through operator inspections, enforcement actions, and accident investigations.

PHMSA also administers grant-in-aid funding to States that provides reimbursement for up to 80% of qualified expenses incurred by the State program for pipeline inspection activities. Each participating State delegates responsibility for pipeline safety to a State agency. State agency duties normally consist of operator inspections, compliance and enforcement, safety programs, accident investigations, pipeline construction inspections, and record maintenance and reporting.

The State agency may adopt additional or more stringent standards for intrastate pipeline facilities provided such standards are compatible with Federal regulations.[1] Under an *agreement* or *interstate* agent agreement, the State agency assumes inspection responsibility for facilities and reports probable violations to PHMSA for compliance action.[2]

3.2.2.1 PHMSA Natural Gas Pipeline Regulations

PHMSA requires operators of pipeline facilities to follow regulations applicable to the commodity being transported. For natural gas, which is mostly methane, the requirements are

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found in Code of Federal Regulations 49 Part 192 (49 CFR Part 192) – Transportation of Natural and Other Gasses by Pipeline, and include leak monitoring or survey requirements, which will be discussed here.

An important aspect of the natural gas pipeline safety regulations is that for each operations and maintenance technical requirement found in Part 192, there must be a corresponding operator procedure for meeting that requirement. Operators are required to follow both the technical requirements found in Part 192 and the procedures it has developed for meeting those requirements, including leak monitoring and repair. It is also important to note that the requirements found in Part 192 are considered minimum requirements, meaning each operator can, and often does, have procedures that are more prescriptive and more stringent than the requirements found in Part 192.

3.2.2.2 Operations and Maintenance

Each pipeline operator is required to prepare and follow a manual of written procedures for conducting operations and maintenance activities for each pipeline, including leak monitoring and repair.

- Each transmission line and distribution main must be surveyed at regular intervals for indications of leaks using leak detection equipment and hazardous leaks must be repaired promptly. *(Need explanation or definition here on what is considered a "hazardous leak").*

- Compressor stations, pressure regulating stations, and valves along pipelines also need to be tested and inspected at regular intervals to ensure that the equipment is operating as designed and able to be used when needed. These testing and inspection activities normally include leak detection and repair.

3.2.2.3 Leak Detection

As noted, Part 192 requires leakage surveys be conducted using "leak detector equipment", which is a performance-based requirement, meaning that any equipment capable of detecting all leaks in gas distribution or transmission systems may be used. The regulations do not mandate the use of any specific type of leak detection equipment and since natural gas is primarily methane, equipment that can only detect methane is acceptable. However, it is imperative that procedures exist for proper use and calibration of the equipment. In addition, since State pipeline safety regulations are allowed to be more specific and more stringent than federal regulations, a state may adopt leak detection equipment requirements of its own for conducting leakage surveys in its specific jurisdiction.

Examples of acceptable natural gas pipeline leak detection equipment or methods include *(need examples here)…*

Another important aspect of pipeline safety related to leak surveys is integrity management (IM). Transmission and distribution operators are required to have IM programs to evaluate and address risks on their pipelines, which include using performance metrics to measure the number

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of hazardous leaks either eliminated or repaired, and the total number of leaks either eliminated or repaired, categorized by cause.

3.2.3 Bureau of Land Management (BLM)

3.2.3.1 BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR Parts 3100, 3160 and 3170)

The BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation rule ("Waste Prevention rule") was proposed in 2016 and became effective on January 17, 2017. As of the publication of this document, the status of the Waste Prevention rule is uncertain (*note here or reference to current status).* However, a summary of the requirements as they currently stand will be provided. The rule includes LDAR requirements for existing and new facilities located on BLM-managed lands, which includes semi-annual leak monitoring at well sites (including oil wells that also produce natural gas and produced water handling facilities) and quarterly monitoring at compressor stations.

3.2.3.1.1 Alternative Technology Provisions

The Waste Prevention rule applies to hydrocarbon emissions (methane + VOCs) and, similar to NSPS OOOOa, allows for the use of OGI or Method 21 for leak monitoring, as well as approved alternatives. The rule specifies that any person may request approval of an alternative monitoring device and protocol (e.g. a device that monitors continuously, but is less sensitive than optical gas imaging, might achieve results equivalent to optical gas imaging due to the gas savings from early detection) by submitting a Sundry Notice to BLM that includes the following information:

- Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function;
- The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded;
- Records and data from laboratory and field testing, including but not limited to performance testing;
- A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring;
- Tracking and documentation procedures; and
- Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.

The BLM may approve an alternative monitoring device and associated inspection protocol if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks

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compared with OGI semiannual/quarterly monitoring. The BLM will provide public notice of a submission for approval and may approve an alternative device and monitoring protocol for use in all or most applications (i.e. once approved, any operator could use it, which differs from NSPS OOOOa), or for use on a pilot or demonstration basis under specified circumstances that limit where and for how long the device may be used. The BLM will post on its web site a list of each approved alternative monitoring device and protocol, along with any limitations on its use. The BLM intends that the decision to approve the use of an alternative monitoring device would be made only at the national level, by the Director, Deputy Director, or an Assistant Director, as, once approved, the alternative monitoring device could be used at any facility subject to BLM requirements.

In addition to the alternative monitoring device option, the Waste Prevention rule also includes a provision for approval of an alternative instrument-based leak detection program. The BLM may approve an operator's request to use an alternative instrument-based leak detection program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring. For example, an operator might propose a program that included more frequent inspections for some sites and less frequent inspections for others, or an operator may be able to deploy an alternative leak detection device or system, approved by the BLM, on a continuous basis and achieve results that would allow for less frequent inspections using optical gas imaging or Method 21. In essence, the alternative leak detection program allows for flexibility to potentially combine use of an alternative leak detection monitoring device with an already-approved monitoring device or method under the rule (OGI and Method 21).

The operator must submit its request for an alternative leak detection program through a Sundry Notice that includes the following information:

- A detailed description of the alternative leak detection program, including how it will use OGI and/or Method 21, along with sensory leak detection methods (audio/visual/olfactory or AVO), and an identification of the specific instruments, methods and/or practices and elements of the approach;
- The proposed monitoring protocol;
- Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;
- A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to OGI or Method 21 with AVO semiannual/quarterly monitoring;
- A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and
- Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

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Unlike the alternative monitoring device approval, a BLM State Director could approve an alternative leak detection program if the alternative program is determined to achieve equal or greater reduction of gas lost through leaks compared to the leak detection program required under the rule. However, the rule does not allow other operators to use an alternative leak detection program requested by and approved for a specific operator, as the results may not be transferable.

The BLM may also approve an alternative leak detection program if the operator demonstrates, and the BLM agrees, that compliance would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease. The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and hydrogen sulfide content), revenues derived from production, and royalty payments on production over the next fifteen years or the life of the operator's lease as part of the alternative leak detection program request.

Finally, the Waste Prevention rule also allows an operator to choose to comply with the EPA fugitive emissions monitoring requirements in NSPS OOOOa in lieu of complying with the LDAR provisions in the Waste Prevention rule for all sites and equipment not already deemed in compliance with the BLM LDAR provisions. This provision allows an operator with some facilities subject to NSPS OOOOa and the Waste Prevention rule and other facilities only subject to the Waste Prevention rule to apply a single leak detection regime to all of their facilities, rather than complying with NSPS OOOOa for some facilities and the BLM requirements for others.

If an operator decides to comply with NSPS OOOOa, they must also look for leaks on tank covers and closed vent systems (whose inspection requirements reside in a different part of OOOOa than the LDAR provisions)

As of the date of this document, the BLM State Director for New Mexico has approved the use of Tunable Diode Laser Absorption Spectroscopy (TDLAS) as part of an alternative instrument-based leak detection program *(need more details on this).*

Federal Register Notice - https://www.gpo.gov/fdsys/pkg/FR-2016-11-18/pdf/2016-27637.pdf?utm_campaign=subscription%20mailing%20list&utm_source=federalregister.gov&utm_medium=email

3.2.4 State Specific Laws and Regulations (Government Fugitive Emission/LDAR Regulations)

In addition to federal requirements, some state governments have adopted their own fugitive emission/LDAR regulations for the oil and gas sector that supplement or go beyond federal requirements. Some of these regulations target or include methane and some do not. Additionally, some of the regulations allow for the approval of innovative or alternative leak detection technologies, while others mandate that only certain types of technologies or methods

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may be used. A summary of specific state fugitive emission/LDAR regulations is provided below.

ITRC conducted a survey of state and local governments concerning fugitive emission/LDAR regulations for the oil and gas sector that was coordinated by ITRC's state Point of Contacts (POCs). Information obtained through that survey helped inform what is included in this section.

3.2.4.1 State Government Regulations that apply to Fugitive Methane Emissions

3.2.4.1.1 California – Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

California is unique among states to have the only oil and gas regulation focused exclusively on methane. California's "Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities" regulation, which became effective January 1, 2017 and requires full compliance by December 31, 2018, is aimed at reducing statewide methane emissions from new and existing facilities in the oil and gas production, processing, and storage sectors, and from transmission compressor stations. Its requirements include:

- Vapor collection on uncontrolled separators and tanks;
- Leak Detection and Repair (LDAR) at facilities not already covered by local air districts' VOC rules;
- LDAR monitoring at underground gas storage facilities, as well as ambient air monitoring and daily or continuous wellhead monitoring;
- Emissions standards for both reciprocating and centrifugal compressors, in addition to LDAR; and
- No-bleed requirements for pneumatic devices and pumps.

The statewide methane regulation's LDAR provision requires quarterly inspections using detection and measurement instruments compatible with US EPA Method 21, with the final leak standard being 1,000 ppmv. Currently, there is no alternative leak detection method or technology allowed, but the California Air Resources Board (CARB), which administers the rule, may consider allowing alternative methodologies in future amendments if, for example, Optical Gas Imaging technology evolves to allow quantification in addition to detection. However, the underground gas storage provision does allow for different and more innovative instrument technologies. This provision includes daily or continuous leak monitoring at the wellheads as well as ambient air monitoring and the use of OGI in the case of a well blowout.

California has eight oil and gas producing local air districts that have their own LDAR rules -- some for decades -- to reduce VOC emissions from oil and gas operations. California used these district VOC rules as a starting point for its methane regulation's LDAR provision. For the most part, the district and CARB LDAR provisions are similar, but there are some differences. For

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example, inspections may be less frequent in district rules, and the leak concentration standards vary. The district LDAR rules typically exempt components at oil and gas facilities that exclusively handle gas, vapor, or liquid with a VOC content of 10 percent by weight or less. It is these components that the CARB regulation covers. District VOC rules cover about 80 percent of all the components in the sector.

3.2.4.2 State Government Regulations or Permits that apply to Fugitive Methane + VOC Emissions

3.2.4.2.1 Colorado – Regulation No. 7

In 2014, Colorado's Air Quality Control Commission (AQCC) adopted updates to Regulation No. 7 that focus on reducing methane and VOC emissions from the upstream oil and gas sector, which includes well production facilities, natural gas compressor stations, and natural gas processing plants (https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_1.pdf).

The regulation includes LDAR provisions for well production facilities and compressor stations that require one-time or periodic monitoring for leaks from components using an Approved Instrument Monitoring Method (AIMM), which may be OGI, EPA Method 21 or other Division-approved instrument based monitoring device or method. An AIMM must be capable of detecting the emissions subject to the regulation, which include methane and VOCs. If OGI is used as AIMM, a leak is defined as any detectable emissions observed using the OGI instrument. If Method 21 is used, a leak is defined as either a hydrocarbon concentration of 2,000 ppm or 500 ppm, depending on the facility type and when it was constructed.

There are also separate requirements specific to atmospheric storage tanks that store hydrocarbon liquids, which includes condensate, oil and produced water, known as Storage Tank Emission Management (STEM). STEM requires that all storage tank hydrocarbon emissions must be routed to air pollution control equipment. To help accomplish this, a STEM plan has to be developed and implemented to identify technologies, practices and strategies to prevent the release of tank emissions to atmosphere. Additionally, periodic AIMM monitoring and audio, visual and olfactory (AVO) inspections of affected tanks must be conducted to check for the release of emissions. Any detectable tanks emissions must be immediately addressed or repaired.

As of the date of this document, Colorado has proposed requiring periodic AIMM inspections of gas-actuated pneumatic controllers in the state's ozone non-attainment area under Regulation No. 7 to find and address controllers in need of repair, adjustment or replacement. ***Placeholder language.***

Colorado's Air Pollution Control Division ("APCD") has developed guidance and an application form for technologies or methods seeking to gain approval as AIMM under Regulation No. 7 (https://www.colorado.gov/pacific/cdphe/AIMM). The guidance specifies that a technology or method must not be in the prototype or development phase in order be considered and be may be approved as either a quantitative or non-quantitative AIMM. A quantitative AIMM must be able to detect and measure the hydrocarbons in the emissions stream, while a non-quantitative AIMM only needs to detect the hydrocarbons in the emissions stream. The criteria used for evaluating

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an AIMM application include the operating requirements and limitations of the technology or method, including the emissions detection threshold and anything that impacts detectability, ability to pinpoint the specific source of emissions or leak location, calibration and maintenance requirements, data logging and recordkeeping capabilities, training or certification for use and operation, and testing results (lab and/or field), including any comparative monitoring with OGI and/or Method 21. If a technology or method is approved as AIMM, APCD issues an approval letter to the applicant that outlines the conditions or requirements for use of the AIMM and posts the approval letter on the APCD's AIMM web page. Once an AIMM is approved, it may be used by anyone to meet Regulation No. 7 requirements.

As of the date of this document, two technologies or methods had been approved as AIMM by APCD *(will need to update this accordingly)*.

3.2.4.2.2 Pennsylvania – General Permit 5 and Permit-Exemption Category No. 38

Pennsylvania's General Permit 5 (GP-5) is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are that are classified as minor sources of air pollution.

GP-5 was first approved by the Pennsylvania Department of Environmental Protection (DEP) on February 1, 2013. (http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf) An owner or operator of a facility subject to GP-5 must conduct monthly leak monitoring at the facility on a monthly basis using AVO methods and on a quarterly basis using an OGI camera or other leak detection monitoring device approved by the DEP. A leak is defined as any release of gaseous hydrocarbons detected by the OGI camera or through AVO methods.

Permit-exemption category no. 38 (PE #38) was finalized on August 10, 2013 and applies to unconventional wells, wellheads, and associated equipment and requires an LDAR program within 60 days after a well is put into production, and annually thereafter, as a condition of meeting the permit-exemption. The LDAR program must utilize an OGI camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2%, or other leak detection monitoring devices approved by the DEP. LDAR must be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquid service.

As of the date of this document, DEP has not published any guidance on the application and evaluation procedures for "other leak monitoring devices" to gain approval for use under GP-5 and PE #38. A Frequently Asked Questions (FAQ) document published by DEP for GP-5 and PE #38 states that an alternate leak detection technology could be used if "it is approved by DEP following a case-by-case evaluation of the device or technology." (http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/FAQ_GP-5_AND_EXEMPTION_CATEGORY_NO_38.pdf)

As of the date of this document, no requests for approval of alternate leak detection technologies or methods had been submitted to the DEP.

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3.2.4.2.3 Ohio – General Permits 12.1, 12.2 and 18.1

The Ohio Environmental Protection Agency (OH EPA) approved two types of general permits for high volume horizontal hydraulic fracturing, oil and gas well site production operations (General Permits 12.1 and 12.2) in May 2014 and a general permit for equipment leaks from natural gas compressor stations (GP 18.1) in early 2017 (http://www.epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits)

Each of these permits require development and implementation of an LDAR program for equipment that has the potential to leak (pumps, compressors, pressure relief devices, connectors, valves, flanges, intermittent/snap-action pneumatic controller, vents, covers, any bypass in a closed vent system, and each storage vessel) using an OGI camera or EPA Method 21. Leak monitoring must be conducted within 60 or 90 days of startup and quarterly thereafter. GP 12.1 and 12.2 allow the monitoring frequency to be reduced after the first four quarters of monitoring if the leak rate of the equipment at a facility is determined to be less than 2.0%. A leak is defined as any detectable emissions with the OGI camera or concentrations between 500 – 10,000 ppm depending on the component if Method 21 is used.

3.2.4.2.4 New York regulations (currently pending)

3.2.4.3 State Government Regulations or Permits that apply to Fugitive VOC Emissions

3.2.4.3.1 Utah – General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery

In June 2014, the Utah Department of Environmental Quality (UTDEQ)issued "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery". [Citation https://deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf[]. This General Approval Order (GAO) requires LDAR for affected equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) at a well site and/or tank battery using OGI, EPA Method 21 or tunable diode laser absorption spectroscopy (TDLAS). Inspection or monitoring frequency is based on projected throughput of crude oil and condensate in the storage tank(s) on site, or annually if no storage tanks are on site. The monitoring frequency may be reduced at sites with tanks that have large throughputs if no leaks are found over a certain period.

A leak is defined as a reading of 500 ppm with a Method 21 analyzer or TDLAS, or visible/detectable emissions with OGI.

Although the GAO does not specifically indicate that it covers methane emissions, UTDEQ estimated methane reductions that would be achieved through implementation of the GAO *(ref. "Comparison of State Leak Detection and Repair Programs, 4/20/16, EC/R Inc.).*

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3.2.4.3.2 Wyoming – Air Quality Standards & Regulations, Chapter 8

In June 2015, the Wyoming Department of Environmental Quality (WYDEQ) finalized revisions to Chapter 8 of the Wyoming Air Quality Standards and Regulations (WAQSR). The revisions include a requirement in Section 6 for multiple or single well production facilities and all compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOCs in the Upper Green River Basin ozone nonattainment area to develop and implement an LDAR programby January 1, 2017.\. Operators must monitor components quarterly using EPA Method 21, an OGI/IR camera, or other instrument based technology or method, along with AVO inspections.

The rule also requires that companies submit the protocols for their LDAR program to WYDEQ for approval. Thus, if the protocol includes a request to use an alternative instrument based monitoring method or technique besides Method 21 or an OGI/IR Camera, then WYDEQ could approve that if it deemed it to be acceptable.

As of the date of this document, no company has submitted an LDAR protocol to WYDEQ requesting the use of an alternative instrument based monitoring method or technique *(inquiry only submitted for TDLAS in June 2017; check w/Jeff Wendt at a later date to see if an official application/protocol request has been submitted).*

Per email 4/5/17 with Jeff Wendt, P.E., District Engineer, Wyoming Department of Environmental Quality, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

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

3.3 International Methane Emission Regulations

Outside of the United States, a few other countries have adopted or are in the process of adopting regulations to reduce methane emissions from the oil and gas sector. The basis for these regulations is often to help meet commitments for greenhouse gas (GHG) reductions under international climate agreements. A summary of select countries with methane regulations or methane reduction requirements for the oil and gas industry is summarized below.

3.3.1 Canada

In Canada, federal regulations were proposed on May 27, 2017 to regulate hydrocarbon emissions from the upstream oil and gas sector. The requirements cover five main hydrocarbon (methane and VOC) emission sources, including leaks from equipment. The proposed regulations require LDAR three times per year at production sites, gas processing facilities, and transmission facilities. Operators must inspect equipment components three times per year using portable monitoring instruments or optical gas imaging instruments or an approved alternate leak detection technology. Approval for the use of the alternate technology will be granted at a facility level. Fast-tracked approvals are possible if any other jurisdiction has approved the use of the technology. Approvals are granted based on data collected by the operator over a 12 month period to show that the alternate leak detection technology is capable of detecting a leak of hydrocarbons that is detectable by an optical gas imaging instrument. The operator must also provide a description of the technology including detection limit, protocols for use, and repeatability. Final regulations are expected to be published by the end of 2017.

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3.3.1.1 Canadian Provinces

There are provincial directives in place to manage fugitive emissions, particularly in British Columbia and Alberta, where the majority of on-shore oil and gas activities are occurring. Saskatchewan, a major oil and gas producing province, has a directive in place to address venting, but does not address the management of fugitive emissions. The provincial directives are not entirely consistent and do not cover all sources of fugitive and venting emissions. Directives are generally considered non-binding and non-enforceable unless incorporated by reference in a regulation or permit. Permits issued by the provinces are site-specific authorizations for a specific activity or industry, and can vary in the type of sources covered and the stringency of requirements.

3.3.1.1.1 Voluntary measures:

The Canadian Association of Petroleum Producers (CAPP), an industry association, developed the voluntary *Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities* (BMP) in 2007 [Publication # 2007-0003, published January 2007 http://www.capp.ca/publications-and-statistics/publications/116116]. It was developed to reduce fugitive emissions of methane and volatile organic compounds at oil and gas facilities. The BMP provides guidance for developing fugitive management programs which focus on areas most likely to offer significant cost-effective control opportunities (on specific component types and service applications), without providing firm time limits on inspection frequency or repair time. This BMP is referenced in British Columbia's *Flaring and Venting Reduction Guideline* and Alberta's *Directive 60* which state that facilities must develop and implement a program which "meets or exceeds the CAPP *Best Management Practice for Fugitive Emissions Management*". The CAPP BMP lists a number of methods that could be used to detect, measure or estimate leaks, and assesses qualitatively the effectiveness and approximate cost of these methods.

3.3.1.1.2 Proposed regulations:

The Alberta Energy Regulator (AER) proposes to release draft regulations for methane emission reduction in the upstream oil and gas sector. The regulations would cover fugitive emissions, requiring leak detection and repair, as well as measurement, monitoring and reporting. The regulations will be referenced by the directive D-60. Implementation may be in 2018 or later.

http://www.jwnenergy.com/article/2017/1/new-alberta-methane-emission-reduction-regulations-come-summer

3.3.1.2 Norway

According to the Norwegian Environmental Agency, "Methane emissions are covered by Norway's GHG reduction goals. Norway plans to reduce its global greenhouse gas emissions by the equivalent of 30 % of its own 1990 emissions by 2020. By 2030, Norway plans to reduce its GHG emissions by the equivalent of 40 % compared to the 1990 emissions." (http://www.miljodirektoratet.no/en/Areas-of-activity1/Climate/Short-Lived-Climate-Pollutants/Key-regulations-and-goals-on-SLCPs-in-Norway/).

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Norway regulates methane emissions from the oil and gas sector through several acts or laws, including the Pollution Control Act, Greenhouse Gas Emission Trading Act, CO_2 Tax Act (offshore) and the Petroleum Act. *(Try to obtain details on any possible LDAR requirements – contact NEA)*

3.3.1.3 Mexico

As a result of Mexico's participation in the United Nations Framework Convention on Climate Change, the state-owned oil company of Mexico, Petroléos Mexicanos (PEMEX), has taken steps to reduce methane emissions from its operations, including implementation of the Nationally Appropriate Mitigation Actions (NAMA) with the assistance of the British Embassy Prosperity Fund. The goal of NAMA is to reduce methane emissions in natural gas processing, transport, and distribution systems through periodic leak detection and repair (LDAR) activities. NAMA outlines both qualitative and quantitative methods for detecting leaks, including bubble tests, optical gas imaging (OGI), ultrasonic leak detectors, portable organic vapor analyzers, quantitative remote sensing techniques, and engineered estimates. PEMEX may also follow internationally recognized methods for leak identification, such as EPA Method 21.

3.3.1.4 Saudi Arabia

Saudi Arabia requires semi-annual LDAR inspections at oil and gas facilities that can be reduced to annual inspections if leaks are reduced. Facility operators must keep track of all leaks found and repaired and report them on an annual basis. Note, however, that the regulations do not outline proper leak detection methods or provide repair guidelines, therefore, operators can implement different methods and repair thresholds and timeframes.

3.3.1.5 Australia – New South Wales

The state of New South Wales in Australia has regulations to limit methane emission leaks from coal seam gas (CSG) operations. The regulations require CSG operators to develop and implement an LDAR program for their operations. Leak monitoring must be conducted in accordance with U.S. EPA Method 21 and U.S. EPA's Best Practices Guide for Leak Detection and Repair. (http://www.epa.nsw.gov.au/resources/epa/2564-methane-fact-sheet.pdf)

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3.4 Summary of Fugitive Emission/LDAR Regulations

Table 1 – LDAR Regulations table by sector

LDAR Regulations Details						
Government Type (Federal, State, Local, International)	Required Monitoring Method or Technology	Monitoring Frequency	Leak Standard	Alternative Monitoring Method or Technology Allowance	Pollutant Regulated	Notes
Federal -EPA – NSPS OOOOa	OGI (preferred)/ Method 21	Quarterly (compressor stations)/ semi-annual (well pads)	500ppm (method 21)/ OG (all detectable)	Yes	Methane + VOC	New and modified only
Federal - EPA – NSPS OOOO	Method 21	Varies	Varies	Yes (AWP - OGI)	VOC	Gas Processing only
Federal - PHMSA	Varies	Varies based on location (at least every 5 years)	Varies based on location	Yes	Methane	
Federal - BLM	OGI (preferred)/ Method 21	Quarterly (compressor stations)/ semi-annual (well pads)	500ppm (method 21)/ OG (all detectable)	Yes	Methane	
Canada - Federal - Proposed regulation	Method 21 / OGI	3 times per year	500ppm (Method 21) / OGI (all detectable)	Yes	Methane + VOC	New and existing. Production processing, transmission, storage, excludes distribution.
Canada - Alberta Directive 084	Method 21 / OGI	monthly inspection for targeted components (thief hatches, pressure vacuum relief valves, gauge board	500ppm (Method 21) / OGI (all detectable)	Yes	Methane + VOC	Peace River area only. Existing. All wells and facilities associated with heavy oil and bitumen

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		assemblies, flare ignitor or pilot, compressor seals) and weekly AVO inspection for all components.				operations
California	Method 21	Quarterly	1,000 PPM	No	Methane	
Colorado	OGI/Method 21	Varies	500 - 2000ppm	Yes	Methane + VOC	
Pennsylvania	OGI	Monthly		Yes	Methane + VOC	
Ohio	OGI/Method 21	Quarterly/then Varies	500 - 10,000 PPM depending on component	Yes	Methane + VOC	
Utah	OGI/Method 21/TDLAS	Quarterly or annual depending on throughput	500ppm (method 21)/ OG (all detectable)	No	VOC	
WY	OGI/ Method 21	non-attainment (more stringent) - quarterly		Yes	VOC	
NY - Under Development	TBD	TBD	TBD	TBD (Yes)	TBD (proposed Methane + VOC)	
Alberta (Canadian province) - Pending	TBD	TBD	TBD	TBD	TBD (proposed Methane + VOC)	
California Air Districts	Method 21	Varies	Varies (ES will provide ranges)	No	VOC	

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If states not listed, have no state specific requirements and are only following EPA requirements						

3.5 Current Limitation and Needs (Barriers and Opportunities)

3.5.1 Barriers to implementation of alternate leak detection technologies/methods:

As discussed extensively in this chapter, there are multiple jurisdictional layers of rules for leak detection and repair requirements at oil and gas facilities throughout the natural gas supply chain. For the most part, upstream leak detection regulations are mostly based on detecting and reducing VOCs and methane whereas downstream rules are more safety oriented. Federal rules set a baseline minimum and states and local regions can be more stringent for air quality and climate change regulations. A similar hierarchy generally exists for state and local environmental regulations.

The system of regulations limits emissions across the supply chain but there are gaps and limitations in the layered, bifurcated system. The transmission and distribution sector does not consider leak repairs for methane or other air emissions but purely for safety except in limited cases such as new required practices in California. In practice this means that leaks in non-hazardous areas need to be monitored but could continue for decades even if they emit significant amounts of methane. Additionally, storage facilities are not as strictly covered for methane and VOC emissions as production and processing facilities. The recent Aliso Canyon event raised concerns about the safety and environmental considerations for these facilities.

Production and processing facilities are subject to leak detection and repair requirements both nationally and, in some cases, at the state and local levels. In some cases, these requirements are based on VOC emissions and in some jurisdictions, these measures are part of their SIP requirements to meet national ambient air quality standards for ozone. As such, any changes in approach must be able to be proven to meet or exceed the level of reductions already achieved. Sources within these sectors that are often exempt from LDAR are non-active wells (idle, abandoned, orphan), low producing wells, and very heavy oil wells.

Generally LDAR is based on two main technologies. Until recently, U.S. EPA's Method 21 was the only regulatory option for compliance with LDAR regulations. Optical Gas Imaging has been incorporated into national and some state requirements. In addition, some states have alternative compliance options but criteria for showing equivalency can be either complex or uncertain. The two approaches offer different advantages and disadvantages, with Method 21 based on easily enforceable concentration standards but can be labor intensive. OGI offers a quicker alternative that could mean more frequent inspections but with a higher detection limit, lack of a standardized Method such as Method 21, and more intensive training. Neither

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technology is currently required in a continuous mode. The more frequent and more accurate the technology, the more likely super emitters are to be detected quickly.

Regulators need to achieve several goals when determining the method and standards for implementation. The main objective for air quality related regulations is to reduce emissions to the maximum extent feasible while considering impacts such as cost. Costs are part of the consideration for many regulators and are considered when developing rules for required methods. It is also a consideration for alternative methods in regards to the availability of the technology to inspectors.

In addition, regulators need to ensure that a regulation is enforceable and reductions can be verified through inspections and reporting. For this reason, traditionally, some VOC and methane regulations have been based on concentration standards as emission rates are not easily quantifiable even currently. Some recent regulations rely on visualization versus concentration thresholds. In either case, regulatory inspectors need to be able to go out and inspect and determine if an entity has any violations. Therefore, any alternative method needs to be able to be understood and implemented by regulators and the equipment needs to be available for inspectors to own or at least have unfettered access. Training for inspectors needs to be available.

Methods of evaluation are also important. New technologies can have many variables which impact effectiveness. For example, distance from source, weather conditions, and other variables need to be considered. Regulators need to ensure that the requirements are clear so that regulated entities know what will lead to a violation.

Related to both enforceability and methods, transparency is important. Technologies and methods that are clear to all sides are preferred for clarity for the regulated entity, inspectors, regulators, and concerned citizens. Visualization can offer a helpful tool to concerned citizens if it can be easily described and translated to the public.

For many areas with air quality issues, regulators need to meet both climate and air quality objectives so methods of compliance need to address both greenhouse gases and VOC. This means that alternative methods must be able to measure both sets of gases or show that both are addressed through total hydrocarbons or other metrics.

As regulators develop and amend regulations, they need significant levels of information. It is more difficult to include a technology if there is a lack of detailed information on the technology or a method for evaluation; insufficient data or case studies to evaluate the performance or compliance status; lack of resources to verify the performance, etc. The developer may only provide limited information for competitiveness reasons, which further limits the accessibility. Regulators need this information and many times are able to keep information confidential. Regulators could request additional information or data to support their decisions, which could demand further research, or new data collection for demonstration that takes time and efforts. There is no guarantee of approval but close coordination between technology providers and regulators leads to a smoother process.

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The performance of the technology and the compliance status of a new technology could be based on work practice, specific test method or alternative monitoring approaches, which could be different from the traditional methods. It is challenging to establish the equivalent compliance criteria to the traditional method. The smooth review or approval of a new method also depends on the process whether it is established or streamlined. The criteria across jurisdictions could be different and therefore lead to inconsistency of product specifications and uses, which could discourage the development or optimization of the product.

Developers, producers and operators could also encounter challenges during the approval of the technology. Due to lack of established procedures or protocols or different compliance criteria, developers may need to collect more data, or change the functions or specifications to demonstrate performance and compliance. Depending on the cost and efforts required for demonstration, the cost and effort is challenging for the developers. Further, regulators may require using the technology in combination with existing approved ones. The cost for using the product can be prohibitive to operators and the product itself is more expensive than traditional products. Overall it could be a risk for all parties to invest in the product due to the challenging approval process, potential higher cost to develop and operate the product. However, many regulators are open to new and evolving technologies as long as they can meet requirements, have an established methodology, can show equivalency, and offer flexible, lower costs alternatives that are enforceable and understandable to regulatory staff. Coordination between regulators and technology developers can help make this process more smooth and understandable to all parties.

Proving technologies in individual sectors and participating in rulemakings and research can also help move technologies forward. For example, storage facilities and dry gas fields are primarily methane and could be a good space for proving methane specific technologies.

3.5.2 Areas of Opportunity

3.5.2.1 Areas of Opportunity – Legal

The United States EPA and state regulators may issue Consent Decrees / Orders that require VOC emission reductions. Many of the VOC emission reductions have a co-benefit of reducing methane emissions. Some Consent Decrees require the use of leak detection technology that is currently not specifically required by regulations. This gives regulators an opportunity to implement proven technology ahead of regulations. The USEPA Emission Measurement Group which is responsible for updating air emission test methods. Where appropriate EPA updates test methods that are technology neutral. The test method specifies the technology performance criteria. Any technology that can meet the performance criteria is acceptable.

The following are examples of technology specified in enforcement actions:

- The 2016 North Dakota and USEPA Consent Decree for Slawson Exploration Company. The federal regulation requires oil and natural gas wells to route all natural gas emissions from production operations and storage operations to a control device with periodic audible, olfactory and visual inspections. EPA inspectors used an IR camera for visual inspections of

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the closed vent. The Consent Decree requires the use of two (2) technologies to prevent natural gas leaks.

- Semi-annual IR camera inspections of all Tank System openings (i.e., PRDs/thief hatches), emission control devices (i.e., VOCs not being emitted without flame presence indicating combustion), and open-ended lines during Normal Operations, including while Produced Oil is being sent to the Tank System from all associated Production Operations, to confirm the Vapor Control System is adequately designed and sized and not emitting VOC. The decree also requires Slawson to use 3rd party auditors to conduct IR Camera Inspections.
    - Slawson shall install, calibrate, operate, and maintain one analog pressure monitor per battery of Storage Tanks with head spaces manifolded together. If the recorded maximum pressure reading is above the Trigger Point for a Tank System, Slawson shall test the pressure monitor and the operating parameters of the associated Tank System and while on site shall either conduct an IR Camera Inspection or an AVO inspection of the Tank System. In the event a Tank System has three recorded maximum pressure readings above the Trigger Point in a calendar quarter (e.g., January through March), Slawson shall conduct a VCS Root Cause Analysis. Each electronic pressure monitor shall continuously measure and record pressure data (i.e., one measurement every 15 seconds), which shall be stored onsite in a format that is capable of being downloaded for review. Each electronic pressure monitor shall be connected to a visual alarm at the Well Pad that lights up (and remains lit until manually reset) when a measurement has exceeded the Trigger Point.

- 2015 Colorado and USEPA Consent Decree for Noble Energy, Inc. The Consent Decree requires the use of two (2) technologies to prevent natural gas leaks.
    - Conduct an IR Camera Inspection of each Tank System closed vent during Normal Operations and during and immediately after a dump event to confirm the Vapor Control System is adequately designed and sized and not emitting VOCs. The frequency of the IR camera inspections depends on the Tank System uncontrolled VOC emissions. The most frequent IR camera inspection is on a monthly basis. The decree also requires Noble to use 3rd party auditors to conduct IR Camera Inspections.
    - Noble shall install, calibrate, operate, and maintain pressure monitors that continuously monitor each Tank System closed vent. Following the performance optimization period, if there are two or more measurements within a 48-hour period that exceed the "trigger point" for a Tank System, Noble shall conduct a site investigation. The investigation shall include a site visit to test the pressure monitor and the operating parameters of the associated Tank System. During the site visit, Noble shall either conduct an IR Camera Inspection or an Audio, Visual, Olfactory ("AVO") inspection of the Tank System. In the event a Tank System requires three site investigations in a consecutive 30 Calendar Day period, Noble shall conduct a VCS Root Cause Analysis.

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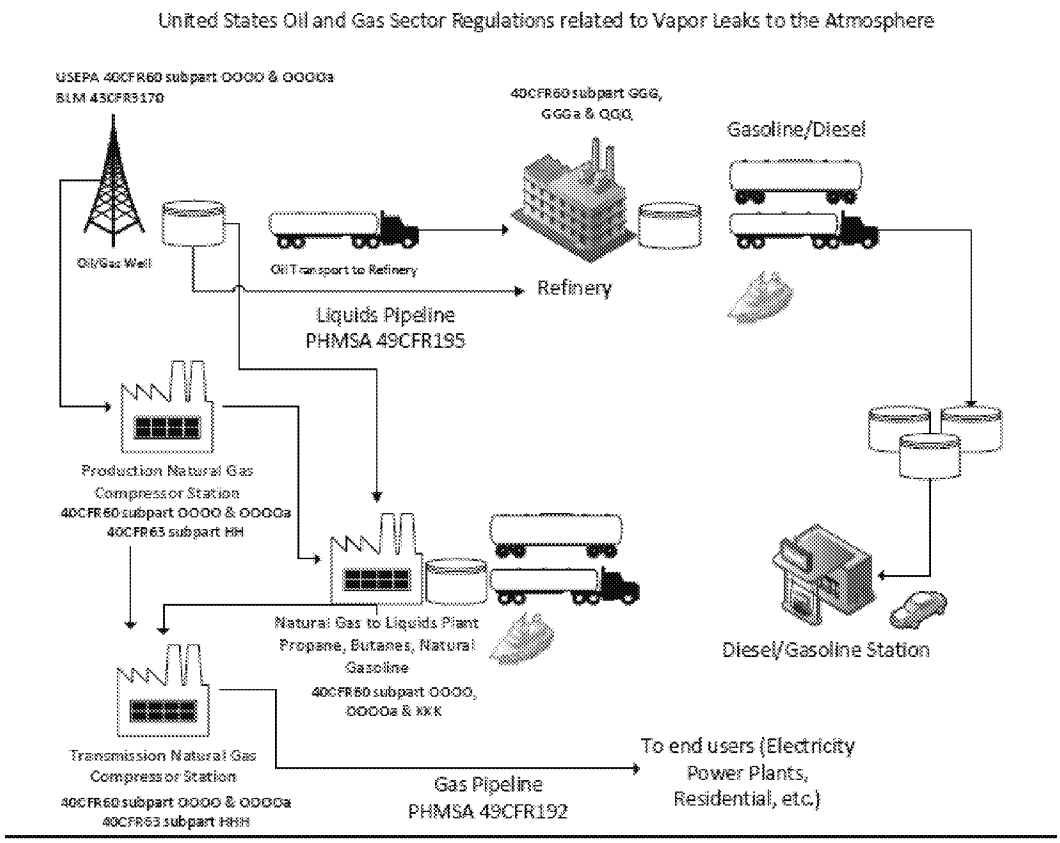
3.5.2.2 Other Areas of Opportunity

- In different industry segments (with different typical gas compositions) it may be possible to allow leak detection technologies with limited capabilities. For example, when inspecting equipment carrying predominantly dry gas, it may not be necessary for an alternate technology to be capable of detecting VOC. Programs should remain flexible in approvals depending on the application of the alternate technologies.

- Now is a good time for technology developer to interact with regulators, because the trend is for increased state level action on methane and VOCs. Developers need to take on a more active role in the assessment of the equivalence of their new technologies.

- Participate in EPA or state-funded research or development program to develop a new technology/method so that all levels have same understanding about the product, meeting the regulatory requirements. Accordingly, the approval process could them be conducted more efficiently.



Regulations graphic by James Jarrett (EPA document stated the oil and gas sector starts at the well site and ends at the refinery).

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4 TECHNOLOGY

4.1 Introduction

Many technologies for methane detection exist in the market or are under development. Methane detection technologies have been rapidly evolving in recent years, and this section will describe some of that evolution in a brief review of the history of methane detection. This section will describe some of the recent developments, as well as a template against which future developments can be evaluated. Performance criteria of methane detectors that may be relevant for different applications are described that can then be used to characterize the accepted and emerging methane detection technologies according to their capabilities, limitations, costs, and uncertainties.

4.1.1 History of Methane Detection

Methane leak detection has been performed since natural gas was first captured and transported by pipelines to customers. Originally gas was seen only as a byproduct of producing oil in the 19th century, and gas was burned off at the oil field production. As markets developed for gas, the gas was instead captured and moved to customers, and keeping the gas in the production system became important since gas was then a saleable product. The original leak detection methods applied were simple "audio, visual, and olfactory" (AVO) techniques, wherein an operator of natural gas systems would seek to detect a leak by human observation whenever near their equipment. In certain conditions, and for certain leak sizes, a person can detect the sound of a leak, or the smell of emitted gas, or other visual signals, such as darker deposits left on the equipment near a leak source where heavier condensing components in the gas stream drop out. As pipeline systems grew, AVO techniques were also applied to leak detection for natural gas transmission pipeline routes, where the operator would walk, drive, or fly over the buried pipeline route looking for signs such as dead vegetation or openings that may indicate a leak area. AVO techniques are still used today, though emission detection devices now offer far superior ability to detect leaks both for above ground and buried pipeline equipment.

As the natural gas systems and pipeline networks grew, so did best practices among natural gas pipeline operators. Often these were then codified by regulatory bodies, so that routine leak detection became a requirement for local distribution systems and transmission pipelines.

Also, after passing of the Clean Air Act in 1970, emissions from other industries that handle more toxic chemicals became a national focus, leading to the development of fugitive detection techniques, such as the US EPA's Method 21, which defined a technique that identified all potential leaking components and used a flame ionization detector (FID) to find hydrocarbons in air around any leaking industry equipment. Though Method 21 was not intended originally for natural gas systems, it did become the standard for leak detection on above ground equipment in other industries, and defined a rigorous fugitive emission measurement technique.

Local distribution companies (LDC's) that bring natural gas to consumer's businesses and households have always had a high need for leak detection simply because of the proximity to the public, and the larger consequences of a leak. They have long used a routine leak detection walk with a sniffer device like an FID to seek to detect any leaks in the buried distribution

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pipeline system. Today, a much wider variety of detection options are already deployed by LDCs.

Similarly, transmission and storage companies have deployed a variety of detection techniques that have been added to their routine pipeline right of way surveys using AVO. Some of these include cameras that can detect increased methane concentrations from aircraft flyovers. In above ground facilities, such as compressor stations, other leak detection techniques have been applied in recent years, such as the Optical Gas Imaging (OGI) cameras that were required to be used under the 2008 Greenhouse Gas Reporting Program. These are described later.

At the farthest upstream, at natural gas producing wells, leak detection devices have been traditionally used only in research projects until the past decade. As these facilities were usually the farthest from the public, they were not as heavily regulated as downstream operations, such as distribution. So upstream was probably the last segment of the natural gas supply chain to begin to apply leak detection devices. In the past decade, some upstream companies have implemented voluntary leak detection programs using handheld OGI cameras and handheld Tunable Diode Laser Absorption Spectroscopy (TDLAS) devices. In a few states, these have become requirements.

Research did bring new detection developments to the whole supply chain. Staring in the early 1990's, the importance of greenhouse gas impacts of leaks was given additional political consideration, and there became a need to determine the amount of gas leaked by the natural gas supply chain. This lead to development of new national estimates (called emission inventories) of the system, and new field measurements of emissions. In fact, new measurement techniques were developed, such as the HiFlow sampler, because of these efforts. The HiFlow sampler was designed to quantify, rather than just detect, a leak rate. The Hiflow sampler became a commercial product in the 1990s, and remains one of the only devices to directly quantify the rate of a found leak.

Commercial enterprises have also produced new detection techniques, such as the Optical Gas Imaging (OGI) cameras commercially offered by FLIR and by Opgal beginning in the early 2000's. These handheld cameras make detection possible by display in a screen, allowing visualization of a gas plume that is otherwise invisible to the naked eye. Other commercial products from a variety of sources use multispectral and hyperspectral cameras for plume detection, such as the Rebellion Gas Cloud Imaging camera. These devices remain expensive and so are carefully and perhaps sparingly deployed. For ambient air samples, many developments have been made in the past ten years that have increased the accuracy of the determination of the fraction of methane in air. An example is the Picarro Cavity Ring Down system, which has been deployed in many vehicle based downwind or ambient air studies, including use in distribution system screening vehicles.

In more recent years, the Obama Administration issued its Climate Change Action Plan and Methane Action Plan and thus added political goals for methane detection and emission reduction along the entire natural gas supply chain. The industry has also had other motivations as well, to show that a small enough fraction of gas is leaked that natural gas would remain the preferred fuel for expansion when considering global warming and greenhouse gas impacts. Research projects were created to develop new detection techniques, such as the ongoing

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Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) by the US Department of Energy's Advanced Research Projects Agency – Energy (DOE ARPA-E), and the Methane Detectors Challenge by the Environmental Defense Fund. Both of these efforts had specific goals to produce new detection techniques that were much less expensive.

In addition to sponsored research efforts, development of independent commercial technologies continues by individual companies. These vary from open path approaches such as Boreal Laser to systems that aim to add quantification to OGI camera image captures, such as Providence Photonics QOGI systems. In future years, these research efforts, and the development efforts of independent commercial enterprises are expected to produce new detection devices and offerings.

4.1.2 Classification Scheme

This review has added a classification approach for evaluating different technologies, so that currently existing commercially offered technologies can be compared to technologies that are currently being developed, or those that may emerge in the future. The classification approach used in this document compares the technologies by result type, data type, time period covered in a measurement, size, working distance, deployment method, relative cost, measurement limitations, as well as other features such as safety, interferences, durability, and other ancillary benefits. Each of these comparison categories is discussed briefly below.

Primary Data Type. Different systems may present data in various formats. Quantitative systems will produce a value, such as ppm or a leak rate g/hr. Qualitative systems may provide data in different formats, such as a video image, or a processed image from an Optical Gas Imaging camera.

Result Type. Results from emission sensing and measurement devices are generally in one of three categories. 1) "Qualitative" systems provide a leak or no leak detection, but do not provide emission rate quantification; 2) "Quantitative (concentration)" systems generally provide a concentration of the emitted species in air, such as a parts-per-million (ppm) reading, but do not inherently provide emission rate quantification; and 3) "Quantitative (emission rate)" systems provide a measurement of the actual emission or leak rate, such as g/hr. If the desired end result is a quantification of emission rate, it must be understood that a "quantitative (concentration)" system does not provide that result.

Measurement temporal resolution. To be written.

Size. This basically describes the device size, which has some implications for how it can be deployed. Some of the size categories are: 1) "small" (such as small distributed printed card detectors); 2) "handheld" which would apply to equipment portable by one person, such as the HiFlow backpack, some of the Optical Gas Imaging cameras, or the TDLAS device by Heath called the RMLD, 3) large, which would include devices that have to be "vehicle based" such as some of the larger equipment driven in ground vehicles or airplanes, like as the Picarro cavity ring down system, or the Rebellion Gas Cloud Imaging system.

Deployment Method. This describes the normal means of deployment for the system. Some systems may be deployable in multiple methods. These can be: 1) "walking" for handheld

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devices; 2) "vehicle path" for airplane or vehicle based systems; 3) or "fixed location" for some systems. Some systems may be deployed in downwind ambient air measurements only, while some may be applied directly at the emission location.

Working Distance. Working distance refers to the minimum and maximum distance that a technique can be used. This will vary by the detection limit desired for the regulatory purpose. For example, the detection abilities of OGI cameras are known to diminish with distance; the closer they are to the leak, the smaller the leak they can see. OGI cameras are normally deployed as handheld screening devices by an operator walking around a facility, and therefore used in the 2 ft to 50 ft range from any source. In this range, they have a certain threshold for minimum leak size that can be detected. However, they can be deployed from much farther away, such as in an aerial flyover of several hundred feet, if the user is willing to accept a poorer (higher) mimimum threshold of leak detection. Some techniques, such as the flame ionization detector used for EPA's method 21, require extremely close proximilty (close to 1 cm), while others, such as Rebellions GCI camera, require a much longer setback farther than the OGI camera. Finally, some methods, such as the HiFlow device requires direct contact and partial enclosure; the distance is zero.

Environmental Limitations. These will list in text format, any known limitations for the method, such as atmospheric delta temperature limitations for the OGI camera that mean that not all days nor all times of day are suitable for measurement or stable winds to transport plumes to the measurement point.

Calibration Procedures.

Maturity. Maturity will be listed as research, development/evaluated, single source, or multiple source. Research is for technology that has undergone testing in the laboratory environment. Development/evaluated is for technology that has undergone field testing and has been considered as a viable technology for regulatory or industrial use. Single source is a technology that is commercial available from vendor but is limited to a single vendor due to IP or market considerations. Multiple source is a technology that is commercial available from multiple vendors.

Durability, Service Factors, and Calibration and Maintenance Requirements. This miscellaneous category will describe issues that may differentiate a system, such as frequent calibration requirements vs no calibration requirements, or known high or low service factors for particular systems. These will be spelled out.

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4.2 Technologies

4.2.1 Data Type and Characteristics

Table 4-1. Available methane detection technologies and application domains

Tech	Application 1	Application 2	Application 3		
1					
2					

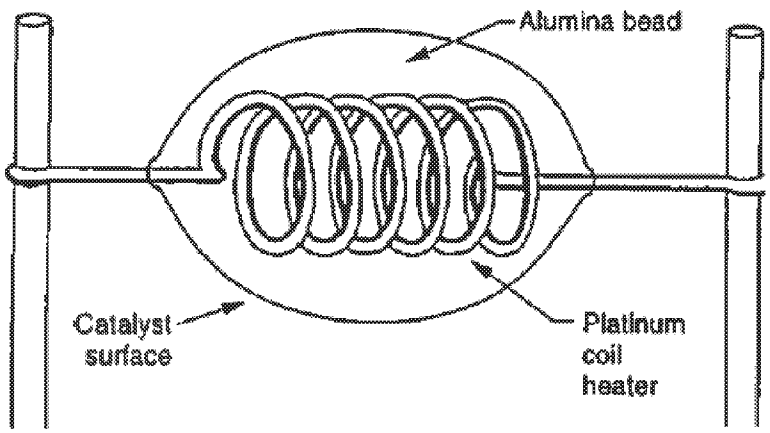
4.2.2 Technology Descriptions

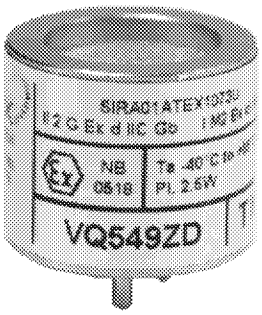
4.2.2.1 Pellistor (Catalytic Bead)

Description:

Pellistor sensors are based on the reaction between VOC or Hydrocarbon gas and a catalyst material. The catalyst promotes oxidation of the gas. Often a reference element is used to compensate for environmental conditions such as ambient temperature and humidity. The Pellstor element is heated to the point that the target gas burns, causing a change is the element resistance. The amount of resistance change is proportional to the gas concentration.

Drawing of an element





Characteristics:

1. Primary Data Type: Analog voltage level

2. Result Type: Quantitative gas concentration
3. Detection Range: Low %gas by volume. Typical instrumentation range from 500 ppm to 5% v/v methane. Accuracy is typically in the ±10% of reading.
4. Specificity/Interference: nonspecific; cross sensitivity to VOC's
5. Other Benefits: Low cost sensors are widely used throughout industry
6. Measurement intermittency: Continuous
7. Measurement temporal resolution: Hz
8. Size: From handheld
9. Deployment Method: Fixed
10. Working Distance: Point measerment
11. Environmental Limitations: Humidity, temperature, contaminates
12. Calibration Procedure: Calibration gas. Typical calibration period is between weeks to months depending on exposure.
13. Maturity/TRL: Mature
14. Durability, Service Factors, and Calibration and Maintenance Requirements: Sensors have a short life depending on level of contaminates it is exposed to. Sensors may be damaged by shock or vibration. Loss of sensitivity when exposed to organic materials. Exposure to high gas concentrations may reduce sensor life.

Use:

Mode of use: Catalytic Bead Pelistor is suitable for leak detection of VOC and hydrocarbons. It is non-selective to the gas species. Typically, the technology is used as a portable gas detection instrument. This sensor technology is most often used in Combustible Gas Indicators and personal protection devices for the measurement of explosive levels of gas.

Performance:

Typical instrumentation range from 50 ppm to 5% v/v methane.

Figure x: Portable combustible gas indicator. Source GMI.

Response time is typically in the 2 to 4 seconds depending on type of gas and design.

Calibration:

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Limits of Use:

4.2.2.2 Metal Oxide Semi-conductor (MOS)

Description:

Metal Oxide Semi-conductor (MOS) sensors are semiconductor circuits specifically doped with oxide materials that will react to the intended target gas. Tin Dioxide is commonly used for methane and VOC detection. When gas particles react with the oxide material, a change in resistance of the sensor occurs. The amount of resistance change is proportional to the gas concentration. Often the sensor includes a heating element to raise the sensor temperature to minimize the effect of water vapor and to maximize the reaction to the target gas.

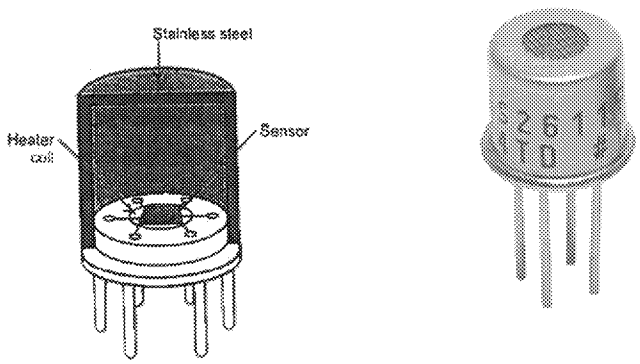

Figure x: MOS sensor element. Source: Figaro.

Characteristics

1. Primary Data Type: Analog voltage level
2. Result Type: Quantitative gas concentration
3. Detection Range: Typical sensors have sensitivities in the range of 50 ppm depending on the specific sensor design.
4. Specificity/Interference: nonspecific; cross sensitivity to VOC's
5. Other Benefits: Low cost sensors are widely used throughout industry
6. Measurement intermittency: Continuous
7. Measurement temporal resolution: Hz
8. Size: Handheld
9. Deployment Method: Fixed
10. Working Distance: Point measurement
11. Environmental Limitations: Humidity, temperature, contaminates
12. Calibration Procedure: Calibration gas. Frequent calibration is required. Upon power, sensor must zero on the ambient air condition.

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13. Maturity/TRL: Mature
14. Durability, Service Factors, and Calibration and Maintenance Requirements: MOS sensors will react to a wide range of different gases. Often false readings are experienced by rapid change in the ambient air (e.g. moisture and temperature). Exposure to high gas concentrations may de-sensitize the sensor lasting for a prolonged period or may have irreversible change to its zero-gas reading or sensitivity. Exposure to basic or acidic compounds, silicones, Sulphur and halogenated compounds may have significant irreversible effect on sensitivity. High Oxygen concentrations may have significant irreversible effect on sensitivity.

Mode of use: MOS is suitable for leak detection of VOC and hydrocarbons. It is non-selective to the gas species, and is highly responsive to other gases. Typically, the technology is used as a portable gas detection instrument. This sensor technology is most often used for applications which don't require very high sensitivity and don't have high gas concentrations. Often the sensor is used to "sniff" around fittings.

<<insert picture of instrument>>

Performance:

Typical sensors have sensitivities in the range of 50 ppm depending on the specific sensor design. Response time is very fast (typically in the 1 to 5 seconds) depending on the instrument design.

Calibration:

Figure x: Portable gas indicator with MOS sensor tip. Source: GMI

Upon power up, the sensor must zero on the ambient air condition.

Limits of Use:

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MOS sensors will react to a wide range of different gases. gas reading or sensitivity.

4.2.2.3 Flame Ionization Detector (FID)

Description:

Flame Ionization is a sensor technology which measures the relative gas concentration through a method of passing the sample air through a combustion chamber were the sample gas is burned at high temperature in a clear hydrogen flame. VOC and hydrocarbons molecules are charged through the burning process to become ions. The positive charge of the ions then are collected onto a electrode. The amount of positive charge on the electrode is then proportional to the gas concentration.

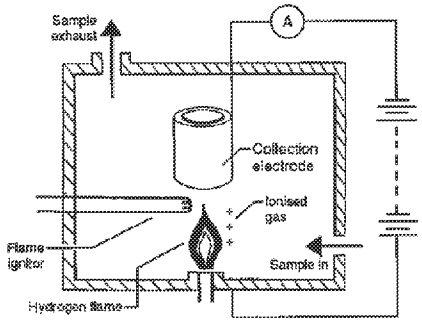

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Figure x: FID cell. Source: Heath Consultants

Characteristics:

1. Primary Data Type: Analog voltage level
2. Result Type: Quantitative gas concentration
3. Detection Range: Typical sensors < 5ppm depending on the specific sensor design.
4. Specificity/Interference: nonspecific; cross sensitivity to VOC's
5. Other Benefits: Low cost sensors are widely used throughout industry
6. Measurement intermittency: Continuous
7. Measurement temporal resolution: Hz
8. Size: Handheld
9. Deployment Method: Fixed
10. Working Distance: Point measurement
11. Environmental Limitations: Humidity, temperature, contaminates
12. Calibration Procedure: Calibration gas. Frequent calibration is required with a field calibration kit. Upon power, sensor must zero on the ambient air condition.
13. Maturity/TRL: Mature
14. Durability, Service Factors, and Calibration and Maintenance Requirements: FID is not suitable for detection of carbon monoxide and inorganic gases. High gas concentration will cause a flame out. Halogenated hydrocarbons reduce the sensor response and will affect the measurement of the total hydrocarbon concentration.

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Mode of use: FID is suitable for leak detection of VOC and hydrocarbons. It is non-selective to the gas species. Typically, the technology is used as a portable gas detection instrument. See Figure: <<xx>>. Instruments require the use of hydrogen fuel carried in small DOT compliant cylinders. Typically, the hydrogen fuel cylinders are restricted from being transported on airplanes and tunnels.

<<insert picture of TVA and DP4>>

Performance:

Typical instruments have sensitivity of about 1 ppm v/v with a response time of under 2 seconds depending on the instrument design.

Calibration:

Regular calibration using is required, usually completed with a field calibration kit.

Limits of Use:

FID is not suitable for detection of carbon monoxide and inorganic gases.

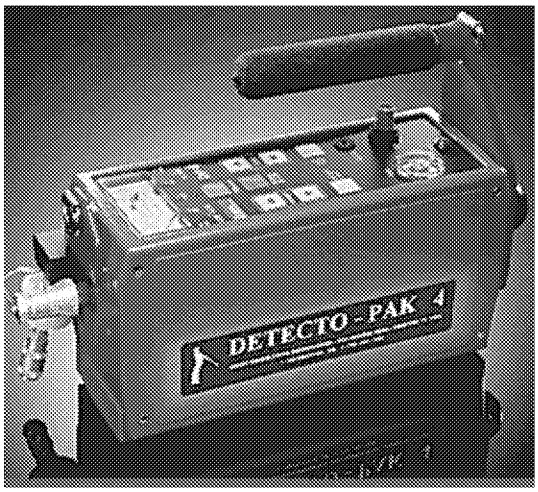

Figure x: FID gas leak survey instrument. Source: Heath Consultants

4.2.2.4 Gas Chromatography (GC).

Description:

Gas Chromatography (CG) is a system used to separate different species of gases which are then detected via other detection technologies (e.g. with FID). A typical system consists of a gas injection port, carrier gas port, separator column, detection sensor and a time chart. The separator column often is heated.

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As gas passes through the separator column, the gas components will separate from each other based on their molecular weight. As the gas exits the separator and passes through the detector, a signal vs. time trace is created. The timing of the various peaks will indicate the type of gas. The gas concentration required to make measurements vary significantly based on the instrument design. Highly sensitive systems are typically found in laboratory instruments. Portable instruments typically require higher gas concentration. Response rate is slow and varies based on the design of the separator.

Use:

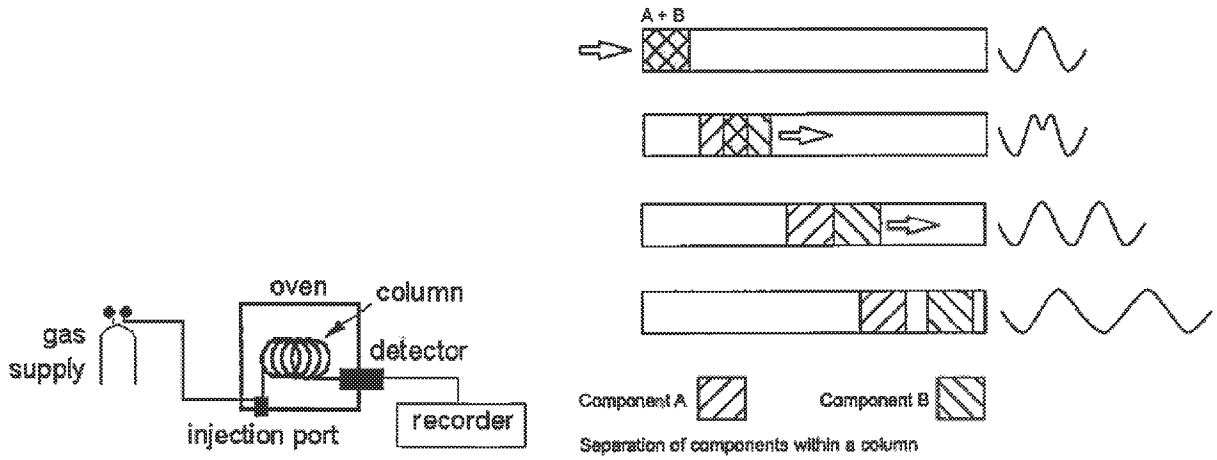

Figure x: Example gas transport and column separator. Gases of different weight transport through the column at different speeds.

Characteristics:

1. Primary Data Type: Analog voltage level over time
2. Result Type: Quantitative gas concentration or Qualitative response chart dependent on design
3. Detection Range: varies significantly between laboratory and field design
4. Specificity/Interference: not applicable
5. Other Benefits: Field instruments quickly help to determine source of gas leak
6. Measurement intermittency: Discrete sample
7. Measurement temporal resolution: 100Hz or longer
8. Size: From handheld to laboratory fixed installs
9. Deployment Method: Portable and Fixed
10. Working Distance: Point measurement
11. Environmental Limitations: Minimum gas concentration required for measurement
12. Calibration Procedure: Calibration gas. Typically, a calibration check and purge is required prior to use. Calibration frequency varies based on the instrument design.
13. Maturity/TRL: Mature
14. Durability, Service Factors, and Calibration and Maintenance Requirements: Clean dry carrier gas is typically required.

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Mode of use: Both portable and fixed systems are commercially available. Portable instruments are often used to identify the possible source of the gas. For example, natural gas will contain a percentage of ethane. So to determine if a underground gas leak is from a natural gas pipeline or from a biological source, a portable GC is used to determine if ethane is present.

Performance:

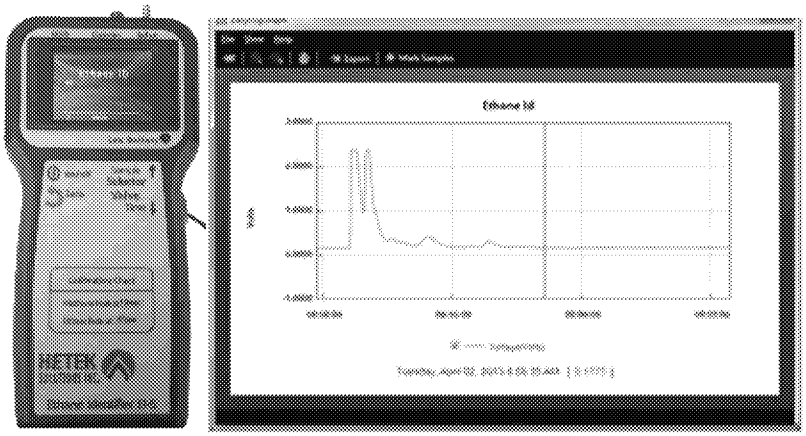

Figure x: Portable ethane identifier for discriminating natural gas containing ethane. Source: Hetek

Calibration:

Limits of Use:

Clean dry carrier gas is typically required.

4.2.2.5 Mass Spectrometry

Description:

Mass spectrometry (MS) identifies and quantifies molecules in simple and complex mixtures and helps to elucidate ion-molecule interactions. A solid, liquid, or gas sample is ionized, i.e., by bombarding with electrons, the ions are accelerated in electric or magnetic field, separated in space or time based on their mass to charge (m/z) ratio and detected. The m/z ratio is plotted vs. its relative abundance producing mass spectrum. Often mass spectrometry is used in tandem with gas or liquid chromatography for identification and quantification of mixtures.

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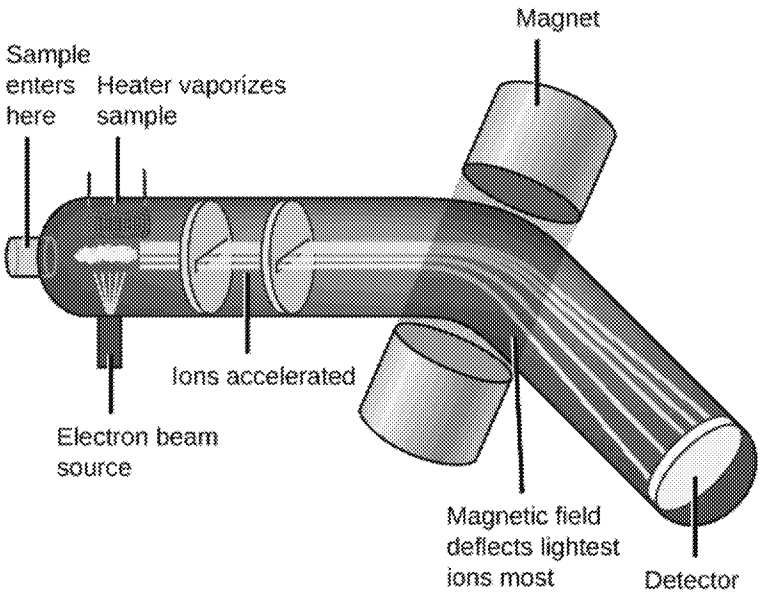

Figure 4.1: Schematic of mass spectrometer operation (*Image* from Openstax, *CC BY 4.0*.)

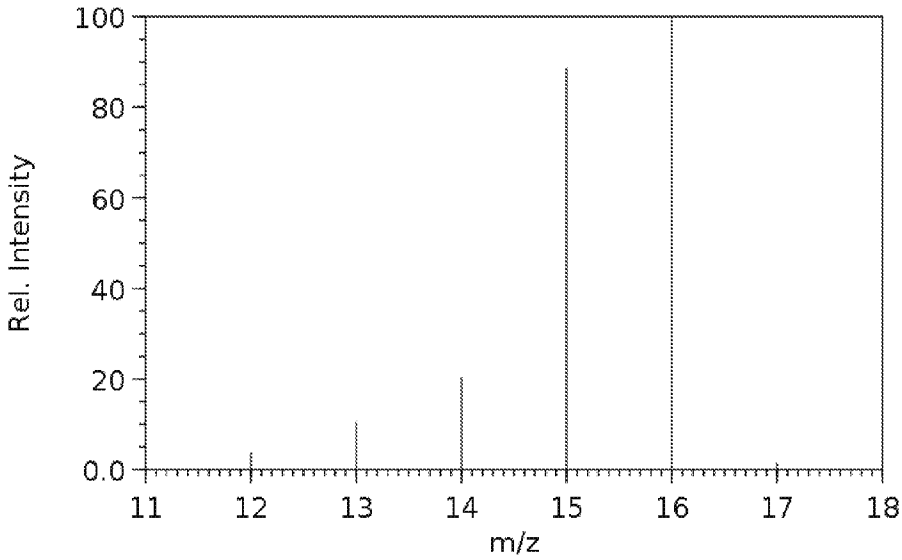

Figure *4.2*: Mass spectrum of methane (http://webbook.nist.gov/chemistry)

Recently a coded aperture miniature mass spectrometer environmental sensor (CAMMS-ES) is being developed for methane monitoring system. The instrument will be capable of continuous sampling and have increased specificity and sensitivity detection of methane and other volatile organic compounds (VOCs).

Use:

The applications of mass spectrometry range from forensic analysis, isotope dating and tracking, trace gas analysis, clinical research, proteomics, lipidomics, metabolomics to monitoring environmental pollutants and determining methane emissions.

Performance:

The response time and sensitivities are very dependent on the type of the instrument and its design. For example, inductively coupled plasma mass spectrometry (ICP-MS) can identify and characterize organic and inorganic samples down to sub-ppt levels. The response time can be as short as sub-seconds.

Calibration:

Mass spectrometry uses calibration compounds, which provide ions of known m/z ration, to adjust the calibration scale and relative intensities of mass spec peaks from low to high mass. The calibration compound is dependent on the instrument and the ionization mode (electron ionization, chemical ionization, electrospray, matrix assisted laser desorption/ionization, etc.)

Limits of Use:

There are several limitations of MS, the technique cannot distinguish geometric or optical isomers of a compound as well as ortho(o-), meta(m-), and para(p-) substituents of aromatic compounds. In some cases, the ionization process produces too much fragmentation which makes difficult identification of similar fragmented ions in hydrocarbons. Tandem techniques have been developed to help in such cases.

4.2.2.6 Printed Nanotubes Sensors

Description:

A printed nanotube sensor is an extremely low cost production procedure for the small molecule gas sensors consist primarily of functionalized and/or doped carbon . The nanotubes (CNTs) that can provide detection of a range of atmospheric species, including methane. molecules are printed on a substrate in an interdigitated form to make the sensor electrode. The nanotubes passively transported to the CNTs uptake the compounds in the air, which changes the resistance of the electrode. The uptake and back diffusion rate and change the electrical resistance response of the CNT, which can be detected and converted is dependent on compound and nanotube structure and makeup. In order to a methane concentration. Functionalizing the CNTs with a wide variety of substituents allows for detection of a variety of species. Due properly speciate and measure compounds, a matrix of different nanotube sensors is needed as each nanotube sensor responses to the low cost of the raw materials and small amounts required when combined with scalable manufacturing approaches, sensor costs can be quite low multiple compounds and interferents and are not selective. Research is on-going to determine the limits of this technology and determine chemical and engineering solutions, including the fabrication of whether a matrix of sensors with various calibrations can be used to spectate and quantify a wide variety of compounds.

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1. Primary Data Type: Quantitative (Qualitative point concentration)
2. Result Type. Quantitative, both concentration (ppm) and emission rate (g/hr) possible through modeling (secondary data).
3. Detection Range: (working distance): Variable, generally used near or on source
4. Measurement Time: <1 ppm Hz, Response time: dependent on design, can be 1 to 100+ppm minutes
5. Calibration Procedure:
6. Maturity/TRL: Research/Feasibility Stage
7. Environmental limitations: Electronics are subject to environmental damage
8. Specificity/Interference: Design-specific; Interference is difficult to mitigate without a robust variety of sensors, calibrations for each sensor and compound, and advanced computational algorithms.

4.2.2.7 Dual Frequency Comb Spectroscopy

Description:

Dual frequency-comb spectroscopy (DCS) for detection of suite of chemicals with high spatial and temporal resolution.

Current DCS technologies are based on probing molecules in the mid infrared region of the spectrum which is the fingerprint region of most molecules. DCS provides broad tunability with high spectral resolution, fast measurements and high brightness which enable applications which are not feasible using thermal sources. DCS has broadband spectral coverage for multispecies detection, a bright diffraction-limited source for high signal-to-noise ratio (SNR) over multikilometer ranges, a rapid update rate for immunity to turbulence-induced optical intensity fluctuations, and, importantly, can sample the transmission on a comb tooth-by-tooth basis for high-accuracy spectra.

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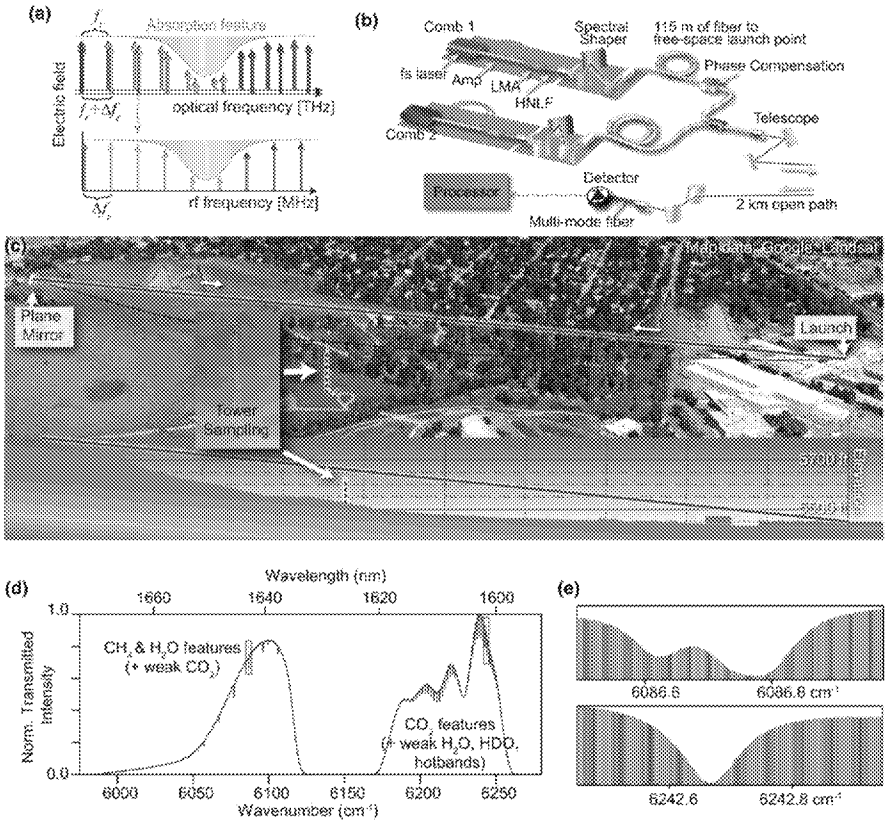

G. B. Rieker, F.

Fig. 1. Open-air path greenhouse gas sensing through dual-comb spectroscopy. (a) DCS concept: two combs with slightly different tooth spacing interfere on a detector, giving a third rf comb with a one-to-one mapping to the optical comb teeth. (The actual experiment spans ~105~105 comb teeth.) (b) Experimental setup: two combs are amplified, pulse-compressed in large mode area (LMA) fiber, spectrally broadened in highly nonlinear fiber (HNLF), and filtered to generate light covering the spectral bands of interest. Two fibers carry the comb light to the rooftop, where the light is combined and launched in a ~40 mm~40 mm beam (1/*e*21/e2diameter), and reflected from a 50 cm diameter plane mirror located 1 km distant. The return light is coupled to a multimode fiber and detected. The transmitted light power was limited to 1.5 mW so that the maximum received power was always below a conservative detector nonlinearity threshold of 50 µW average power (500 fJ pulse energy). (c) Location of the 2 km interrogation path (red line, ground projection represented by black line), the tower with the point sensor intake (inset), and elevation of the beam path (bottom inset). (d) Example transmitted intensity showing the smoothly varying comb intensity and abrupt dips due to absorption. (e) Expanded view of absorption features. The typical gas absorption lines have ~40~40 teeth across each ~4 GHz~4 GHz wide line (top, several transitions from the 2*ν*32v3 level of the CH4CH4 tetradecad; bottom, R20 transition of the 30013←0000130013←00001band of CO2CO2).

Citation

R. Giorgetta, W. C. Swann, J. Kofler, A. M. Zolot, L. C. Sinclair, E. Baumann, C. Cromer, G. Petron, C. Sweeney, P. P. Tans, I. Coddington, N. R. Newbury, "Frequency-comb-based remote sensing of greenhouse gases over kilometer air paths," Optica 1, 290-298 (2014);

https://www.osapublishing.org/optica/abstract.cfm?uri=optica-1-5-290

Description: Dual frequency-comb spectroscopy (DCS) for detection of suite of chemicals with high spatial and temporal resolution. Current DCS technologies are based on probing molecules in the mid infrared region of the spectrum which is the fingerprint region of most molecules. DCS provides broad tunability with high spectral resolution, fast measurements and high brightness which enable applications which are not feasible using thermal sources. DCS has broadband spectral coverage for multispecies detection, a bright diffraction-limited source for high signal-to-noise ratio (SNR) over multikilometer ranges, a rapid update rate for immunity to turbulence-induced optical intensity fluctuations, and, importantly, can sample the transmission on a comb tooth-by-tooth basis for high-accuracy spectra.

Figures (Ref.): Chemical sensing of greenhouse gases with measured spectra span of 80,000 comb teeth covering 5990 to 6260 cm−16260 cm−1 (1600 to 1670 nm) with absorbance noise below $5\times10^{-45}\times10^{-4}$. Data are acquired at the comb-tooth separation of 0.0033 cm^{-1} 0.0033 cm^{-1} (100 MHz), with negligible instrument line shape since the comb teeth are essentially delta functions in frequency.

Characteristics:

1. Primary Data Type: Range resolved concentration.
2. Result Type: Spatially resolved concentration (ppm) and emission rates using dispersion modelling using onboard meteorological data (temperature, pressure, humidity and wind speed).
3. Detection Range: Variable long path remote sensor
4. Specificity/Interference: High Selectivity, Ultra-High spectral (sub-nm) resolution and specificity of molecules.
5. Other Benefits. Can be made into an array with potential to detect: Simultaneous detection of other hydrocarbons, thus distinguish thermogenic or biogenic methane sources. greenhouse gases in the wide spectral range e.g. CO2, CO, N2O.
6. Measurement intermittency. Continuous
7. Measurement temporal resolution: Intermittency: Continuous.
8. Measurement Time: Depends on design, can be 1 – 100 minutes required precision- Scan rate of 1 MHz- 100 MHz (Time resolution ~ 1 µs) with 10 sec. averaging for 10 ppbv precision of methane (See Fig. 2).
9. Size. Small A few inches on a side.
10. Deployment Method. Sensors are relatively small, and can be placed in a wide variety of locations, just need a place and means of affixing them.
11. Size: Breadboard prototype, fully automated.
12. Deployment Method: Fixed, fence line
13. Working Distance: ~ 100 m – 1 Km.
14. Environmental Limitation: None, temperature, humidity accounted in calibration.
15. Calibration Procedure: Reference Cell.
16. Maturity/TRL: Research/ few commercial instruments available.
17. Durability: Currently a research based field instrument. Technology is still in research stage however there are commercial frequency comb spectrometers currently available at IRSweep Inc. (www.irsweep.com).

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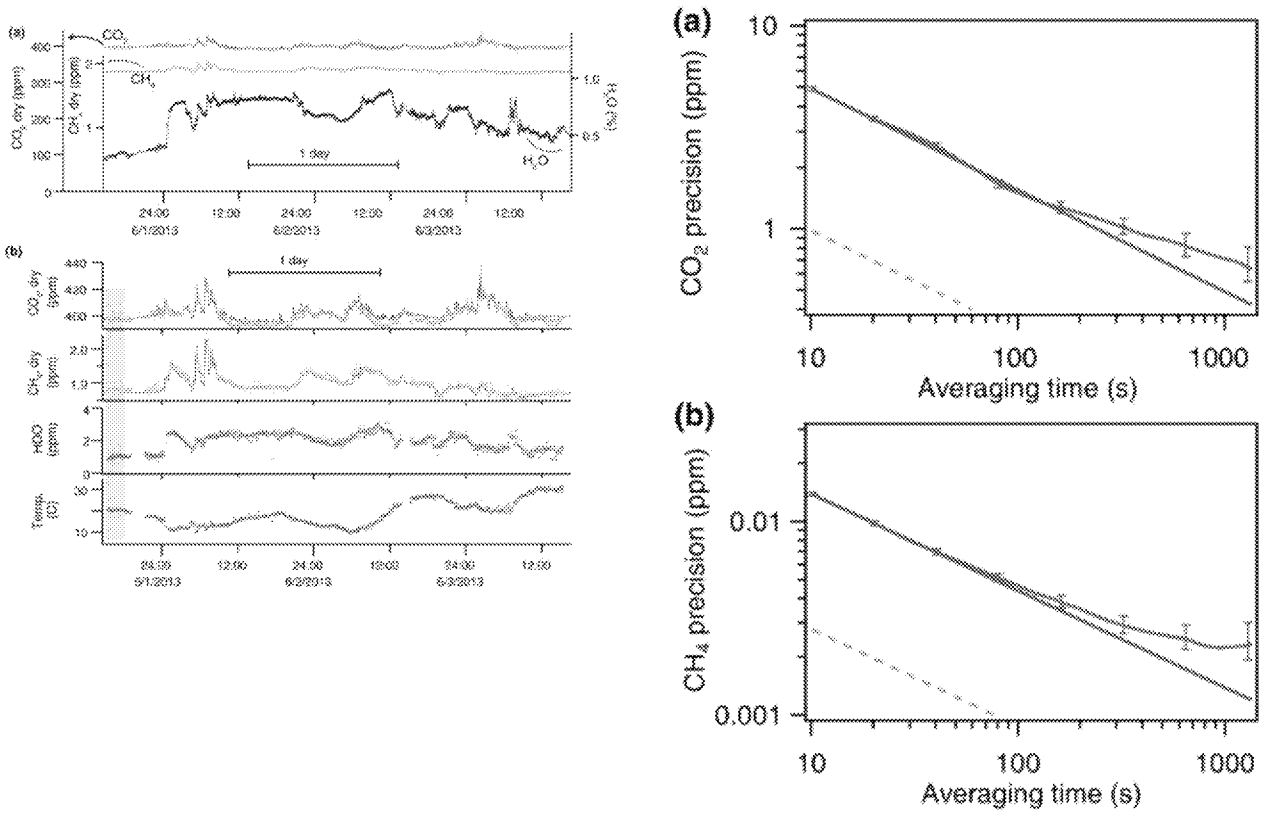

Fig. 2 Time-resolved mole fractions. (a) Time dependence of the dry-air mole fraction for CO2CO2(green), CH4CH4 (light blue), and water (dark blue) retrieved from the DCS and the corresponding values from the tower-mounted point sensor (black line) at 5 min periods over three days. (b) Time dependence of CO2CO2 and CH4CH4 with an expanded y axis. Also shown are the time dependence of HDO (pink) and the retrieved path-averaged temperature (orange). All data are from the fit with the absorption model based on HITRAN 2008. The DCS CO2CO2 mole fraction has been scaled to remove the 2.8% offset between the DCS and the tower-mounted sensor over the initial ~3 h~3 h period (shaded region) where the atmosphere was well-mixed and the measurement path was upwind from the NIST central utility plant.

Citation

G. B. Rieker, F. R. Giorgetta, W. C. Swann, J. Kofler, A. M. Zolot, L. C. Sinclair, E. Baumann, C. Cromer, G. Petron, C. Sweeney, P. P. Tans, I. Coddington, N. R. Newbury, "Frequency-comb-based remote sensing of greenhouse gases over kilometer air paths," Optica 1, 290-298 (2014);

Mode of Use: The technology is based on an electrically-pumped semiconductor laser that produces frequency comb integrated into a single few millimeter long laser diode and emits many highly stable wavelengths at the same time. DCS measurements are partially based on absorption spectroscopy where one frequency comb interacts with the sample, e.g. molecules in open air. The frequency and intensity of the transmitted light is No specific minimum working distance; max working distance determined by limit of detection.

1. Environmental Limitations. High humidity can be challenging for the type and concentration of chemical species in the sample. The acquisition of all wavelengths is performed simultaneously by coherent detection by heterodyning with a second frequency comb.

References: G. B. Rieker, F. R. Giorgetta, W. C. Swann, J. Kofler, A. M. Zolot, L. C. Sinclair, E. Baumann, C. Cromer, G. Petron, C. Sweeney, P. P. Tans, I. Coddington, N. R.

More testing will be required before operational calibration requirements are finalized – likely to include relatively frequent 'baseline' calibrations using the electrical circuitry, as well as

occasional calibration by flowing a known concentration of gas, or a series of gases, over the sensor for a short period of time.

2. Maturity/TRL: Research/Feasibility stage – TRL 4
3. Durability, Service Factors, and Calibration and Maintenance Requirements. More testing with finalized sensors will be required before exact durability, service factors, calibration, and maintenance requirements are determined.

Mode of use: The sensors can be affixed to a variety of surfaces or attached to poles surrounding operations. As the wind direction shifts, a methane plume will be transported in the direction of the sensor. The sensor will read a concentration increase in ambient methane. A number of these sensors can be distributed across a wellhead, pipeline, compressor station, or other oil and gas operations. Combining the signals may provide information about the source and magnitude of the emission.

Figure 2: Boxes representing point sensors consisting of carbon nanotubes.

Newbury, "Frequency-comb-based remote sensing of greenhouse gases over kilometer air paths," Optica **1**, 290-298 (2014); https://www.osapublishing.org/optica/abstract.cfm?uri=optica-1-5-290

Gustavo Villares, Andreas Hugi, Stéphane Blaser & Jérôme Faist, "Dual-comb spectroscopy based on quantum-cascade-laser frequency combs", Nature Communications 5, Article number: 5192 (2014) doi:10.1038/ncomms6192

4.2.2.8 Laser absorption spectroscopy

Laser absorption spectroscopy (LAS) is a well-known technology developed over the last few decades for detection of methane and several other gases. The technique utilizes the wavelength-dependent absorption of laser light to quantify the concentration of any gas in a mixture.

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Furthermore, the amount of light depends on the specific gas, gas concentration, wavelength and total path length over which this light goes through the medium (air). There are several methods of magnifying the optical path length to improve the sensitivity of these sensors. This technique is extremely versatile and several variants of this technique have evolved over time. Typical wavelengths for methane are 1.6um and 3.3um. Tunable Diode Laser Absorption Spectroscopy (TDLAS) is a method of scanning the laser wavelength around the specific absorption line. This method significantly increases the signal to noise ratio and sensitivity.

The infographic below (Fig.) shows some common variants of LAS.

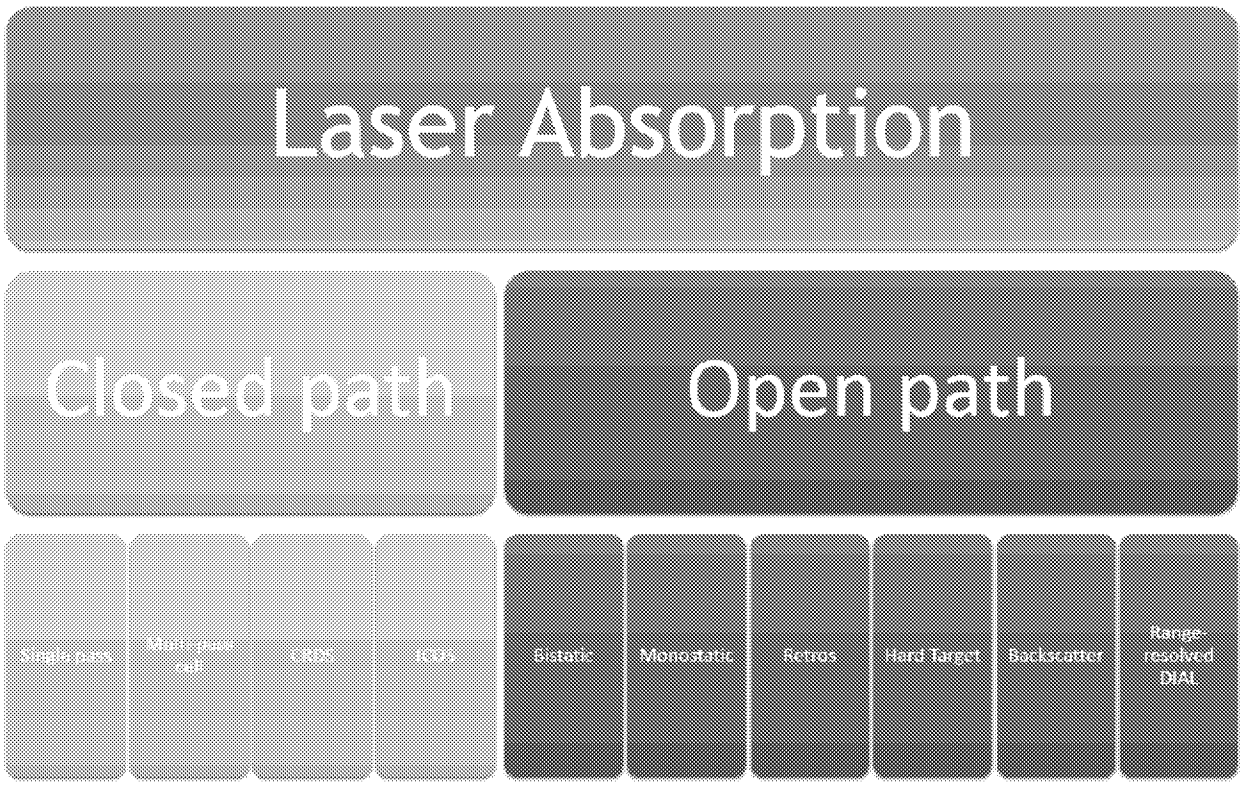

Fig 4.3 Open and Closed Paths

The unique characteristics of the different variants are described below:

4.2.2.9 Closed Path

4.2.2.9.1 Single-Pass Tunable Laser Absorption Spectroscopy

Description:

This is the simplest mode configuration of a closed path laser absorption detection strategy. In this mode, the laser is directly transmitted through a medium gas sample cell and detected after light absorption a single pass. The light absorption is dependent on the concentration of the detected species. That is used to measure the concentration of methane. and path length of the sample cell.

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Characteristics:

1. Primary Data Type: PathDigital data signal
2. Result Type: Quantitative gas concentration.
3. Range (working distance): Variable, depends on the path length of absorptionPoint measurement
4. Measurement Time: Up to kHz
5. Calibration Procedure: a. Using a calibration cell; b. calibration gasCalibration-free operation possible
6. Maturity/TRL: Mature
7. Environmental limitations: Electronics are subject to environmental damage
8. Specificity/Interference: Design-specific; Interference can be avoided minimized from all other atmospheric interference by design choice.

Mode of use:

The implementation of this technology is very straightforward. The spectrum of methane /and possible interferers are obtained during the design phase. The absorption depends on the path length "L" as shown in figure. The calibration process, if it is necessary, uses a static cell of known concentration methane.

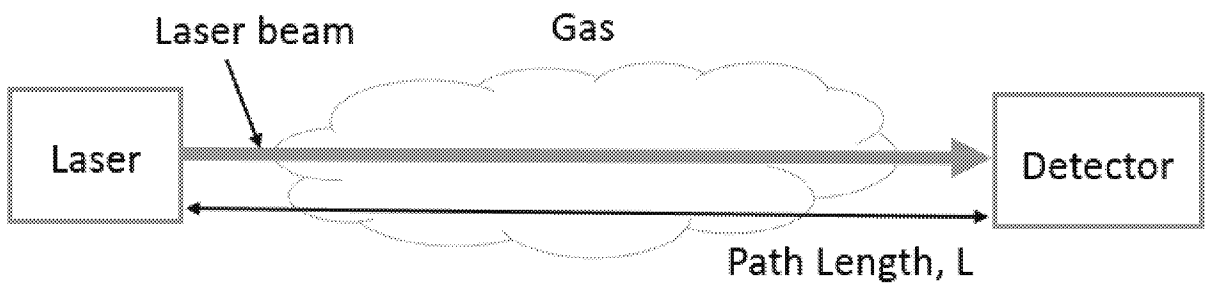

Fig. 4.4 Schematic for a basic tunable laser absorption spectroscopy setup.

4.2.2.9.2 CRDS

Description:

Cavity Ring Down Spectroscopy (CRDS) is a variant where the a significantly enhanced path of absorption is obtained by use of an optical setup consisting of two high reflectivity mirrors. The path enhancement is achieved by trapping the light between two mirrors until a certain level of desired path length amplification is obtained. The basic prinicple of operation is based on the fact that light bounces back and forth several times between the mirrors until the light is either absorbed or leaks through the high-reflectivity mirrors. The absorption in the cell is quantified from time-resolved "ring-down" signals in the optical cavity with and without the absorbing gas. This magnification factor is directly influenced by the reflectivity of the mirrors. This mirror is therefore prone to sensitivity to environmental factors that may alter the magnification factor.

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Characteristics:

1. Primary Data Type: Point concentration Digital data signal
2. Result type: Quantitative gas concentration
3. Range (working distance): Local Point measurement; no range
4. Measurement Time: ~ 1 Hz to 100 Hz
5. Calibration Procedure: By introduction of known concentration mixture in the cell calibration gas
6. Maturity/TRL: Mature
7. Environmental limitations: detection sensitivity are subject to environmental conditions
8. Specificity/Interference: Design-specific; Interference can be avoided minimize from all other atmospheric interference by design choice.

Mode of use:

A typical schematic for a CRDS setup is shown in Fig. The high-reflectivity mirrors are used to amplify the detection sensitivity. The effective path of absorption for CRDS is effectively multiplied by a gain factor, G. This results in enhanced sensitivity of methane detection. Typically, an ultra-long path of a km can be achieved. This enables detection of sub-ppm sensitivity and also isotopic characterization, useful for source attribution.

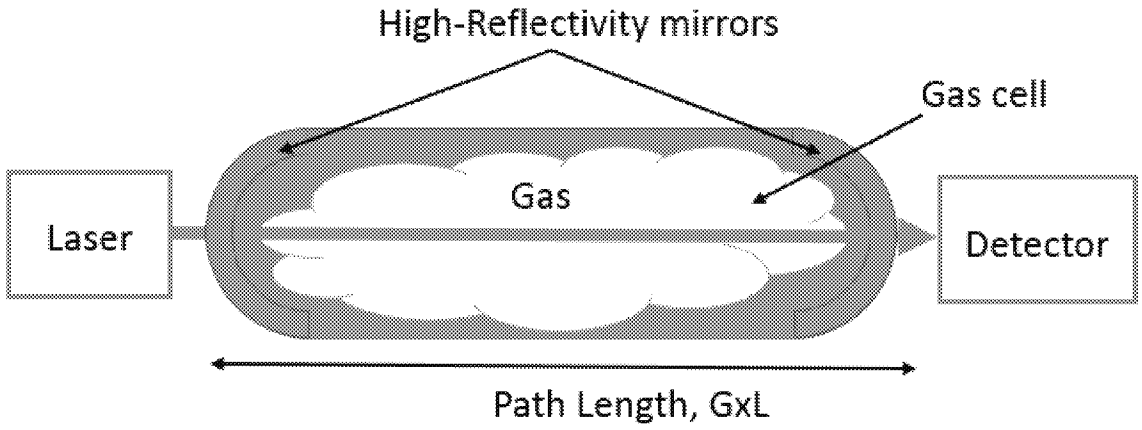

Fig.4.5 Schematic for a basic CRDS setup.

4.2.2.9.3 ICOS

Integrated Cavity Output Spectroscopy (ICOS) is another path amplification technique with high-reflectivity mirrors with a more robust noise performance. Instead of using the cavity ring down time, the light is bounced back and forth between the high-reflectivity mirrors as a continuous stream and wavelength is scanned fast enough to avoid cavity resonance noise. This enables scanning of laser wavelength and can be used to resolve spectral shapes of methane and correct for interference to an extent. 4.5A.3. .

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of photons and laser wavelength is scanned fast enough to avoid cavity resonance noise. However, this technique is also susceptible to long term drifts and hence frequent calibration is required.

Characteristics:

1. Primary Data Type: Point Digital data signal
2. Result Type: Quantitative gas concentration
3. Range (working distance): LocalPoint measurement; no range
4. Measurement Time: ~ 1 Hz
5. Calibration Procedure: Calibration gas
6. Maturity/TRL: Mature
7. Environmental limitations: detection sensitivity are subject to environmental conditions
8. Specificity/Interference: Design-specific; Interference can be minimized from atmospheric interference by design choice.

Mode of use:

Very similar to the mode of operation as CRDS.

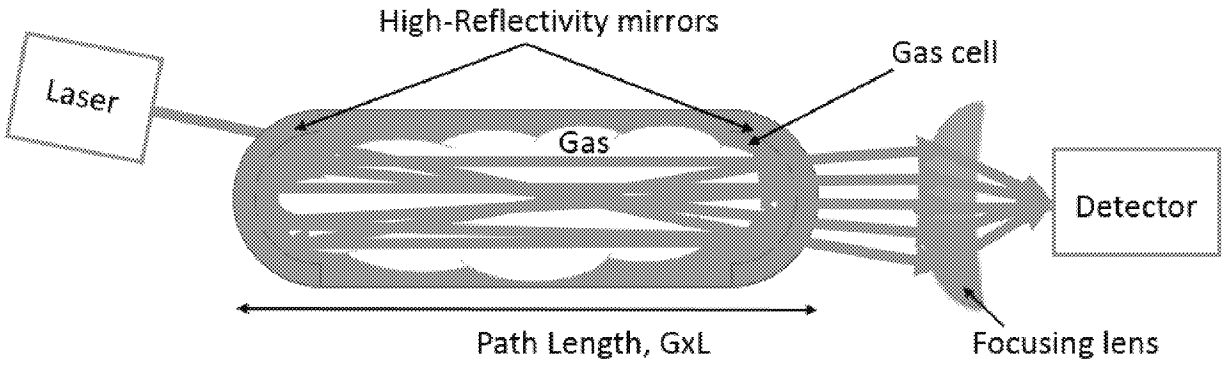

Fig. Schematic for a basic ICOS setup.

Mode of Use:

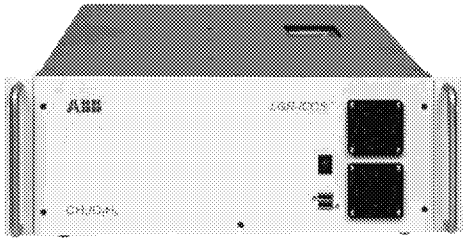

Figure x: ICOS system packaged for mobile leak survey. Source: ABB

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4.2.2.10 Multi-pass Tunable Laser Absorption Spectroscopy

In this method, path amplification is achieved by reflection between high reflectivity mirrors as well. However, the light travels a unique path between the input and output. This makes the sensors uniquely more robust than the other two cavity techniques. However, the path amplification achieved is lower . This leads to a reduced sensitivity depending on the path length.

Characteristics:

1. Primary Data Type: Point concentration
2. Result Type: Quantitative gas concentration
3. Range (working distance): Point measurement
4. Measurement Time: > 1 kHz
5. Calibration Procedure:– a) calibration gas
6. Maturity/TRL: Mature
7. Environmental limitations: dust and vibration may reduce sensitivity
8. Specificity/Interference: Design-specific; Interference can be minimized from atmospheric interference by design choice.

Mode of use:

Similar to the other cavity techniques, The highest resolution spectrum can be achieved because of their insensitivity to laser-wavelength scan rates, enabling more precise inter-species spectral demultiplexing and data reduction schemes, such as wavelength modulation spectroscopy.

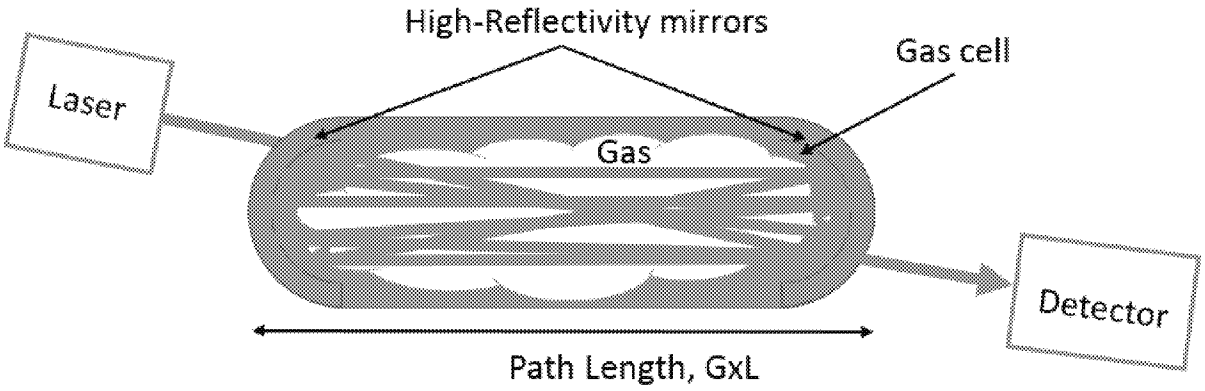

Fig. Schematic for basic multi-pass tunable laser absorption spectroscopy.

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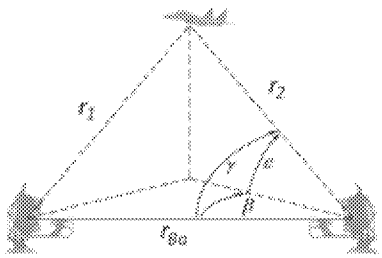
4.2.2.10.1.1 Open Path Tunable Laser Absorption Spectroscopy

Open path tunable laser absorption spectroscopy techniques are based on the laser path being open to the atmosphere. The path can be either fixed in distance or variable depending on the instrument and mode of operation. This method has several advantages;

1. Fast response to highly variable gas plumes
2. Coverage of a large area
3. High sensitivity
4. Methane specific
5. There are several different methods deployed in open path systems as described below.

4.2.2.10.1.2 Bistatic

In a bistatic open path system, the laser is launched down range to a reflective surface, the reflected light is then angled to a separate receiver. The laser transmitter and receiver are located in two separate fixed locations. In theory, a laser fence can be set up around a facility. In this configuration, precise alignment and highly reflective mirrors (retro-reflectors) are used to obtain a long path length.



<<Figure Title>>

4.2.2.10.1.3 Monostatic

In a Monostatic open path system, the laser is launched down range to a reflective surface, the reflected light then returns to the launch position. The laser transmitter and receiver are located in the same fixed position. The effective path length is thus doubled resulting in increased sensitivity. Depending on the desired distance to cover, simple reflective surfaces to highly precise retro-reflectors are used. Monostatic systems are easier and more cost effective to deploy than Bistatic systems.

Monostatic designs can be either short paths or long paths. Short paths systems are useful for making point measurement. Long path systems are capable of detecting leaks which may occur along its path or to integrate the concentration of a large distance.

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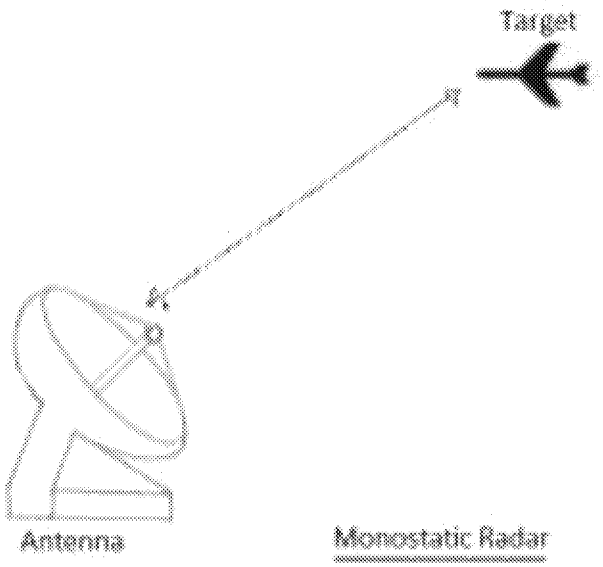

Figure Title

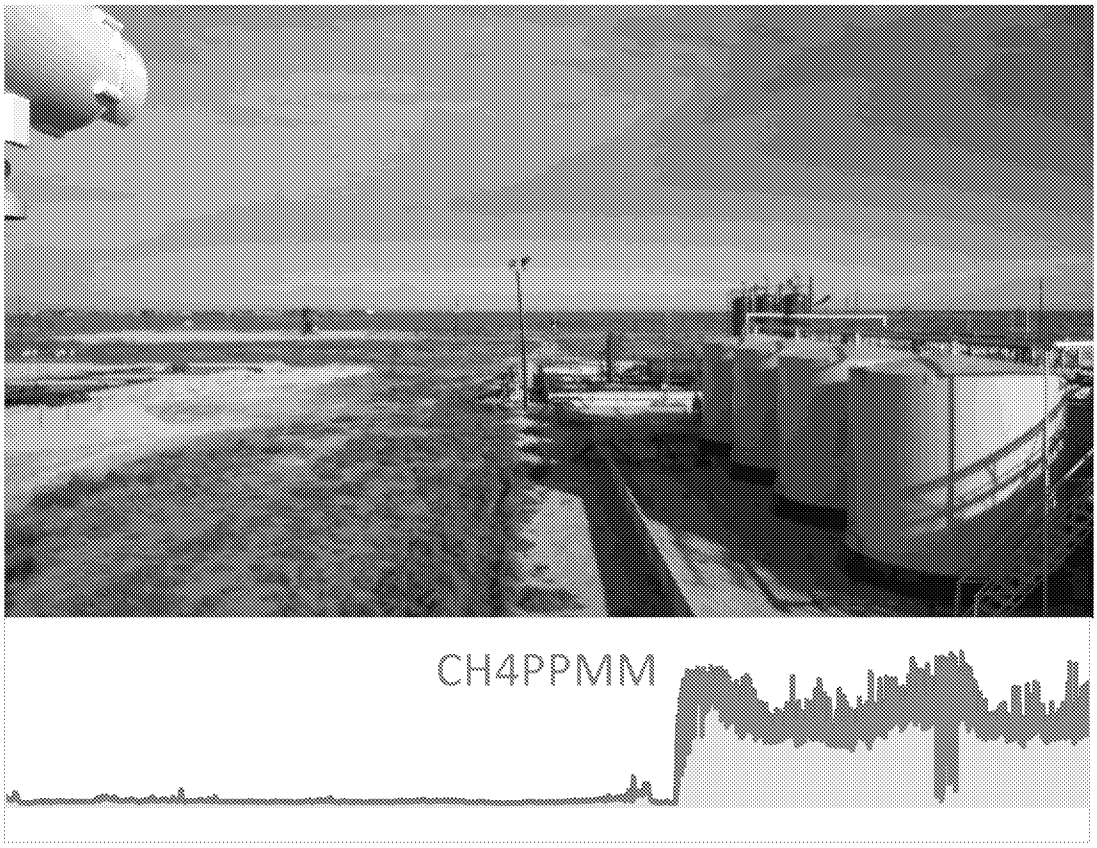

Figure x: Open path laser adjacent to an oil tank battery. Open thief hatch easily detected. Source: RMLD-REM, Heath Consultants;

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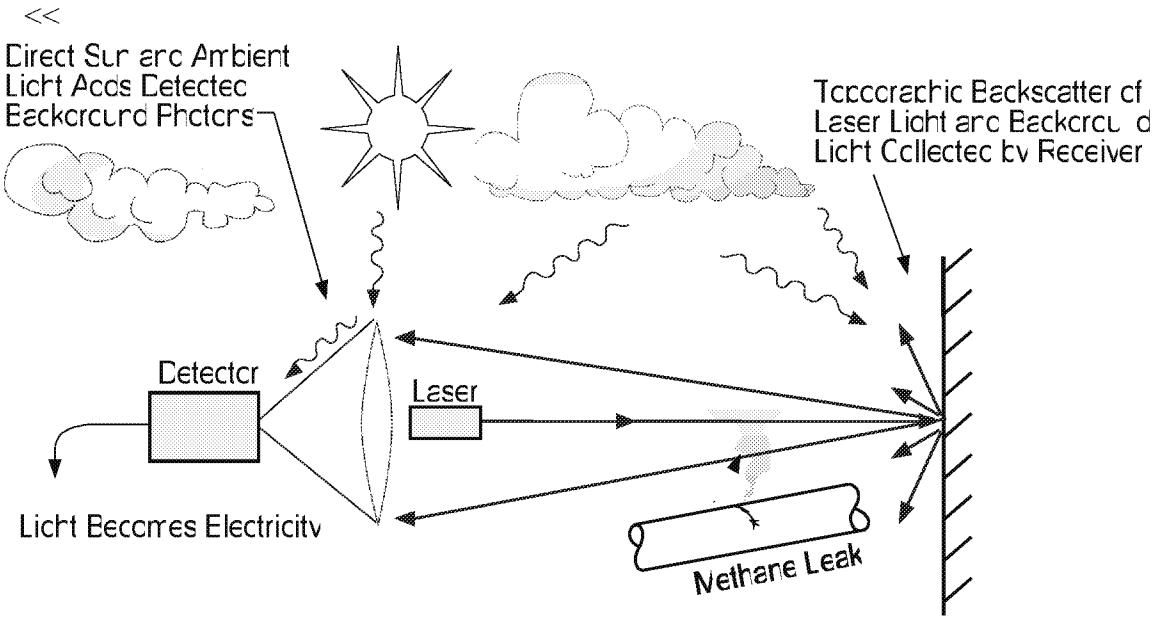
4.2.2.10.1.4 Backscatter

Backscatter is a special case of monostatic. The primary difference is that the natural background is used to reflect back the laser light. Backgrounds could be the ground, foliage, metal structure, etc. Natural backgrounds are not efficient reflectors, most of the light is scattered in all directions. Only a portion of the light is directed back to the receiver. As a result, the scanning distance is often much shorter than when using efficient reflectors.

Portable handheld instruments are based on the backscatter method. The advantage is the ability to scan an area or components rapidly.

Figure x: Portable handheld laser used for methane leak surveys and detections. Source: RMLD-IS, Heath Consultants.



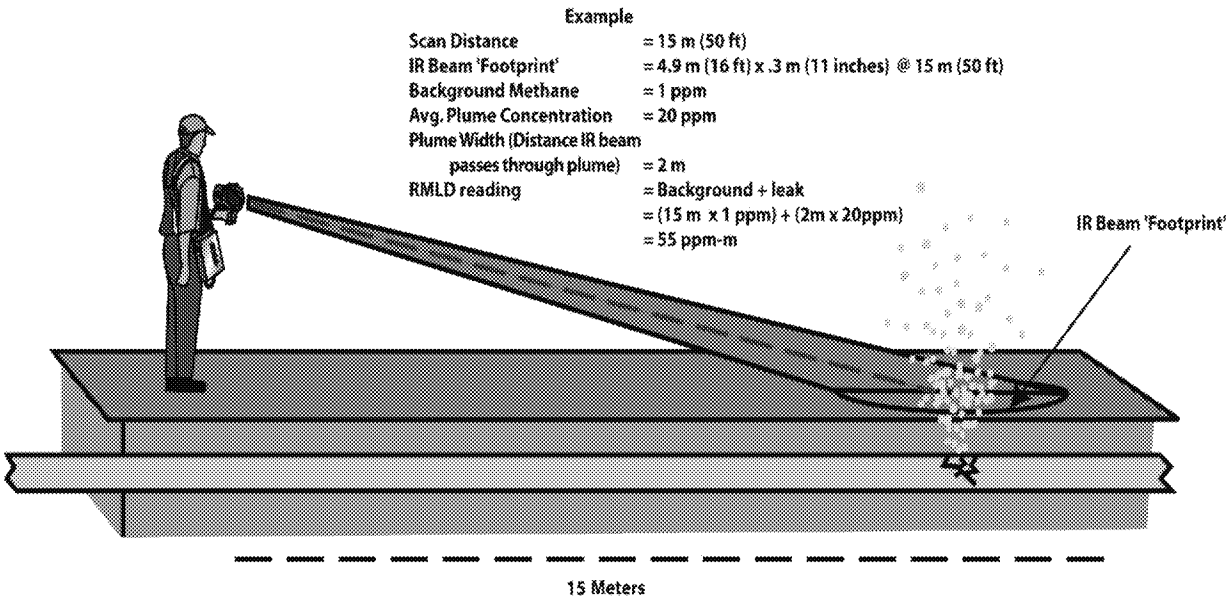


Figure x: Illustration of laser backscattering and leak detection using a scanning laser. Source: Heath Consultants, Physical Science Inc.

4.2.2.10.2 Range Resolved DIAL

In this configuration, powerful lasers are used to provide a gradient concentration over the path length. The gradient is measured by reflecting two laser wavelengths off of aerosols and particles in the ambient air along its measurement path. The absorption wavelength is keyed to the compound of interest, while the off absorption feature wavelength is used to measure the decay in strength of the absorption laser signal over distance. The range is resolved by a function of time. The measurement path is usually rotated in order to provide a complete map of the plume.

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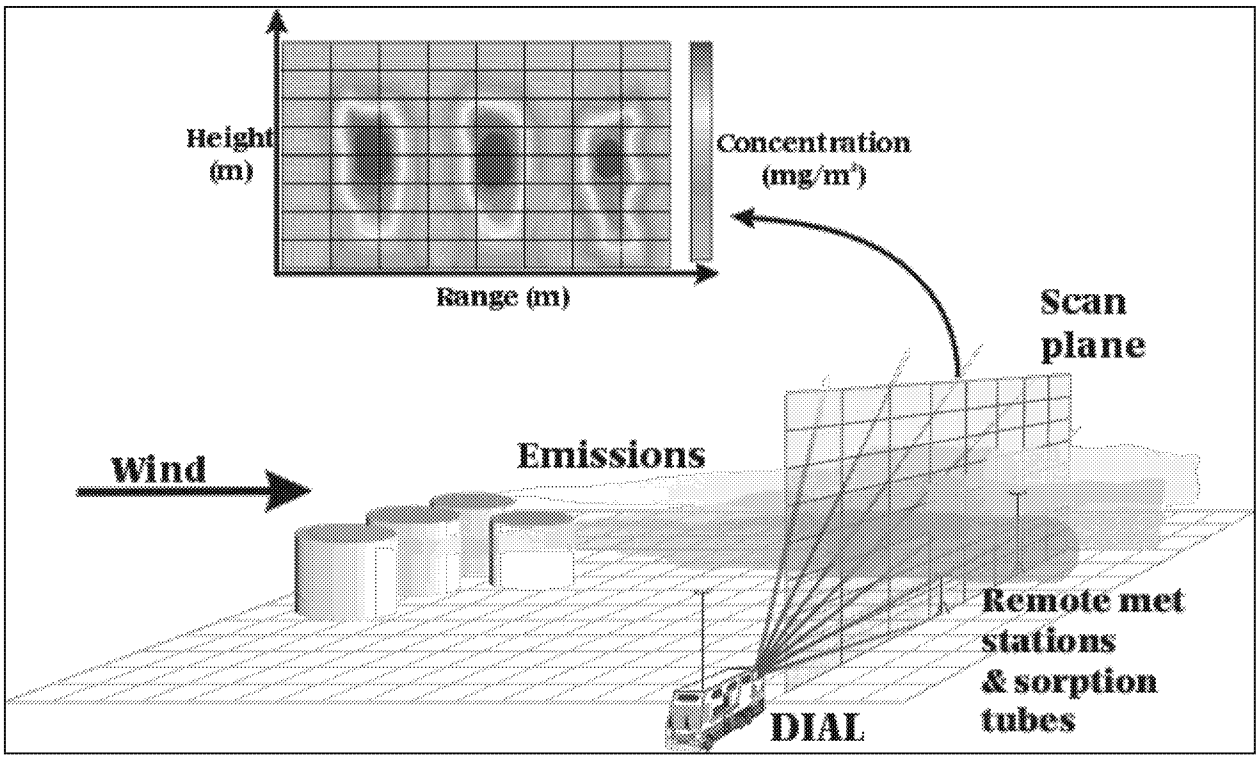

4.2.2.11 Etalon

Description:

Etalon based gas sensors are based on the Fabry–Pérot effect of birefringence crystals in creating interference pattern. Through the use of Etalon crystals, specific interference patterns are created that match multiple absorption lines (signature) of the target gas. Matching multiple absorption lines increases the sensitivity and cross speciation rejection. Making Etalon based gas sensor highly selective to methane. Recent technology advances have enabled the development of low cost, low power detectors. Etalon based gas sensors are widely used by LDC's to conduct compliance leak surveys. Systems have been deployed that are mobile vehicle mounted and hand held portables.

The optical system is composed of a high intensity light source (typically is broad in spectrum), optical band pass filters to reduce the light energy to the specific band of interest (3.3um for methane); polarizers, and photo detector. In order to alternate the birefringence pattern between the"on" gas spectrum and "off" spectrum a means to modulate the light is necessary. The modulation of the light spectrum significantly increases the sensitivity and rejection of interference gases.

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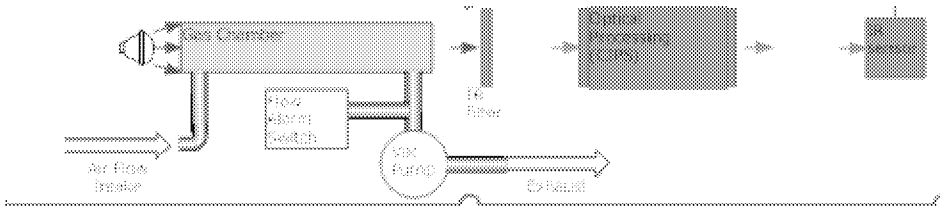
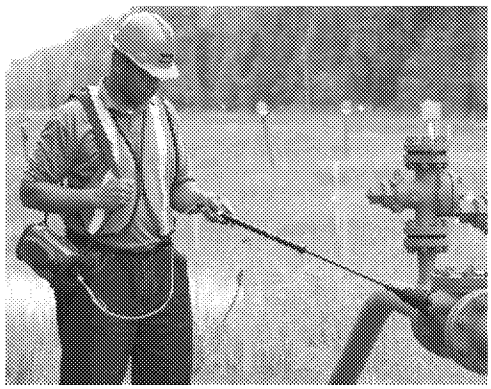
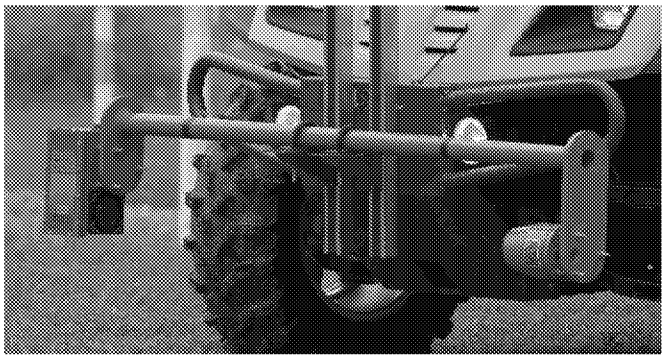


Figure - absorption spectrum showing multiple lines?





Characteristics:

1. Primary Data Type: Path concentration
2. Result Type. Quantitative gas concentration
3. Detection Range: .2ppm to 2000ppm
4. Specificity/Interference: Highly specific; Interference can be minimized from atmospheric interference by design choice.
5. Other Benefits. Cost effective for the achieve level of sensitivity and speciation
6. Measurement intermittency. Continuous
7. Measurement temporal resolution: kHz
8. Size. From handheld to vehicle mounted
9. Deployment Method. Fixed, portable, mobile
10. Working Distance. Point measurement
11. Environmental Limitations. No specific limitations.
12. Calibration Procedure: built in calibration cell typical; operational temperature calibration is performed as needed.
13. Maturity/TRL: Mature
14. Durability, High durable. Systems deployed as early as the mid 90's are still in operational use.

Mode of use:

Open path; In this configuration, the light transmitter and receiver are positioned in a direct path open to the atmosphere. In a mobile application, the vehicle will drive through the gas plume causing the optical path to intersect the plume, giving a detection. In portable models, a probe is moved along the ground or along components drawing in a gas sample. As the gas passes through the sample cell, a gas detection results.

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4.2.2.12 Optical Gas Imaging (OGI)

This section offers an overview of Optical Gas Imaging (OGI) technology for the purpose of Methane gas detection. This section also provides accepted application of OGI technology for regulatory compliance initiatives and voluntary applications.

There are two types of approaches to optical gas imaging cameras that includes, Active IR imaging and Passive IR imaging. Passive IR imaging cameras uses available ambient IR radiation to detect intensity differences between the ambient background IR and the gas plume radiation. Active IR imaging uses an IR light source (i.e., infrared laser) that is projected toward the area of interest, this projected IR light is then reflected off a background, and is absorbed or attenuated as it encounters a gas species along the optical path. The reflected attenuated infrared light signal is then captured by an infrared detector.

4.2.2.12.1 Passive IR Imaging

4.2.2.12.1.1 Mid Wave IR (4.2.1.9.2)

Optical Gas Imaging technology is a specialized infrared camera developed for the purpose of visualizing gas leaks that cannot be seen by the naked eye. Simply, these cameras are comprised of an IR transmissive lens system, an infrared responsive image sensor (i.e., the detector, focal plane array), a cooling system, a display screen or viewfinder, and integrated electronics that provide capabilities for image processing and analytics, memory storage, wireless communication, just to name a few. For methane gas detection using OGI cameras the commonly used infrared detector is a cooled Indium Antimonide (InSB) image sensor detector that is integrated with 3.2 μm to 3.4 μm bandpass filtering optics specially designed for imaging hydrocarbon gases. It should be noted that OGI imaging cameras designed for wavelengths within this range may also detect other hydrocarbon gases as they exhibit absorption peaks within this range. OGI cameras are generally recognized not to have the capability to differentiate between various species of detectable hydrocarbon gases. It should be noted that there are variations of mid wave IR Optical Gas Imaging cameras that are designed for the detection of other specific gases such as Carbon Monoxide (4.52 μm – 4.67 μm). Additionally, optical gas imaging cameras can take various configurations that include hand-held cameras, portable cameras using a mobile stand, and fixed installed cameras within a facility.

Applications

Optical gas imaging technology has been recognized, validated, and approved for use in meeting regulatory compliance reporting requirements by the EPA and by certain states. Additionally, the Oil & Gas Industry has found expanded use for optical gas imaging camera technology in applications related to leak troubleshooting, preventative maintenance, and in taking various voluntary measures. These applications for OGI technology along the Oil & Gas value chain are expansive starting with upstream operations (e.g., well-sites, compressor stations, gas plants), mid-stream (e.g., gathering/distribution, energy), downstream (e.g., refining, petro-chemical).

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Table Summarizing Examples of Applications of OGI for Federal & State Regulations

Sources covered by the 2012 New Source Performance Standards (NSPS) for VOCs and the 2016 NSPS for Methane and VOCs, by site				
Location and Equipment/Process Covered	Required to Reduce Emissions Under EPA Rules	Rules that Apply		
		2012 NSPS for VOCs*	2016 NSPS for methane	2016 NSPS for VOCs
Natural Gas Well Sites				
Completions of hydraulically fractured wells	✓	*	*	
Compressors				
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Oil Well Sites				
Completions of hydraulically fractured wells	✓		*	*
Compressors				
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Production Gathering and Boosting Stations				
Compressors	✓	*	*	
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps				
Storage tanks	✓	*		
Natural Gas Processing Plants				
Compressors	✓	*	*	
Equipment leaks	✓	*	*	
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Natural Gas Compressor Stations (Transmission & Storage)				
Compressors	✓		*	*
Equipment leaks	✓		*	*
Pneumatic controllers	✓		*	*
Pneumatic pumps				
Storage tanks	✓	*		

* Note: Types of sources already subject to the 2012 NSPS requirements for VOC reductions that also are covered by the 2016 methane requirements will not have to install additional controls, because the controls to reduce VOCs reduce both pollutants

Characteristics

1. Maturity: Mature
2. Working Distance: as close as allowed by procedural safety policies. Generally used at 15 feet to 150 feet.
3. Calibration: As required by EPA and state level regulations and as required per manufacturer requirements.
4. Methane Detection: Camera bandwidth that detects between 3.1 µm to 3.5 µm wavelength.
5. Measurement time: adequate to support efficient LDAR activities.
6. Interference: Environmental interference from fog, rain, snow.
7. Multi-Spectral & Hyper-spectral Imaging
8. Qualitative: Tool used to visualize the location and general severity of a leak.
9. Quantification: by computational imaging techniques yet to be vetted.

Mode of Use:

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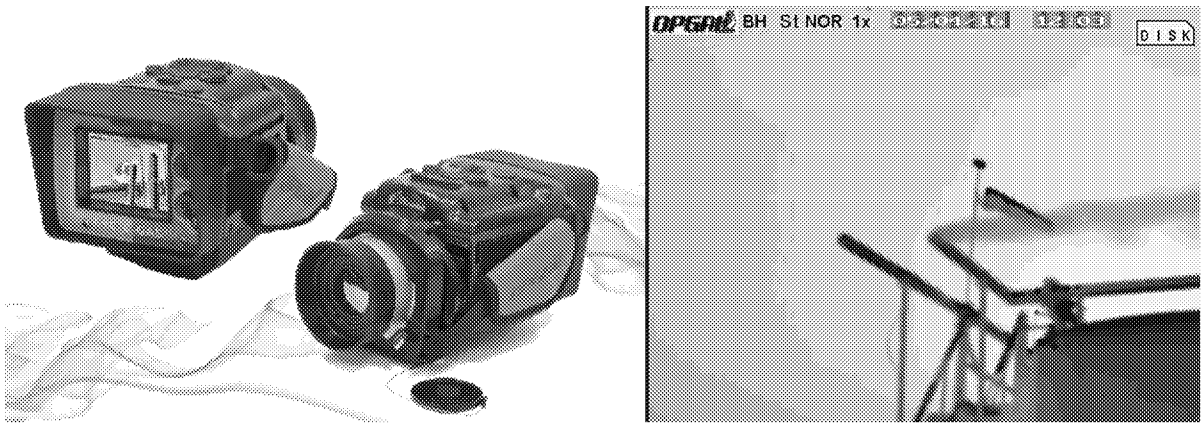

Figure x: Optical Gas Imaging Camera and image of a leak through a relief valve. Source: Opgal and Heath Consultants

4.2.2.13 Fourier Transform Infrared (FTIR) Spectroscopy

Fourier Transform Infrared (FTIR) Spectroscopy is a technologies capable of the measurement of multiple compounds (inorganic and organic) at once in real-time. The technique utilizes the wavelength-dependent absorption of infrared light to quantify the concentration of any gas in a mixture. Furthermore, the absorption of light depends on the total path length, concentration of the gas over which this light goes through the medium (air) and the absorption coefficent of the compound. The infographic below (Fig. XX) shows some common variants of FTIR.

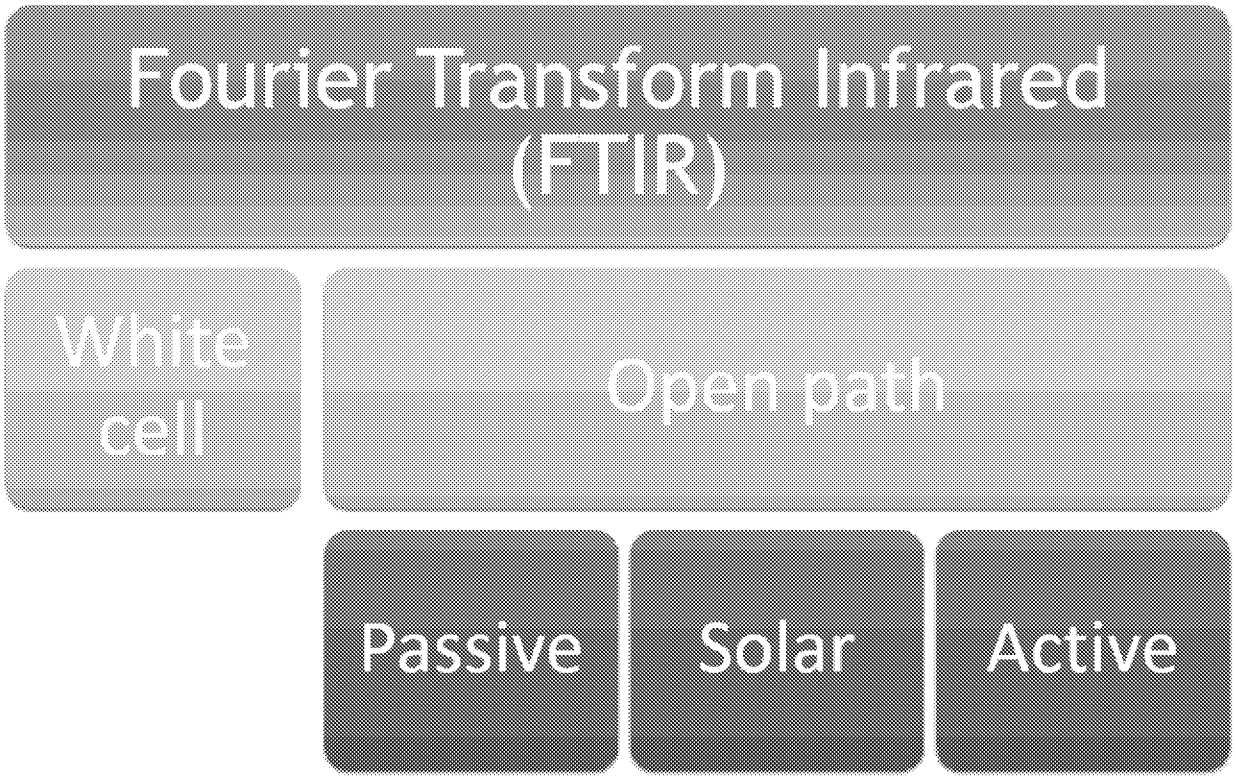

Figure Title

The basic principle of measurement uses an infrared radiation beam (generally 2.5 um to 15um wavelength) to interact with gas species in the gas which produce unique spectra patterns. The amount of the absorption can be correlated to the concentration and the path length of the interaction of the beam and the sample gas. The infrared beam is produced by an interferometer, which contains beam-splitter, laser, IR source and a set of moving and fixed mirrors. The purpose of the interferometer is to allow the measurement of all wavelengths at the same time. The fourier transform (mathematical algorithm) allows the interferogram signal (time/length domain) to be converted spectra (wavelength domain). The spectra are then used to identify and quantify the compounds in the sample gas using mathematical algorithms such as classical least squares and Beers-lambert Law, reference spectra, background spectra temperature, pressure, and path length. The path length, detectors (peak sensitivity, noise, cooling) and interferometers (spectral resolution) vary greatly depending on the need and target compounds. It should be noted that FTIR is capable of the measurement most volatile inorganic and organic compounds including isotopes(depending on concentration) and isomers with the exception of diatomic. The sensitivity of the measurements can be impaired due to large spectra interferents such as water and carbon dioxides or compounds with similar spectra fingerprints such as C4+ alkanes.

4.2.2.13.1 White Cell

In this mode of operation, the FTIR is used in a point monitor configuration. The instrument has the light source, interferometer, white cell and detector together. The sample gas is either pushed or pulled into the cell continuously or in static batches. The white cell serves as vessel to maintain the extracted sample gas at a consistent temperature and pressure, which is necessary for the use of reference spectra, and to allow the infrared radiation to be bounced multiple times through the gas in order to increase the path length for more sensitive measurements. White cells can either be a fixed or adjustable path lengths and are generally temperature controlled

1. Calibration Procedure: By introduction of known concentration mixture in the cell, dynamic spiking, calibration transfer standards with reference spectra
2. Maturity/TRL: Mature
3. Environmental limitations: Electronics and the detection sensitivity are subject to environmental conditions
4. Specificity/Interference: Design-specific; Interference can be mitigated with the proper analytical algorithms for most compounds.

4.2.2.13.2 Open Path

In this mode of operations, the FTIR is used in an open path format. This allows for infrared radiation beam to passed through the sample gas in the environment without need for sample extraction or conditioning. The Open Path FTIR instruments have several configurations such as passive, solar, monostatic and bi-static, which serve different purposes. Open path measurements generate a path averaged concentration over the path length of the measurement.

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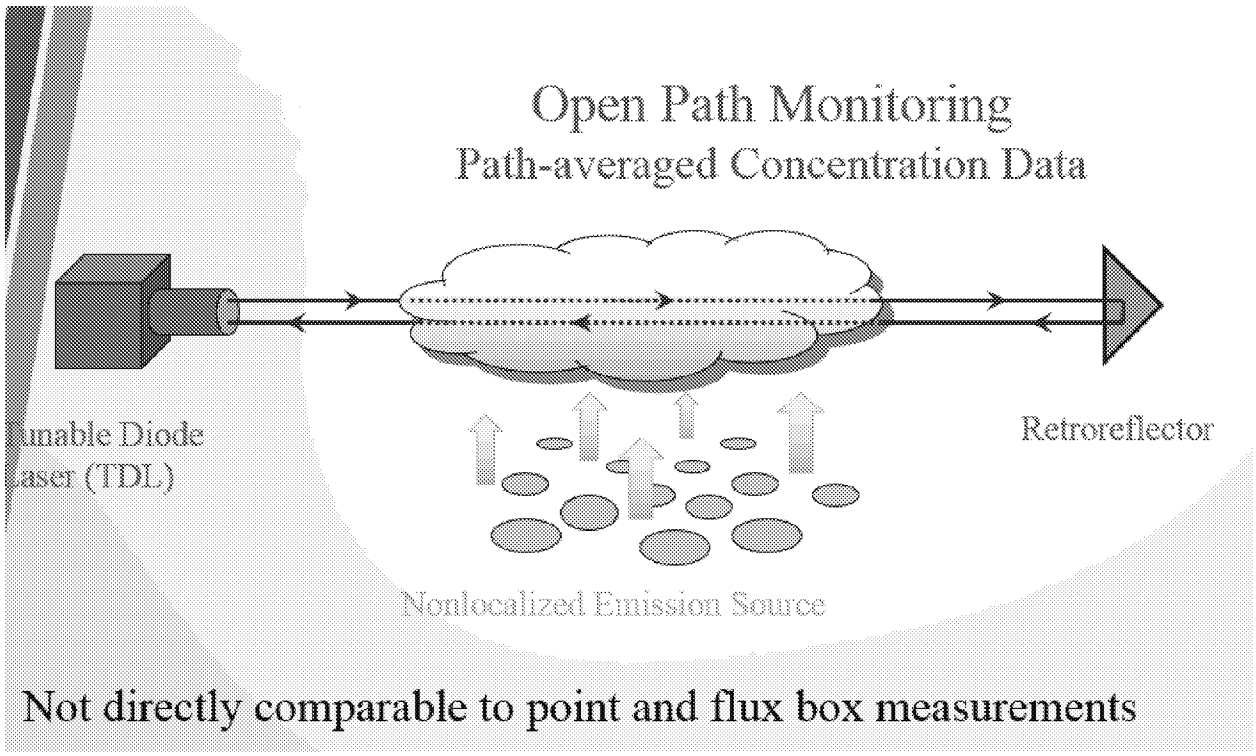

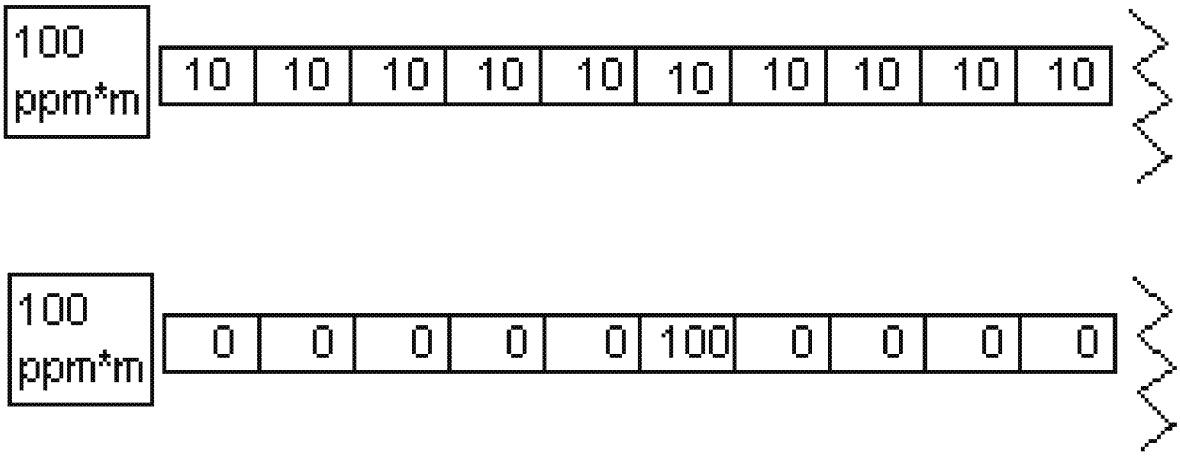

Figure Title

4.2.2.13.2.1 Passive (monostatic)

In this mode of operation, the FTIR uses an external elevated temperature source (e.g. a flame or volcano) to provide the infrared radiation. The elevated temperature gas compounds emit an infrared signature specific to their compound structure and temperature. This infrared radiation is then collected by the FTIR and analyzed. This technique must also account for the stray solar

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radiation and the compounds in the air between the elevated temperature source and the detector. The results from this technique are usually provided in a ratio of concentrations as the width of the plume is generally dynamic during measurements.

1. Specificity/Interference: Design-specific; Interference can be avoided from all atmospheric interference by design choice.
2. Environmental limitations: Electronics and the detection sensitivity are subject to environmental conditions significantly lower. This leads to a reduced sensitivity to absorption for the same methane absorption transitions.

Mode of use: Very similar to the mode of operation as CRDS.

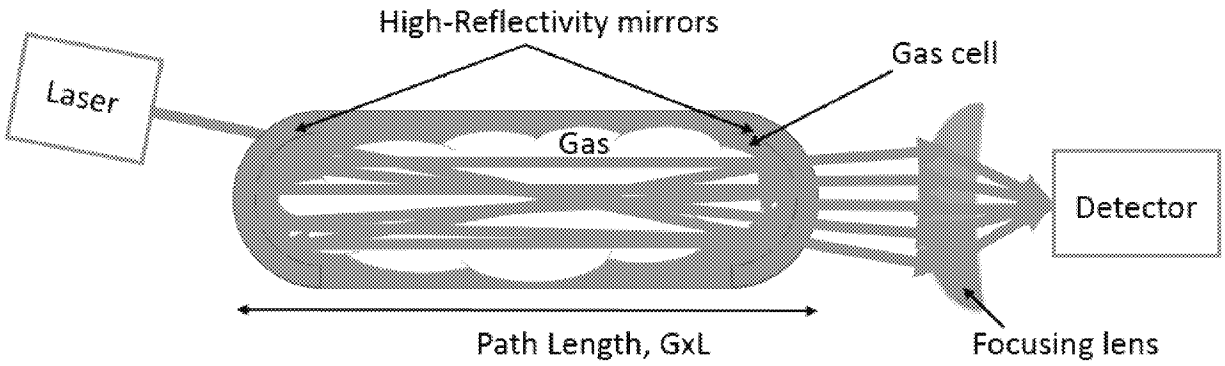
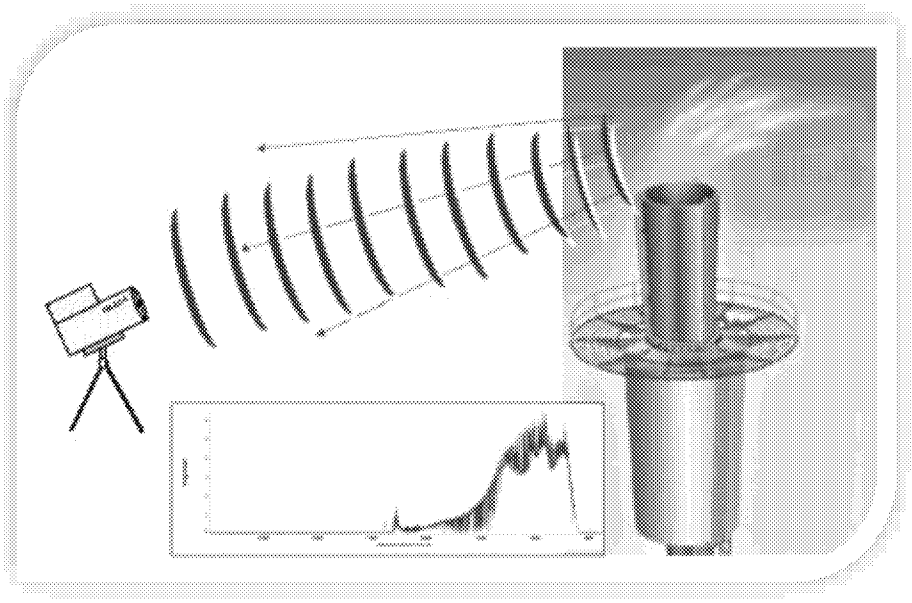


Fig. 4.6 Schematic for a basic ICOS setup.4.6 A.4. .



4.2.2.14 Solar (monostatic)

Similar to the passive, the solar FTIR uses external infrared source, the sun, for the infrared radiation. The use of the sun as a source provides information on the total air column between the FTIR and the sun. Compounds at the ground level must be determined by the spectra shape changes due to temperature and pressure within the atmosphere. There are also techniques which use the Solar FTIR (Solar Occultation Flux) in a mobile format, which can provide a background level of compounds in the total air column to understand local contribution of a source or sources.

Characteristics

1. Primary Data Type: Point concentration
2. Range (working distance): Local measurement; no range?
3. Measurement Time: ~ 0.1 to 10 Hz
4. Calibration Procedure: Various and architecture dependent – a) By introduction of known concentration mixture in the cell or b) Calibration-free modeNot possible to do primary calibration due to large measurement path
5. Maturity: Mature
6. Maturity/TRL: Not sure the nomenclature – this is past research, but not at a fully commercial push button level
7. Environmental limitations: OnlyElectronics and the electronicsdetection sensitivity are subject to environmental conditions
8. Specificity/Interference: Design-specific; Interference can be avoided from all atmospheric interference by design choice.

Mode of use: Similar to the other cavity techniques, except in calibration-free cases where calibration steps are not necessary. The highest resolution spectrum can be achieved because of their insensitivity to laser-wavelength scan rates, enabling more precise inter-species spectral demultiplexing and data reduction schemes, such as wavelength modulation spectroscopy.

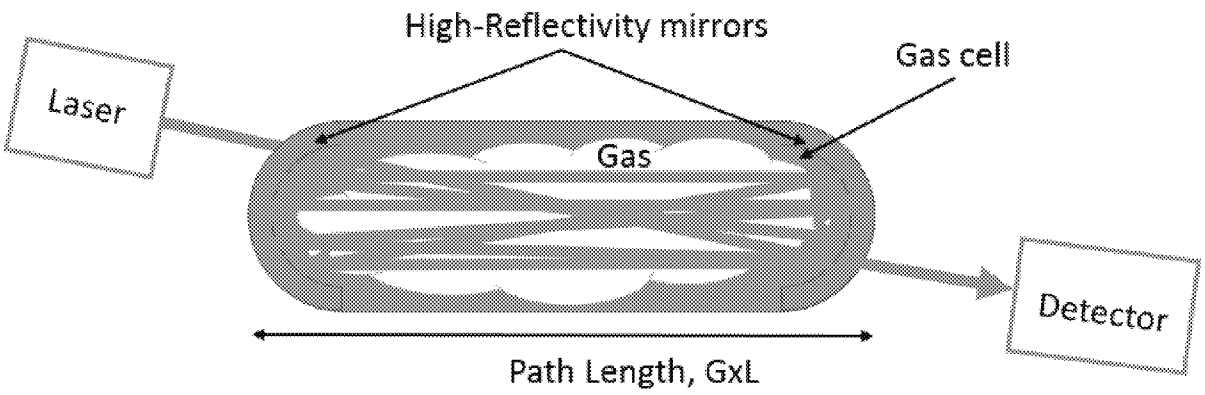


Figure Title

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4.2.2.15 Range Resolved DIAL

In this configuration, powerful lasers are used to provide a gradient concentration over the path length. The gradient is measured by reflecting two laser wavelengths off of aerosols and particles in the ambient air along its measurement path. The absorption wavelength is keyed to the compound of interest, while the off absorption feature wavelength is used to measure the decay in strength of the absorption laser signal over distance. The range is resolved by a function of time. The measurement path is usually rotated in order to provide a complete map of the plume.

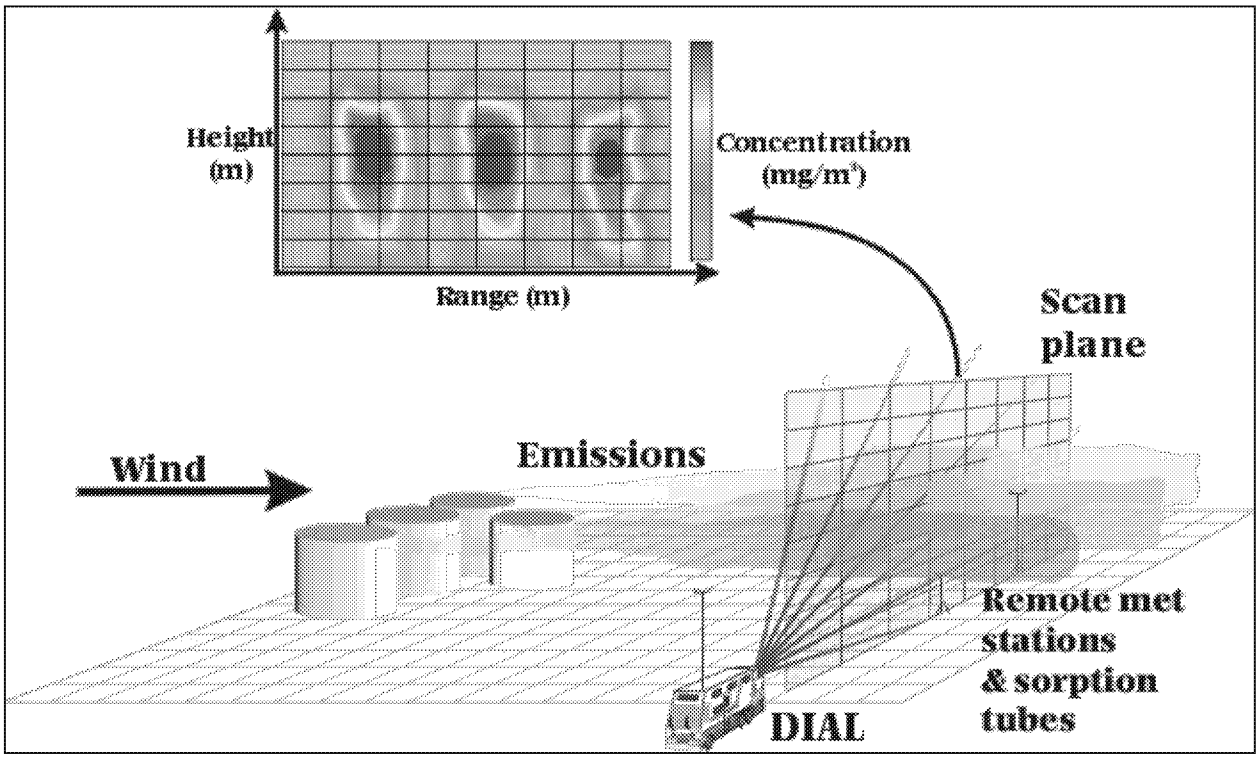

Figure Title

(4.2.1.6.7) The absorption wavelength is keyed to the compound of interest(methane),

Table(s) 4.2 Summarizing Examples of Applications of OGI for Federal & State Regulations

Sources covered by the 2012 New Source Performance Standards (NSPS) for VOCs and the 2016 NSPS for Methane and VOCs, by site				
Location and Equipment/Process Covered	Required to Reduce Emissions Under EPA Rules	Rules that Apply		
		2012 NSPS for VOCs*	2016 NSPS for methane	2016 NSPS for VOCs
Natural Gas Well Sites				
Completions of hydraulically fractured wells	✓	*	*	
Compressors				
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Oil Well Sites				
Completions of hydraulically fractured wells	✓		*	*
Compressors				
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Production Gathering and Boosting Stations				
Compressors	✓	*	*	
Equipment leaks	✓		*	*
Pneumatic controllers	✓	*	*	
Pneumatic pumps				
Storage tanks	✓	*		
Natural Gas Processing Plants				
Compressors	✓	*	*	
Equipment leaks	✓	*	*	
Pneumatic controllers	✓	*	*	
Pneumatic pumps	✓		*	*
Storage tanks	✓	*		
Natural Gas Compressor Stations (Transmission & Storage)				
Compressors	✓		*	*
Equipment leaks	✓		*	*
Pneumatic controllers	✓		*	*
Pneumatic pumps				
Storage tanks	✓	*		

* Some types of sources already subject to the 2012 NSPS requirements for VOC reductions that also are covered by the 2016 methane requirements will not have to install additional controls, because the controls to reduce VOCs reduce both pollutants.

- Table 4.23 summarizing examples of technology/applications

Technology	Data type	Sampling location	Sampling rate	Specificity/ Speciation	Working distance	Range/Accuracy	Size/ Weight	Power requirements	Safety Certifications
Forward Looking Infrared Camera	Image	Field of view		Hydrocarbons	<10 m for ground survey		305 × 169 × 161 mm; 4.3 lbs	Rechargeable Li-ion battery	

Flame Ionization Detector	Concentration	Point		Hydrocarbons	<1 cm			NiMH rechargeable pack	
Tunable Diode Laser	Concentration	Point or Open path	1 Hz	Methane					
High Flow Dilution Sampler	Emission rate	Component		Hydrocarbons or Methane	<1 cm	0.05 to 8.00 SCFM; ±10%	18L x 12W x 7H inches; 20 lbs		Class 1, Division 1
Catalytic Combustion									
Metal Oxide									
Gas Chromatography									
Mass spectrometry									
Printed Nanotubes									
Tunable Laser (Closed Path)									
Etalon									
Optical Gas Imaging									

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FTIR									

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5 EVALUATION OF METHODOLOGIES

5.1 Introduction

The evaluation of innovative methane detection systems is a rapidly evolving field that has been the subject of several recent publications and projects. This chapter summarizes the state of knowledge and discusses a basic framework for designing an evaluation protocol. Although it is beyond the scope of this document to provide a detailed protocol for evaluating the full diversity of technologies and applications, adhering to these principles when designing a protocol will help assure that systems are satisfactorily assessed for their ability to meet stakeholder goals.

5.2 State of the Knowledge

[NOTE: It may be more effective to discuss the case studies within the most relevant section rather than an initial state of knowledge section.]

Links to case studies:

- Monte Carlo Simulation Evaluation of Gas Imaging Technology
- Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator
- Methane Detectors Challenge
- ARPA-E METEC

5.2.1 Summary of Evaluation Process

The first step of developing an evaluation protocol is to define the stakeholders' goals for the innovative methane detection system. These goals should be specific and defined by quantitative metrics related to the performance of the system.

After defining the system goals, the second step is to determine which primary data performance criteria are necessary for meeting the goals. Depending on the complexity of the goal, this step may require advanced analytics such a Monte Carlo simulations or inverse Gaussian dispersion modeling. For example, a goal of detecting emission sources above a defined flux rate can use dispersion modeling to determine the precision of methane concentration measurements under specific meteorological conditions required to meet the detect the target emission rate.

The next step of an evaluation process is to test primary data performance criteria of leak detection systems. This can include investigating existing sensors with published performance criteria to determine which technologies can provide primary data adequate for meeting the goal. If there is insufficient data that technologies meet the required performance criteria, then the evaluation may require testing under controlled conditions such as a laboratory or test site. It is critical to complete this step before additional testing since the final goals cannot be met if systems do not meet the underlying primary data performance criteria.

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The final step of the evaluation process is to assess the performance of leak detection system goals under field conditions. For goals such as detecting a specific concentration or emission rate, an outdoor test site can use controlled releases to test performance under a range of meteorological conditions. More complex goals such as achieving equivalent emission reduction may require a combination of field testing, modeling, and side-by-site comparisons.

5.2.2 Selecting System Goals

There are several questions that stakeholders should answer when selecting the goals of a leak detection system. The list below is not exhaustive but provides a starting point for stakeholders.

5.2.2.1 What is the system trying to achieve or prevent?

- Detect concentrations above a specific limit at the fence line
- Detect the presence of emission sources above a specific rate
- Quantify the emission rate of individual sources
- Locate fugitive emission sources
- Assure site-level emissions are below an annual limit
- Assure site-level emission reductions achieve a percentage target
- Assure site-level emission reductions equivalent to another technology
- Assure population-level emission reductions equivalent to another technology
- Achieve compliance with a specific regulation or voluntary program

5.2.2.2 Which types of sites will use the system?

- New, multi-well production sites
- Well pads of any size or age
- Gathering compressor stations
- Processing plants
- A field of upstream and midstream oil and gas sites

5.2.2.3 Where will the system be used?

- Minimum and maximum temperature

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- Typical wind speed and direction
- Topography
- Vegetation structure (e.g., forested or grassland)
- Other methane sources in area

5.2.2.4 Who will maintain and/or receive data from the system?

- Frequency of visits
- Power requirements
- Data transmission requirements
- Tolerance of false positives

5.2.2.5 Does the system need to be specific to methane and/or measure other compounds?

- Methane only
- Total hydrocarbons
- Methane and VOCs

5.2.3 System Goals

After addressing these questions, stakeholders should define a list of goals for the system. The first goal should be specific to the primary outcome, such as:

- The system will send an alarm signal when fence line methane concentrations exceed 10 ppm CH4.
- The system will detect on-site, fugitive emission sources ≥ 6 scfh CH4 with an average response time of less than 7 days.
- The system will reduce annual fugitive emissions by 80% at the site-level as part of a leak detection and repair program requiring the repair of all leaks within 14 days of detection.
- The system will achieve equivalent emission reductions as semi-annual optical gas imaging surveys performed under the New Source Performance Standard OOOOa. Equivalency is defined as equal or greater annual avoided emissions from all of an operator's well pads in a basin.

Additional goals should include under what conditions the system must be able to function and performance metrics such as maintenance frequency and false alarm rate.

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Examples of system goals include the Methane Detectors Challenge (http://www.edf.org/sites/default/files/mdc_rfp_final.pdf, page 12) and ARPA-E MONITOR (https://arpa-.energy.gov/sites/default/files/documents/files/MONITOR_ProgramOverview.pdf). Goals should only include performance criteria that directly related to the desired outcomes. For example, if the purpose of a system is to detect emission sources above a specific rate, then the goal should not include an arbitrary concentration detection limit. As discussed in the next section, the underlying primary data requirements to meet the primary goal are determined analytically.

5.3 Determining Primary Data Performance Criteria

[TO BE COMPLETED]

- Converting an emission rate metric to a concentration metric using dispersion modeling (Lyon dissertation chapter; other references?)
- Converting an emission reduction metric to an emission rate detection limit and frequency with Monte Carlo simulations (FEAST model)
- Converting an equivalency metric to an emission rate detection limit and frequency with Monte Carlo simulations (OGI Monte Carlo, Kairos white paper?)

5.4 Equivalency Determination

NOTE: This section may be replaced with the Kairos white paper.

Regulations sometimes mandate the use of a specific technology for environmental compliance. In order to promote innovation, these regulations may include a process for permitting the use of alternative technologies. Typically, operators or technology developers are required to submit data that prove the alternative technology is equivalent or better than the default technology at achieving target metrics such as detecting leaks of a certain emission rate or reducing site-level emissions. Equivalency determinations can be classified into two basic categories: 1) equivalent assessment of individual emission sources, and 2) equivalent reduction of aggregate emissions.

For the first category, an alternative technology must demonstrate equivalent detection, quantification, or localization of individual emission sources of a similar type, emission rate, and gas composition. An example of this type of equivalency is the EPA New Source Performance Standard OOOOa definition of OGI (40 CFR §60.5397a(c)(7)(i)(B)), which specifies that OGI equipment "must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice". This determination is an assessment of a technology's ability to detect emissions from a well-defined source that can be evaluated with a controlled release under laboratory or field conditions.

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For the second category, an alternative technology must demonstrate equivalent emission reductions at a specific spatiotemporal scale such as a site's annual emissions. This is a much more complex determination because a technology's minimum detection limit and response time affect its ability to reduce emissions. Since many sites have highly skewed emission rate distributions, a technology that quickly detects large emission sources may lead to more reductions than a technology that slowly detects all emission sources. An example of this approach is Epperson et al. (2007), which used a Monte Carlo approach to simulate component emissions at a processing plant and assessed resulting emission reductions from the Method 21 and OGI. The model demonstrated that OGI resulted in equivalent or better site-level emission reductions due to its ability to more quickly detect large emitters than the current work practice of Method 21. In response, EPA revised their regulations to allow use of OGI as an alternative work practice to Method 21.

EPA NSPS OOOOa requires OGI to be used for leak detection and repair at oil and gas well pads (semi-annually) and compressor stations (quarterly). The rule includes a provision for other technologies to be used as an alternative means of emissions limitation (AMEL) if they achieve at least equivalent emission reductions of GHG and VOC emissions as OGI. The AMEL application process is outlined in 40 CFR §60.5398a with several submission requirements including a description of the technology and procedure and 12 months of data demonstrating equivalent reductions at the affected facility. Currently, the regulatory language includes ambiguity and EPA has not yet provided guidance on the specific data or procedures necessary for a successful application. Outstanding questions include the definition of an affected facility and the use of modeling versus empirical data.

Several studies have demonstrated that O&G sites have highly skewed emission rate distributions with the top 5% of sites responsible for about 50% of total emissions. These high emission sites, sometimes known as superemitters, may have malfunctions or abnormal process conditions that can be mitigated to reduce emissions. The occurrence of superemitters is primarily stochastic and therefore frequent monitoring is needed to identify these sites. Due to the skewed distribution rate, an application that quickly detects high emitters can achieve greater emission reductions at the population level than an application with a lower detection limit and slower response time. However, at the individual site level, a high emission screening approach will result in lower emission reductions at the majority of sites with relatively low emissions, but much greater reductions at high emission sites. Therefore, the demonstration of equivalent reductions is complicated by the variability in site emission rates if "affected facility" must be interpreted as a single site such as a well pad. Alternatively, an affected facility could be defined as an aggregation of individual sites such as all of an operator's well pads in a basin. Another approach could be to define an affected facility as a probabilistic model site, which uses the emission rate distribution of a population sites to represent a single site with a probability distribution function of emission rates. This approach would allow emission reductions to be calculated as probability function with a successful determination of equivalency based on a metric such as a ≥95% probability of equal or greater emission reductions than the reference approach.

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The efficacy of many applications for leak detection, quantification, and localization is impacted by meteorological conditions and site configurations. This includes the emission reduction potential of OGI, which physics-based modeling has shown to be dependent on parameters such as view distance and emissivity, some of which are not defined in OOOOa leak detection protocols. The immense diversity of conditions under which an application can be implemented precludes an empirical evaluation of all possible scenarios. Computer-based modeling, coupled with empirical validation of model accuracy, is a potential solution to rigorously evaluate application efficacy under the most likely encountered meteorological and site conditions. There are several recent examples of modeling used to evaluate sensor performance. A Gaussian dispersion model used 10 years of local, hourly meteorological data to predict the median hours to detection of potential emission sources at three model sites with different layouts of point and open-path methane analyzers. The FEAST model is a virtual gas field simulator that predicts emission reductions of various leak detection and repair programs. An effective demonstration of equivalency could include an empirical evaluation of an application at a structurally complex site such as a gathering compressor station over a time period such as 12 months that assesses performance under a wide range of meteorological conditions. If a computer model can accurately predict the detection limit and response time for different sources as a function of environmental parameters, then a probabilistic model can be used to simulate the performance at other sites. This approach could allow a scientifically rigorous determination of equivalency while minimizing the number of sites required for field testing.

5.5 Assessing Primary Data Performance Criteria

[To be completed]

Summarize Methane Detectors Challenge

Other citations about basic sensors testing such as precision and temperature tolerance?

5.6 Final Evaluation

[To be completed]

Summarize ARPA METEC protocols

Discuss side by side comparisons

Discuss modeling such as FEAST for assessing performance under untested conditions

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6 LESSONS LEARNED [PENDING]

This section discusses applicable stakeholder concerns, points of view, and interaction with the remediation process or other issue discussed.

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7 STAKEHOLDER PERSPECTIVES

The term "stakeholder" as defined in this document may be members of environmental organizations, community advocacy groups, Tribal entities or other citizens' groups that deal with environmental issues, or a concerned citizen who is not a member of any organization or group. Public stakeholders, such as advocacy groups, often speak for the communities that are affected by environmental issues.

Environmental regulators and other parties benefit from informed, constructive stakeholder involvement because it can help them to make better decisions, reduce the likelihood of costly, time-consuming repeated work, and allow those in affected communities to properly govern the long-term use of land, water, and other resources. This section addresses the concerns of stakeholders who may be asked to participate, or comment on evaluation methodologies or specific technologies with regards to methane detection.

7.1 Stakeholder Concerns

Many public stakeholders view climate change as an existential challenge that we, as a society, must confront head on. Because methane is a potent greenhouse gas that contributes to climate change, it is likely that stakeholders will, in general, support programs and regulations that increase the use of and improve detection of methane releases. It is often important to explain how methane contributes to environmental degradation (e.g., climate change) and safety in a reasonable, scientific way, and what can be done to reduce its impacts

As was stated in Section 1. Introduction [add link here], we recognize that there are limitations to the areas addressed in this document. The purpose of this document is to provide an overview of existing and developing technologies as well as guidance regarding performance characteristics and parameters to consider in technology evaluation. However, it does not seek to serve as an exhaustive, all-inclusive reference for methane emissions in all sectors, in all states, from all sources.

Stakeholders will, in general, support programs and regulations that increase the use of and improve detection of methane releases. It is often important to explain how methane contributes to environmental degradation (e.g., climate change) and safety in a reasonable, scientific way. There will likely still be concerns expressed if regulations or programs are limited to oil and gas production and distribution, thus requiring only a few sectors be evaluated for technology improvements.

Accordingly, representatives of interested parties who are coordinating discussions of evaluation methodologies or specific technologies with regards to methane detection will need to be aware that stakeholders may also have the following specific concerns.

7.1.1 The Contribution of Hydro-Fracturing to Methane Releases

Specific questions include does fracturing increase the amount of methane released from the subsurface; are there detection technologies for produced water; are there technologies used to detect leaks while injecting spent-fluids underground; does the evaluation program include areas subject to increase earthquakes (i.e., Oklahoma and Ohio) that could damage well completion at

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active or abandoned sites? There are several recent papers asserting that methane releases from hydro-fracturing account for 7% of production at these sites. (Horwith, McKibben, Harvard). Other studies refute this (cite here). However, it is important to point out that a program involving methane detection will raise these issues with stakeholders.

7.1.2 Offshore Wells

While it is understood by the stakeholders on this team that offshore drilling and production are outside of the scope of this document, some stakeholders may be concerned that this is overlooked, especially in coastal states. It is important to answer questions about why offshore production is excluded and if, nevertheless, some of the detection technologies can be used in an offshore setting. As noted in the Introduction, "Although off-shore emissions are of equal concern, these facilities are difficult to access (e.g., production platforms) and may be located in marine or sub-marine environments (e.g., platform-to-shore pipelines), which will require a different approach to methane emission detection." It will also be important to explain who has regulatory authority for these wells. [Add a note about un-availability of data if not stated in Introduction and/or Characterization Section].

7.1.3 Oil Wells Without Infrastructure to Capture Natural Gas

One of the largest incentives for the industry to reduce emissions of methane into the atmosphere is that it is a waste of a resource. In these instances, methane is usually flared or released. In North Dakota it is estimated that 30 percent of the O&G wells use flaring because of the lack of infrastructure. (See http://news.nationalgeographic.com/news/energy/2014/05/140522-gas-flaring-costs-taxpayers-in-us-report-says/) When this condition occurs, producers have little economic incentive, except for safety issues, to reduce methane emissions.

7.1.4 Transport of Oil by Rail

When oil is transported by rail, a small amount of the product is entrained natural gas. As the product settles out in rail cars, dangerous amounts of methane rise to the top. Under certain conditions, this has led to explosions. One way for the railcars to prevent this is to vent the methane. Stakeholders are concerned that these emissions are not captured, and while a relatively small amount, these are not detected nor are counted in the total emission of methane to the atmosphere (*confirm this stmt.*)

7.1.5 Adaptation of Detection Technologies

While it is understood this document deals with oil and gas production and distribution, it may not be clear why some of the technology innovations that would be evaluated under a state program could not also be used or adapted for other types of large methane emitters, such as landfills and feedlots.

7.1.6 Abandoned Wells

Abandoned wells represent a large problem in terms of safety, land-use and release of methane. Stakeholders will be concerned if technologies do not detect methane leaks from abandoned

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wells. In Los Angeles, a City-owned well field near Playa Vista is currently the subject of investigation by a stakeholder group, represented by the Physicians for Social Responsibility (PSR). This is an active well field; however, it is old and there may be abandoned wells.[24] Also, a home in Colorado recently exploded with fatal consequences when a line off of an abandoned well leaked (add link http://www.hcn.org/articles/fatal-colorado-home-explosion-reignites-drilling-safety-debate?utm_source=wcn1&utm_medium=email).

7.1.7 Wells Near Occupied Buildings

Stakeholders are concerned that detection techniques be evaluated that take into account where new wells are being developed close to occupied buildings.

7.1.8 Pipeline Safety.

Stakeholders are especially concerned if the program includes technologies that are developed and evaluated that can be used to detect leaks from pipeline emissions. The 2010 pipeline accident in a residential neighborhood in San Bruno CA (see https://www.aga.org/federal-agency-reports-studies/national-transportation-safety-board-ntsb/ntsb-accident/ntsb-accident) resulted in the destruction of 38 homes and eight fatalities and the 2014 East Harlem gas explosion [insert link to Introduction section side box] resulted in the collapse of two apartment buildings, displacement of 100 families and the deaths of eight, have increased stakeholders concern about leaking distribution pipelines.

7.1.9 Underground Storage Facilities.

National attention was drawn to the large volume methane release from an underground storage system in Aliso Canyon in southern CA [insert link to Introduction section side box]. Stakeholders are concerned that any program includes evaluation of technologies that will act as early detectors for these types of facilities.

Identifying affected public and tribal stakeholders early in the planning process and including the key stakeholders in the planning and implementation of the regulatory planning process is vital to the success of environmental regulators decisions.

[24] PSR called Peter Strauss on May 26, 2017 seeking advice on proposals for setback requirements and detection of methane from active and abandoned wells in this area.

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8 REFERENCES

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Appendix A. CASE STUDIES SECTION

Multiple case studies are being included to provide research, studies or comparative analysis of actual methane detection technologies. These Case Studies were selected based on their relevance to the development of a comparison methodology for emissions detection technologies. Case studies offer data on the application, design, performance, and monitoring of the environmental technology or approach.

Case Studies List:

1. Mobile Laboratory Observations of Methane Emissions in the Barnett Shale Region
2. Toward a better understanding and quantification of methane emissions from shale gas development
3. OGI at Jonah Energy - FLIR
4. JPL Methane Sniffer – PowerPoint Presentation
5. Are Optical Gas Imaging Technologies Effective For Methane Leak Detection
6. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States
7. Mobile Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities
8. Reconciling Divergent Estimates of Oil and Gas Methane Emissions
9. Improving Methane Emission Estimates for Natural Gas Estimates for Natural Gas Distribution Companies
10. City of Forth Worth Natural Gas Air Quality Study
11. CONCAWE Report no. 2/17: An evaluation of an optical gas imaging systems for the quantification of fugitive hydrocarbon emissions
12. Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras
13. Greater focus needed on methane leakage from natural gas infrastructure
14. Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol, Environmental Science and Technology
15. Methane Emissions Technology Evaluation Center (METEC) - in collaboration with Advanced Research Projects Agency – Energy; Methane Observation Networks with Innovative Technology to Obtain Reductions (ARPA-E; MONITOR)
16. Southwestern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report
17. Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report
18. Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique
19. Aliso Canyon Natural Gas Leak
20. Methane emissions estimate from airborne measurements over a western United States natural gas field
21. Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator
22. Comparing Policies to Reduce Methane Emissions in the Natural Gas Sector
23. Monte Carlo Simulation Evaluation of Gas Imaging Technology

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Case Study – Generic Outline – Natasha Sihoto

Mobile Laboratory Observations of Methane Emissions in the Barnett Shale Region

Authors:
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Short Summary Table.

Industry Sector: Oil and Gas	**Objective**: map methane emission rates using Gaussian simulations
Technology Name (type/category): Instrumented vehicle equipped with TILDAS and Picarro CRDS	**Date**: March 9, 2015

1. Background

- *Problem Statement*

Need to understand how different measurement and mapping technologies compare for evaluating CH4 emissions/plumes. Comparative study using aircraft and land based systems with multiple groups

- *Location description* (sector, facility type, acres, volume, owners/responsible parties)

Barnett Shale region (processing plants, gathering stations, compressor stations, well pads, and roadside piping)

- *Site complexities* (different pollutants from only Methane/VOCs?) Include any

"Several oil and gas facilities with large reported methane emissions were visited during this campaign". Tall emission stacks will not be properly simulated. The presence of co-emitted species helps identify emission sources. For example, the study showed the presence of CO2 and the ratios of CH4/CO2 and C2H6/CH4 suggest a fugitive leak at a dry gas compressor station. Measurements identified sources that are purely biogenic. These include sources such as cattle rumination and stagnant water, where methane emissions are observed with no concomitant enhancement in ethane. There are several landfills in this region, but only one was measured.

- *Date of Study*

Spring and fall of 2013

2.0 Technology Utilized

- *Briefly describe*

Ground and aircraft-based methods including:

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"Three Aerodyne Tunable IR Laser Direct Absorption Spectroscopy (TILDAS)", "operated in parallel drawing from the near-atmospheric pressure portion of the inlet, prior to the pressure controller: a LiCor CO2 analyzer; and a Thermo Fischer NOx detector.", GPS. The NOAA van was equipped with a Picarro CRDS ambient air analyzer measuring CH4, CO2 and H2O.

- *Reasoning for Use*

Pilot/demonstration of Gaussian dispersion "to estimate both the source location and the emission magnitude" coupled with mobile ground-based atmospheric measurements around selected oil and gas facilities.

3.0 Assessment

- *Performance/ Interferences/ Limitations/ Improvement*

The majority of the facilities chosen for analysis are high-emitting and they should thus not be considered a representative sampling of all operations in the Barnett Shale. A gas processing plant with simulated emissions at 193 kg/h compares favorably to reported facility 2013 GHGRP emissions of 115 kg/h.

Limitations – Gaussian plume analysis requires some wind (no measurements when windspeed < 1m/s). Locating the source of measured ground-based emissions can be difficult in certain areas. In other areas, there is no question of the emission source due to replicate measurements, a lack of other possible sources, or visual identification of the facility when driving on a nearby public road.

- *Cost (if available and relevant)*

Not included for TILDAS or Picarro CRDS analyzers. The study did put a cost to the methane emissions. 19% of emitters have simulated methane emissions larger than 10 kg/h. For 2012 Texas gas prices of $2.66 per thousand cubic feet, 98% methane content in natural gas, and assuming a sustained emission, this corresponds only to $12 K in lost revenue per year. The largest simulated emission of 1,360 kg/h corresponds to over $1.2 million/year.

- *Technology maturity level* (at the time of the case study) (if available/specified and relevant) (was in R&D stage, available off the shelf, well tested, etc.?) Technology Readiness Level (TRL)

  Not included in this study.

- Alternatives?

Not provided

4.0 Lessons Learned - authors

"plume transect sampling and iterative forward dispersion simulations are useful tools for emissions investigation, allowing large areas to be covered in a short amount of time (here, nine

plumes per hour of measurement are successfully quantified) without the need for facility access."

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Case Study – Generic Outline – Natasha Sihoto

Toward a better understanding and quantification of methane emissions from shale gas development

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Environmental Sciences, University of Colorado, Boulder, CO 80309; and hDepartment of Meteorology, The Pennsylvania State University, University Park,
PA 16802

Short Summary Table.

Industry Sector: academia, government	Objective: evaluate the use of instrumented aircrafts for delineating regional methane fluxes i.e., use a 'top-down' approach for evaluating methane emissions
Technology Name (type/category): Instrumented aircraft equipped with a Picarro CRDS	Date: March 12, 2014

1. Background

- *Problem Statement*

"Inadequate accounting of greenhouse gas emissions hampers efforts to identify and pursue effective greenhouse gas reduction policies." "the inaccessible and transient nature of these [natural gas] leaks make them difficult to identify and quantify, particularly at a scale at which they are useful for bottom-up inventories or mitigation strategies (i.e., leak rates of individual components or activities)."

- *Location description* (sector, facility type, acres, volume, owners/responsible parties)

"Measurements were conducted between June 18, 2012 and June 21, 2012 over southwestern PA using Purdue's Airborne Laboratory for Atmospheric Research, a modified Beechcraft Duchess aircraft. This aircraft is equipped with a 50-Hz Best Air Turbulence probe, described by ref. 36, that measures wind vectors and pressure, a 50-Hz microbead thermistor that measures temperature, a 50-Hz global positioning system/inertial navigation system, and a 0.5-Hz high

precision Picarro CO2/CH4/H2O cavity ring down spectrometer (CRDS). The CRDS has ~0.05% (1 ppb) precision for methane determined during in-flight calibration, and comparable accuracy, using three NOAA Earth System Research Laboratory tanks with CH4 concentrations of 1.8030, 2.2222, and 2.5995 ppm. A programmable flask package (PFP) provided by NOAA for whole-air sampling was also installed on the aircraft. The PFP consists of 12 flasks that hold air pressurized to 2.7 atm in 0.7-L bottles. Flasks are analyzed for 55 species, including CH4, and hydrocarbons, by NOAA."

- *Site complexities* (different pollutants from only Methane/VOCs?) Include any characteristics that are important for understanding the site

Multiple sites characterized from the air (at least 10 well pads)

- *Date of Study*

June 18-21, 2012

2.0 Technology Utilized

- Briefly describe

"an aircraft-based approach that enables sampling of methane emissions between the regional and component level scales and can identify plumes from single well pads, groups of well pads, and larger regional scales, giving more information as to the specific CH4 emission sources. We implemented three types of flights over 2 days in June 2012: investigative (I), mass balance flux (MB), and regional flux (RF)."

- *Reasoning for Use*

Technology pilot for this application. Demonstration of 'top-down' data aggregation approach

3.0 Assessment

- *Performance/ Interferences/ Limitations/ Improvement*

Good overall performance, not suitable for high resolution sampling at particular sites, but provides 'big picture' mapping of emissions over larger area

- *Cost (if available and relevant)*

Not available

- *Technology maturity level* (at the time of the case study) (if available/specified and relevant) (was in R&D stage, available off the shelf, well tested, etc.?) Technology Readiness Level (TRL)

8

- Alternatives?

Not provided

4.0 Lessons Learned - authors

Aircraft monitoring is suitable for developing integrated maps of emissions "at scales relevant to bottom-up inventories and mitigation strategies and to estimate the emission rate for a region encompassing a large number of well pads"

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Case Study – Generic Outline – Arun Ghimire

OGI at Jonah Energy - FLIR (Application Note - 3 Pages)

1. Background

Methane, an extremely potent greenhouse gas, and other VOCs are often emitted during industrial operations in the oil and gas industry. Optical Gas Imaging (OGI) is a new technique being used in place of Toxic Vapor Analyzers (TVAs), the current EPA leak-detection standard. This case study examined the effectiveness of OGI at Jonah Energy in Sublette County, WY.

2.0 Technology Utilized

Methane and VOCs absorb certain wavelengths of infrared radiation. The FLIR GF320, the OGI camera used by Jonah Energy, uses infrared cameras to see methane and VOCs by searching for "shadows" that stick out from the background caused by the gases absorbing radiation. It works real-time, can scan wide swaths at a time, and is nine times faster than the EPA's Method 21 protocol (Forth Worth, TX).

3.0 Assessment

OGI's speed results in more frequent inspections, preventing greater leakage and allowing for significant reduction of methane and VOC emissions.

"Since 2010, Jonah has reduced fugitive emissions by 75 percent. It also reduced repair time from 705 hours to 106, cut labor costs from $58,369 to $7,500, and dropped its gas losses from $348,000 to $20,500. Emissions in tons went from 351 to 31." Jonah Energy saved over $5 million over 6 years.

4.0 Lessons Learned

Fast identification of leaks leads to quicker repairs, minimizing environmental detriment while cutting asset losses. It was found that the total savings exceeded the costs of monitoring and repair. Early and real-time detection also allows for safer operations, as OGI users can detect not only the existence but the size of a gas plume, allowing them to avoid areas with explosive or asphyxiating gases.

OGI is quickly gaining acceptance in both federal and state regulatory agencies.

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Case Study – Generic Outline – Sydney Marlborough

Are Optical Gas Imaging Technologies Effective For Methane Leak Detection?

Short Summary Table (?)

Industry Sector: Oil & Gas	Objective : Tune OGI Technology
Technology Name : Open Source Model	Date: 11/29/2016

1. Background

- The US EPA proposed regulations requiring the use of optical gas imaging (OGI) technologies to identify and repair leaks. EPA GHG emissions estimates may be higher than previously thought. Regional studies made from aircraft find emission rates that do not align with expected emissions rates. The most common OGI technology used in the Oil and gas industry for methane relies on infrared imaging. Many facilities employ OGI-based technology for leak detection, yet systematic scientific analysis of the performance is lacking.

- Published 11/29/2016

2.0 Technology Utilized

- The article focused on the development and testing of a predictive model to accurately simulate passive infrared imaging (FLIR GF320 series)
- Reasoning for Use
    - Address the effectiveness of IR leak detection.

3.0 Assessment

- Model is used to evaluate OGI technology by varying the parameters like temperature and wind conditions, imaging distance and detection criterion, and facility characteristics. The combined model results and experimental data provide recommendations and best practices for achieving methane detection accuracy.

4.0 Lessons Learned

- The model found that imaging distance is the most important parameter for effective leak detection. The resolution is inversely proportional to the square of the imaging distance that results in a progressive reduction in efficiency. Measuring against sky increase resolution due to a greater difference in temperature change. Warmer days increase resolution due to a more drastic difference between plum temperature and surrounding equipment. The minimum detection threshold can be up to 3-4 times lower for wet-gas compared to dry-gas compositions. Wet-gas contains hydrocarbons with lower minimum detection limit which may skew GHG emissions data.

REF: Ravikumar, A.; Wang, J.; Brandt, A. Are Optical Gas Imaging Technologies Effective for Methane Leak Detection? *Environ. Sci. Technol.* 2017,51,718-724.

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Case Study – Generic Outline – Garrett Kelly

Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States

Short Summary Table

Industry Sector: Partnership between academic/public/private	Objective: Quantify current methane emissions throughout the United States
Technology Name (type/category): High-flow sampling method; Down-wind Tracer-Ratio	Date: March 31, 2015

1. Background

- *Problem Statement:* Development in the shale gas industry has resulted in increased natural gas usage, which has lower CO_2 emissions, but greater CH_4 emissions. CH_4 emissions might actually be more harmful to the environment and have a greater impact on global warming/climate change.
- *Location description (sector, facility type, acres, volume, owners/responsible parties):* This research was conducted by a group of academic and public and private sector researchers. They conducted the research throughout the United States at metering and regulating facilities and underground pipelines. The sample locations consist of: metering and regulating facilities with inlet pressures between 100 and 300 psi, plastic mains, unprotected steel services, unprotected steel mains, cast iron mains, regulators > 200 psi, metering and regulation facilities > 300 psi, and regulators 100-300 psi, including Transmission-Distribution Transfer Stations.
- *Site complexities (different pollutants from only Methane/VOCs?)* Include any characteristics that are important for understanding the site: Tested all different kinds of sites
- *Date of Study:* March 31, 2015

2.0 Technology Utilized

- High-flow sampling method, measure the flow-rate of the leak and has a modified enclosure that completely captures the leaking gas. Uses catalytic oxidation and thermal conductivity hydrocarbon sensors to measure the methane concentration in the air stream. A thermal gas flow sensor measures the sample flow rate. A downwind tracer-ratio measurements were used for quality assurance and allowed for readings within the experimental uncertainty.

3.0 Assessment

- *Performance/ Interferences/ Limitations/ Improvement:* This study was a successful way to analyze the current state of methane emissions in the United States to influence legislation and evoke a response. It gave a good viewpoint of what technologies are successful in preventing leaks as it compares the entire country. Newer pipelines and systems in the western United States are more efficient and have less leaks than the older pipelines and systems in the east. Also, it updates the GRI/EPA study conducted in the 1990s. One improvement would be to conduct the testing on more sites and try to ensure that sites of companies that did not volunteer to be tested are getting tested. This would help to ensure that there is an accurate basis of leaks across the industry.

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- *Cost (if available and relevant):* There weren't any cost numbers associated with this case study
- *Technology maturity level (at the time of the case study) (if available/specified and relevant) (was in R&D stage, available off the shelf, well tested, etc.?) Technology Readiness Level (TRL) [DOE Directive]:* The technology has obviously been thoroughly used and could be used further to conduct more testing.
- Alternatives? n/a

4.0 Lessons Learned

- From this case study, we can see that there needs to be further quantification with leaks in systems and pipelines throughout the country. The means were slightly skewed due to a low number of test locations. Having governmental assistance in order to test all sites could also lead to more accurate results that give a better picture of the entire industry.

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Case Study – Generic Outline – Adam Miller

Mobile Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities

Author/s & Affiliation/s: Derek R. Johnson, April N. Covington, and Nigel N. Clark. Mechanical and Aerospace Engineering Department, Center for Alternative Fuels, Engines, and Emissions, West Virginia University

Date: July 7, 2015

Industry Sector: Natural Gas Midstream

Technology: Eagle II Methane Detector (6 gas sampling), FLIR GF 320 (OGI) and Microdilution high volume sampling (equipment assembled by research team)

1 Background

Problem Statement: Emission estimates based on AP-42 values may not be accurate because actual leak and loss methane emissions are greater than estimates.

Location:

Sector:	Nat. Gas Midstream
Facility Type:	Compressor Station (3 sites) and Storage Facilities (2 sites)
Acres:	
Volume:	
Owner/Responsible Party:	Single owner – unidentified
Description:	Barnett field in Texas

Site Complexities:

Other Pollutants:	Methane comprised approximately 94% of the natural gas at all sites.
Characteristics:	
Other:	

2.0 Technology Utilized

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Technology:	Usage Reason:	Effectiveness:
Eagle II (6 gas sampler) [handheld]	Measure localized concentrations of methane (survey). Used as a screening tool for the study.	Lower detection limit of methane was 5 ppm above background concentration. Effective for ground level use, and use on ladders only. Seemed to function adequately for the intended use of the research team.
FLIR GF-320 (OGI) [handheld]	Identify points of interest at elevated locations such as tank hatches or vents, and as a scanning device for the site. Also used to verify that the microdilution high volume sampling system adequately captured leaks.	Effective at identifying leaks over a wide area and at specific locations. Pairs well with sampling equipment to ensure adequate collection of gases from leaks.
Microdilution high volume sampling equipment assembled by research team (HVS) [cart-mounted]	Used to quantify methane emissions.	Sampling train consisted of multiple parts including sample probes, blowers and various sensors that quantified methane using mass flow rate along with methane analyzer to determine leak concentration. Effective for analytical purposes. Physical size of the equipment may be a limiting factor for practical application.

3.0 Assessment

Performance:	
Interferences/Limitations:	
Improvement:	
Cost:	Eagle II < HVS < OGI
Technology Maturity Level:	

Technology Readiness Level:	
Alternatives:	Other manufacturers of similar equipment

4.0 Lessons Learned

Author Conclusions:	The study was conducted as part of the Environmental Defense Fund's Barnette Coordinated Campaign where researchers completed leak and loss audits of methane emissions. In this study three natural gas compressor stations and two natural gas storage facilities all of common ownership were audited. The audit reviled that only 12% of emissions totals were the result of leaks. Methane slip from exhausts represented 44% of total emissions and the remainder is attributed to losses from pneumatic actuators, engine crank cases, compressor packing vents, wet seal vents, and slop tanks. Other observations included that a small number of the total leaks identified were responsible for approximately 50% of emissions from leaks. (Johnson et al. 2015)
Methane Team Conclusions:	Leaks of methane at natural gas compressor stations and storage facilities in this case are a relatively minor component of the total facility-wide emissions of methane. However, of the emissions resulting from leaking equipment identifying "large" leaks and making repairs in a timely fashion provides a substantial reduction (approximately 6%) in methane emissions from these sites. To accomplish this task, OGI seems to be the superior technology to use for detection. One point to consider is the sample size of facilities was fairly small. The results of this study relative to emissions totals may not be representative of the industry as a whole.

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Case Study – Generic Outline – Adam Miller

Reconciling Divergent Estimates of Oil and Gas Methane Emissions

Author/s & Affiliation/s: Daniel Zavala-Araiza, et al; Environmental Defense Fund, Austin TX 78701 and others.

Date: December 22, 2015

Industry Sector: Oil and Gas Facilities

Technology: Aircraft mounted measurement systems

1 Background

Problem Statement: Published estimates of methane emissions are not accurate which leads to conflicting claims about the climate implications of switching from coal or petroleum to natural gas.

Location:

Sector:	Oil and Gas Facilities
Facility Type:	Fly-over of various facilities in the Barnett field; Production facilities (~53%), compressor stations (~31%), processing plants (~13) and others.
Acres:	
Volume:	
Owner/Responsible Party:	Various
Description:	Barnett field in Texas

Site Complexities:

Other Pollutants:	
Characteristics:	
Other:	

2. Technology Utilized

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Technology:	Usage Reason:	Effectiveness:
Aircraft mounted sampling equipment	To examine Top-down approach for estimating methane emissions	Difficult to discern effectiveness. Seems appropriate for focus of study.

3 Assessment

Performance:	
Interferences/Limitations:	Resource requirements to operate aircraft mounted systems make the technology impractical for most applications.
Improvement:	
Cost:	
Technology Maturity Level:	
Technology Readiness Level:	
Alternatives:	

4 Lessons Learned

Author Conclusions:	Methane emissions are significantly higher than estimates based on public inventories. Barnett methane emissions are dominated at any one time by a small number of high emitters. It is estimated that 2% of facilities in the Barnett region are responsible for half of the emissions; and, 10% are responsible for 90% of emissions. The "high-emitters' are divided roughly equally among production sites, compressors, and processing plants. (Zavala-Araiza, et al. 2015)
Methane Team Conclusions:	The study was a statistical comparison between actual data and facility estimates reported to EPA using default emission factors. For the study, sample data from aircraft mounted analysis equipment was compared with estimates based on US EPA greenhouse gas inventory.

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	A small number of sources contribute the largest portion to total emissions. Because it is impossible to know which sources are "high-emitters" at any given point in time, there is a need to respond to detectable emissions quickly. Characteristics of effective detection equipment in this case include: **1) Capability** – the equipment must be able to detect elevated emissions at a given source location; **2) Availability** – since there is a large number of sources, and it is not known which locations will be "high-emitters" there is a need for equipment to be available to a large number field personnel. The more people have access to detection equipment, the more likely emissions will be found; **3) Reliability** – detection equipment will likely undergo many hours of use during a given year; **4) Cost-effective** – to go along with availability a key factor is affordability of devices. Equipment that is too expensive is cost prohibitive; **5) Application** – Any device selected to identify emissions must be used by operators in order to be effective; unused technology, no matter how sophisticated, does no good. **Other intangibles**: facility personnel are actually looking for malfunctioning equipment and not just giving lip-service to reduction of emissions.

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Case Study – Generic Outline – Garrett Kelly

Improving Methane Emission Estimates for Natural Gas Estimates for Natural Gas Distribution Companies

Author/s & Affiliation/s:

Khalid Farrag, Gas Technology Institute

Kristine Wiley, Gas Technology Institute

Date: 11/2013

Industry Sector: Private

Technology: High-Flow Device

1. Background

Problem Statement: A field testing program was performed to: evaluate gas leak rates from belowground pipelines, provide a simplified procedure that can be used to monitor pipeline leaks from surface measurements, and update the methane emission estimates for the main lines in the distribution system.

Location: United States, 5 locations

Sector:	Private
Facility Type:	Utility Facilities
Acres:	N/A
Volume:	N/A
Owner/Responsible Party:	Distribution Operators/LDCs
Description:	These are gas distribution facilities across the United States where methane leakage is occurring

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Site Complexities: Varying types of pipelines and above or below ground

Other Pollutants:	N/A
Characteristics:	5 sites were tested with some being above and some being below ground. They were analyzed for the flow of leakage and how prominent the leak was.
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
High-Flow Device	Able to quantify and measure flow rates for leakage locations, understand current leakage levels nationwide	Rather effective, not a large variance from the correlation line

3.0 Assessment

Performance:	Overall, there was good performance from the sites tested
Interferences/Limitations:	Unable to completely capture all emissions due to scope, size, and accessibility
Improvement:	Able to completely capture emissions to give a true reading of leakage levels
Cost:	N/A
Technology Maturity Level:	This technology has been consistently used for a long period of time and is the standard in the industry for detecting and quantifying leaks
Technology Readiness Level:	8 or 9 as it is readily available to be used
Alternatives:	N/A

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4.0 Lessons Learned

Author Conclusions:	Technology has thoroughly advanced over the past 20 years and new methods are allowing for more accurate leakage readings. This study is narrow in scope, but accurate and able to prove that emission levels have decreased significantly.
Methane Team Conclusions:	This case study is very narrow in scope and would need to be conducted on more sites, locations, and leaks to ensure that leakage levels have decreased over the past 20 years. There is evidence here, however, that technology accuracy and usage has improved and will ultimately be able to help detect and quantify leaks.

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Case Study – Generic Outline – Craig O'Neill

City of Fort Worth Natural Gas Air Quality Study

Author/s & Affiliation/s: Eastern Research Group and Sage Environmental Consulting, LP
Optical Gas Imaging Versus U.S. EPA Method 21 by David Ranum of Sage Environmental Consulting, LP

Date: July 13, 2011

Industry Sector: Natural Gas Production and Processing Sites.

Technology: OGI: FLIR GasFindIR™ and FLIR GF320™ IR Cameras and Method 21: Thermo Scientific™ TVA-1000B Toxic Vapor Analyzer (TVA) plus Bacharach Hi Flow Sampler™ and Summa Passivated Stainless Steel Canisters from TestAmerica™

1. Background

Problem Statement: The Fort Worth Study was a study to review air quality issues associated with natural gas exploration and production. The study was performed with both Method 21 and the Alternative Work Practice (AWP) of Method 21 allowing Optical Gas Imaging in lieu of TVA's with the exception that the TVA must be used once per year. With this current limited use of OGI in place of Method 21, there are some states that are considering the use of OGI solely as their Uniform Standard (i.e. Colorado) and in place of Method 21. There is also a summary White Paper on this study from David Ranum of Sage Environmental Consulting, LP that was presented at InfraMation in 2015 titled: Optical Gas Imaging Versus U.S. EPA Method 21.

Location:

Sector:	Natural Gas Midstream, Production and Processing Sites in Fort Worth, TX
Facility Type:	375 Natural Gas Well Pads, 8 Compressor Stations, a gas processing plant and a saltwater treatment facility
Acres:	
Volume:	**Table 3.5-2. Average Point Source Emission Volumes by Site Type as measured by a HiFlow Sampler**

Site Type	TOC (cubic feet/yr)

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	Well Pad	148,552
	Well Pad with Compressor(s)	218,035
	Compressor Station	188,236
	Processing Facility	372,019
	Saltwater Treatment Facility	526
Owner/Responsible Party:	388 Sites owners in Fort Worth: Burnett Oil Production 2 Chesapeake Operating Inc. Crosstex Crow Creek Operating Inc Devon Energy Production Co Eagle Oil and Gas Encana Oil & Gas (USA) Inc Finley Frost Brothers Grand Operating Inc Lakota Energy LTD Newark Energy Proven Resources Quicksilver Resources Range Production Co Vargus Energy LTD Williams Production XTO Energy Inc	
Description:	well pads, compressor stations, processing facilities, a salt water treatment facility, drilling operations, fracking operations, and	

	completion operations.

Site Complexities:

Other Pollutants:	There were numerous other pollutants that are monitored under Method 21 as this study was on the technologies associated with Method 21.
Characteristics:	Methane was the primary air pollutant emitted at all sites which constitutes over 94% of the TOC (Total Organic Compound) estimate for all sites combined. Some Key Pollutants other than Methane in the study: Acetaldehyde Benzene 1,3-Butadiene Carbon tetrachloride *p*-Dichlorobenzene Formaldehyde Tetrachloroethylene
Other:	Methane had the highest concentrations of the study analytes.

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Optical Gas Imaging (FLIR GF320™ and GasFindIR™	OGI is the Alternative Work Practice for Method 21	OGI is more efficient at component leak detection and can inspect more component at a faster rate of approximately 9 times (OGI surveyed 100% of the equipment while Method 21 surveyed only 11% in the same time.
Thermo Scientific™ TVA-	The TVA is the current	Method 21 inspections were

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1000B Toxic Vapor Analyzer (TVA)	approved device for Method 21.	more effective at finding all leaks including the low leak definitions of the current regulations.
Bacharach Hi Flow Sampler™	Hi Flow Sampler testing was conducted at all emission points identified with the IR Camera (high level emissions) as well as at each emission point identified through Method 21 screening with a concentration >500 ppmv (low level emissions).	The Hi Flow Sampler was effective in quantifying the leaks found by both the OGI and Method 21 technologies.

3.0 Assessment

Performance:	The number of leaks detected by Method 21 but not detected by OGI represents 38% of the total leaks (797/2,094) but only 8% of the total emissions (100% - 92%).
Interferences/Limitations:	The OGI Camera has some limitations in detecting the leaks of the extremely small leaks but was very successful in finding most of the leaks very efficiently at a rate of 9 times faster. The TVA was more successful in detecting smaller leaks but is much more time consuming in utilization.
Improvement:	
Cost:	The TVA is more cost sensitive than the OGI Cameras.
Technology Maturity Level:	OGI Cameras have only been in the industry for 12 years and have a higher maturity potential than the TVA units that have been used for many years for Method 21 compliance. One of the limitations in OGI cameras is quantification and manufacturers are exploring solutions for this need.
Technology Readiness Level:	Both technologies are readily available and commonly used in the industry.
Alternatives:	The alternative to the FLIR GF320 OGI Camera is the Opgal

	EyeCGas and the FLIR GFx320.

4.0 Lessons Learned

Author Conclusions:	The Fort Worth Study was a very comprehensive Air Pollution Study with much data secured. In the study, Methane was the primary air pollutant emitted at all sites which constitutes over 94% of the TOC (Total Organic Compound) estimate for all sites combined. The referenced White Paper from the surveying company (Sage Environmental) is a great Summary of the Report with more details relating to the various technologies used in the study by comparing OGI to Method 21.
Methane Team Conclusions:	The City of Fort Worth Natural Gas Air Quality Study is a very comprehensive study with an abundance of information. It does not compare technologies very well but the White Paper from the company that performed the survey is a great tool to help compare the technologies used in the Fort Worth Study.

Other Resources

Optical Gas Imaging Versus U.S. EPA Method 21 by David Ranum, Sage Environmental Consulting, L.P. – From InfraMation 2015

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Case Study – Generic Outline – Craig O'Neill

CONCAWE Report no. 2/17: An evaluation of an optical gas imaging systems for the quantification of fugitive hydrocarbon emissions

Author/s & Affiliation/s: Concawe Air Quality OGI Ad-Hoc Group (Optical Gas Imaging):

C. Caico, L. Fragu, L. Gonzalez, C. Juéry, P. Kangas, C. Lawson, J. Negroni, P. Roberts, B. Smithers, P. Tupper, K. Vaskinen

Date: January 2017

Industry Sector: Oil and Gas

Technology: Thermo Scientific Toxic Vapor Analyzer (TVA 1000B) and FLIR GF320 with 38mm lens used with the Providence Photonics QL100

1. Background

Problem Statement: Test the performance of a quantitative optical gas imaging (QOGI) system to measure the mass emission rate of hydrocarbon leaks from industrial process equipment. For comparison purposes a conventional sniffing technique was also used for leak detection with emission estimates determined using the correlation equations from US EPA Method 21.

Location:

Sector:	Oil and Gas
Facility Type:	VITO's leak detection and repair facility in Mol, Belgium
Acres:	
Volume:	61 leak tests performed
Owner/Responsible Party:	Concawe
Description:	Leaking components were flange, valve, open-ended pipe

Site Complexities:

Other Pollutants:	Tested pollutant was a mixture of methane, propane, propylene (~33% each)
Characteristics:	Leak Rate was 1.7 – 1000 g/h

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Other:	Camera distance was 2, 3, 5 and 10 meters from the source

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Optical Gas Imaging	Allows leaks of hydrocarbon to be visualized.	Very effective as a visual tool but limited to detection only and not quantification
QL100 – QOGI Module	To work with the OGI Camera and calculate the hydrocarbon emission rate.	The QOGI system has been shown to be able to provide accurate quantification for individual leaks over the range 1.7 to 1000 g/h. Even where estimation is made for the total emissions from a number of leak sources (for example as would occur in an LDAR survey), the QOGI system provided a more accurate total flux value than M21. This suggests that QOGI could indeed be used for numerous applications in the O&G industry, including demonstration of LDAR compliance. These results were achieved when using a ΔT of 5 °C.
Method 21 approved sniffer	To estimate the emission of the leaking components as approved by Method 21.	The M21 correlations cannot be used to accurately estimate individual leak rates because of the statistical method used in their development.

3.0 Assessment

Performance:	Where leak rate quantification was achieved with the QOGI system the differences between the values determined and the known release rates were within a range of -23% to 69%, with

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	an average difference of 6%. By comparison, where the US EPA Method 21 correlations were used to estimate leak rates these differed from the known release rates within a range of -92% to 667%, with an average difference of 31%.
Interferences/Limitations:	The OGI camera requires a temperature difference, ΔT, between the gas and the background than for detection. From these tests, it was found that the current technology required a ΔT > 5 °C in order to successfully quantify emissions.
Improvement:	
Cost:	The TVA is more cost sensitive than the OGI Cameras.
Technology Maturity Level:	The QOGI quantification module is at a low maturity level and new to the market.
Technology Readiness Level:	Providence Photonics has a second generation QOGI module now with updated accuracies and features called the QL320.
Alternatives:	QL320

4.0 Lessons Learned

Author Conclusions:	This study was unique in a developing technology (QOGI) and comparing this to the proven Method 21 quantification technology (TVA). The results quite favor the newer technology but this study was performed in a controlled environment and not in field conditions.
Methane Team Conclusions:	

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Generic Outline Case Study – James Jarrett

Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras

Author/s & Affiliation/s: Carbon Limits AS for Clean Air Task Force

Date: March 2014

Industry Sector: Oil Production and Natural Gas

Technology: Optical Gas Imaging Camera (make/model not specified)

1. Background

Problem Statement: This case study used data from two (2) LDAR contractors using infrared cameras to detect sources of natural gas leaks and venting at well sites, compressor stations and gas plants. Ninety (90) percent of the monitoring was done in Canada at established facilities already doing LDAR monitoring. The remaining monitoring was performed in the United States. The monitoring results were then used to determine the economic merits of a LDAR program using IR cameras.

Location: Canada and United States

Sector:	Oil and Gas Sector
Facility Type:	Compressor Stations, Gas Plants and Well Sites / Batteries.
Acres:	
Volume:	1,915 compressor stations, 614 gas plants and 1,764 well sites/well batteries
Owner/Responsible Party:	Anonymous facilities LDAR contractors: Target Emission Services & Greenpath Energy
Description:	Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras

Site Complexities:

Other Pollutants:	Methane and VOCs
Characteristics:	This study used assumed gas compositions. For example: sweet gas contains 79% methane with 7.5% VOCs and sour gas contains 71%

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	methane with 3.6% VOCs.
Other:	Facility specific information such as age, size, operating mode, etc. was not available for this study.

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
IR camera	Detecting Leaks & Venting of Natural Gas	No comparison made with M21

3.0 Assessment

Performance:	Gas plants have the highest leak rate. Thirty-six (36) percent of well sites and batteries surveyed have no leaks at all. OGI inspection frequency effects the leak rates (monthly, quarterly, semi-annually, annually). More frequent OGI surveys results in lower leak rates, but higher costs.
Interferences/Limitations:	90% of data in this report is from Canada with established LDAR monitoring. It is not representative of US facilities. This study expects higher leak rates from US facilities, which would result in higher abatement costs.
Improvement:	Include a representative number of US facilities
Cost:	Assumes recovered gas costs $4/mcf. OGI contractor charges $600 to $1,800 per survey at well sites and over $5,000 per survey at a typical gas plant. Canadian gas plants are generally smaller than US gas plants. The highest abatement cost is $3,400/tVOC at compressor stations using monthly OGI surveys. The cost reduces to $700/tVOC using quarterly OGI surveys and -$200/tVOC using an annual OGI survey. The negative abatement cost means a net benefit for facility owners.
Technology Maturity Level:	Not included in this study.
Technology Readiness Level:	Not included in this study.
Alternatives:	This study stated alternative technologies in the future may reduce cost and improve effectiveness, but did not give any specifics.

4.0 Lessons Learned

Author Conclusions:	This study suggests that it is more economical to repair all leaks instead of picking and choosing which ones to repair, which makes is easier to implement and enforce. The study states oil and gas sector methane emissions are ~3 percent of the total US greenhouse gas emissions and ~30 percent of the methane emissions are from the oil and gas sector are from leaks. The leak rates in this study are not representative of US facilities since most the leak detection data is from Canada. Leak rates increased from 2 percent to 10 percent at Gas Plants by conducting monitoring annually instead of monthly. Gas Plants have the highest leak rate. Thirty-six (36) percent of well sites and batteries have no leaks at all. Compressor rod packing venting represents 21 percent of the total emissions observed at gas plants and 17 percent at compressor stations. The monitoring data in this study included 2,160 compressors with measured emission rates. The mean rod packing vent rate is 56.7 scfh. A large portion of the rod packing emissions originate from a relatively small fraction of compressors; 50 percent of the emissions is from 7 percent of the compressors emitting more than 200 scfh. Replacing rod packing has a small effect on the overall abatement cost of an LDAR survey program.
Methane Team Conclusions:	The reviewer agrees a "find it and fix it" approach for leaks is easier to implement and enforce. The study brings attention to venting that represents 70 percent of the methane emissions from the oil and gas sector, which is 70 percent of 3 percent of the total US GHG emissions. Venting is part of the normal design of equipment (e.g. level controllers, tanks, compressors, etc.). This suggests further study of capturing the vented gas and either recovering for gas sales or using it on-site for fuel is needed.

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Case Study – Generic Outline – John Collins

Greater focus needed on methane leakage from natural gas infrastructure

Authors:

Ramón A. Alvarez (Environmental Defense Fund), Stephen W. Pacala (Princeton University), James J. Winebrake (Rochester Institute of Technology), William L. Chameides (Duke University), and Steven P. Hamburg (Environmental Defense Fund)
Contributed by Stephen W. Pacala, February 13, 2012 (sent for review December 21, 2011)

1. Background-Problem Statement

Natural gas has the potential to lead to a shift away from other fossil fuels. The leakage rates in the natural gas supply network in the U.S., for this shift are studied in this paper and compared to other fossil fuels and the implications for reduction of greenhouse gas emissions (GHG).
An accounting for fuel cycle methane (CH4) leakage was considered on the climate impacts of fuel technology combinations. The concept of global warming potential (GWP), is defined as the amount of energy added to Earth's climate system by 1 kg of a gas relative to 1 kg of CO2. As the reference greenhouse gas, CO2 is given a GWP value of 1. This is used to compare the radiative forces of different gases to Carbon Dioxide (CO2) and represents the ratio of cumulative radiative forcing from emission of an equivalent quantity of CO2. The Intergovernmental Panel on Climate Change (IPCC) uses a 100 year time frame for the calculation, emphasizing the 20 year GWP, which emphasizes the early forcing years from early CH4 emissions.
One of the limitations for this approach is they only consider the radiative forces of single pulse emissions, which do not capture the climatic consequences of real world investment and policy decisions that are better simulated as emissions streams.

2. Technology Utilized

This was a study used several other studies data and developed their own data and to draw conclusions and recommendations.

3.0 Assessment

The paper uses EPA's current estimates of CH4 leakage from natural gas production and delivery infrastructure, in addition to a modest CH4 contribution from the vehicle itself (for which few empirical data are available). Compressed Natural Gas (CNG) fueled vehicles are not a viable mitigation strategy for climate change. Converting a fleet of gasoline cars to CNG increases radiative forcing for 80 years before any net climate benefits are achieved; the comparable cross-over point for heavy-duty diesel vehicles is nearly 300 years. Stated differently, converting a fleet of cars from gasoline to CNG would result in numerous decades of more rapid climate change because of greater radiative forcing in the early years after the conversion. This is eventually offset by a modest benefit. After 150 years, a CNG fleet would have produced about 10% less cumulative radiative forcing than a gasoline fleet; a benefit equivalent to a fuel economy improvement of 3 mpg in a 30 mpg fleet. CNG vehicles fare even less favorably in comparison to heavy-duty diesel vehicles.

In order to provide guidance to industry and policy makers the paper uses the maximum well to wheels. Or well to burner tip leakage rate to ensure the net climate benefits on all time frames after fuel switching to natural gas. The current estimated leakage rate is 4% for the entire natural gas supply. For a fuel switching scenario to be viable this leakage rate would need to be reduce by 45 % to 1.6%. At this rate CNG cars would provide an immediate climate benefit, and would improve over time. For heavy duty vehicles this rate would have to be reduced to less than 1%. For a switch from coal power plants to new natural gas plants the leakage rate must also be reduced to below 1%.

The analysis for reported routine emissions for over 250 well sites with no compressor engines in Barnett Shale, in 2010 revealed a highly skewed distribution of emissions. Leakage rates varied at well sites from 0 to 5%. Six sites out of 203 showed leak rates of 2.6% or greater in routine emissions.

4.0 Lessons Learned

A major assumption is that this entire comparison is based on these rates as a calculation as an average of the entire U.S natural gas supply. The paper emphasizes that much work needs to be done to determine actual emissions and accuracy to characterize the site to site variability in emissions.

Based on the conclusions, it does not appear that this switch is viable from a GWP reduction perspective, given the EPA estimated leakage rates, which have been under increasing discussion as underestimated.

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Generic Outline Case Study – Doug Burge

Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol, Environmental Science and Technology

Author/s & Affiliation/s: R. Subramanian; Center for Atmospheric Particle Studies and the Department of Mechanical Engineering, Carnegie Mellon University, Pittsburgh, Pennsylvania, et al.

Date: February 10, 2015

Industry Sector: Academic/Private Cooperative Study

Technology: On-Site Direct Measurement of Fugitive and Vented Sources combined with AP-42-based Exhaust Emissions Factors versus Downwind Tracer Flux (i.e., bottom-up versus top-down estimates)

1. Background

Problem Statement: Investigate uncertainty in site-level emission estimates, EPA Greenhouse Gas Inventory and EPA Greenhouse Gas Reporting Program using two independent estimates as a basis for emissions inventories.

Location:

Sector:	Transmission and Storage of Natural Gas
Facility Type:	Total of 45 Natural Gas Compressor Stations; 36 Transmission and 9 Underground Storage
Acres:	Various
Volume:	Various
Owner/Responsible Party:	Six Private Partner Companies
Description:	Selection of sites for study based on; geographic location, technology, partner company greenhouse survey team schedules, and suitability for tracer flux measurements. Study encompassed16 States in the South, Mid-Atlantic, Northeast, Midwest & Mountain West).

Site Complexities:

Other Pollutants:	Specific to natural gas system transmission and storage

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Characteristics:	Multiple natural gas sites included in study
Other:	Thermogenic (natural gas) methane and biogenic methane

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Down-Wind Tracer Flux	Quantify aggregate, site-level emissions of methane for large complex sites with multiple leak points	Adequate site-wide but does not identify specific sources driving emissions
On-Site Measurements	Comprehensive leak detection followed by direct measurement except for inaccessible sources and unburned methane in engine/turbine exhaust which were estimated	Adequate for low emitters but underestimated large emitters in study

3.0 Assessment

Performance:	Study identified a small number of sites contributing disproportionately to overall study emissions Sites with less than 200 standard cubic feet per minute flow (majority of sites in study) had reasonable agreement between the two measures of site-level emissions with tracer flux estimating somewhat higher emissions rates then on-site measurements Highest emitting sites (i.e., superemitters) had substantial underestimates of emissions by on-site direct measurement but were captured more fully by tracer flux.
Interferences/Limitations:	Highly skewed emissions dominated by

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Improvement:	Value of Greenhouse Gas Reporting Program could be improved by utilizing more direct measurements of emissions (versus using counts and emissions factors), avoiding use of acoustic devices, eliminating certain exclusions and using more appropriate emissions factors
Cost:	N/A
Technology Maturity Level:	Existing
Technology Readiness Level:	Existing
Alternatives:	N/A

4.0 Lessons Learned

Author Conclusions:	Highly skewed emissions dominated by a small number of sites which may not be captured by measurements have important implications for construction of reliable emission inventories
Methane Team Conclusions:	Study reinforces the fact that the use of appropriate and reliable sampling protocol in conjunction with identifying and appropriately quantifying "super emitters" are important components for the creation of accurate inventories of emissions.

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Case Study – Generic Outline – Doug Burge

Methane Emissions Technology Evaluation Center (METEC) - in collaboration with Advanced Research Projects Agency – Energy; Methane Observation Networks with Innovative Technology to Obtain Reductions (ARPA-E; MONITOR)

Author/s & Affiliation/s: Daniel Zimmerle, Colorado State University

Date: 10/1/2016 through 3/31/2019

Industry Sector: Government supported academic led technology assessment and development

Technology: Assessment of numerous technologies and applications at a target facility

1. Background

Numerous technologies are available for measurement of methane levels with different degrees of selectivity, sensitivity, accuracy and consequent cost to implement. The primary barrier to widespread utilization of continuous or semi-continuous methane measurement is cost. The goal of this program is to support development of approaches for detection and measurement of methane to enable and encourage widespread utilization to facilitate reductions in methane emissions.

Location: ***Fort Collins, Colorado***

Sector:	For evaluation at the well pad and further downstream. Initial focus on dry gas emissions, small production well pads and small equipment groups with future application to gathering and field compression sites, gas processing plants, compressor stations and local distribution stations.
Facility Type:	Model research test facility site consisting of model well pads
Acres:	Three test pads up to approximately 1,100 square feet in area
Volume:	Threshold leak size for technical performance targets detection is 6 standard cubic feet per hour (SCFH) (1 ton/year) with range of emission rates from 0-150 SCFH
Owner/Responsible Party:	Colorado State University
Description:	**Round 1**; Model production test pads with leakage possible for purposes of research and assessment from anywhere on the pads: Pad 1 – well head, horizontal separator and one 150 barrel above ground tank

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	Pad 2 – wellhead, horizontal separator and one 80 barrel above ground tank Pad 3 – three wellheads, two horizontal separators and two 300 barrel above ground tanks.

Site Complexities:

Other Pollutants:	Minimal non-specific pollutants unless otherwise introduced as part of assessment activities.
Characteristics:	Controlled research environment
Other:	Future planned development of METEC (Round 2) to include larger well pads, mock mid-stream compression facility and subsurface pipeline test bed for simulation of wet gas and mid-stream operations

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Various technologies to be employed	Research	In process

3.0 Assessment

Performance:	Non-specified initial testing has been conducted at the METEC facility start-up activities and provide data to improve measurement technologies
Interferences/Limitations:	Limitations from equipment available and testing configuration designs to be employed, future development will provide additional potential scenarios for testing

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Improvement:	On-going testing
Cost:	N/A
Technology Maturity Level:	N/A
Technology Readiness Level:	N/A
Alternatives:	N/A

4.0 Lessons Learned

Author Conclusions:	This is a test facility that has recently come on line and has the opportunity to produce significant data on testing equipment and methodologies. Still a work in progress.
Methane Team Conclusions:	As facility matures may be helpful to reach out to the METEC team to get more specifics on testing and technologies and results and availability

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Case Study – Generic Outline – Susan Stuver

***Southwestern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling* Report**

Author/s & Affiliation/s: PA DEP, Bureau of Air Quality

Date: November 1, 2010

Industry Sector: Government

Technology: Mobile Analytical Unit equipped with Gas Chromatography/Mass Spectrometry (GC/MS) and Open Path Fourier Transform Infrared (OP-FTIR) samplers, Canister Sampling, and FLIR Infrared Camera

1. Background

Problem Statement: With an increase in natural gas exploration activities in the Marcellus Shale, the Pennsylvania Department of Environmental Protection (PA DEP) set out to conduct short-term air sampling studies. This report focuses on operations in Southwestern counties including: Washington and Greene. The goals of the study were to collect ambient air concentrations for a specified list of contaminants, assess air quality impacts, health risks, and make conclusions on whether the short-term study necessitates an expanded scope.

Location: Southwestern Pennsylvania – Washington and Greene County

Sector:	Natural Gas
Facility Type:	2 natural gas compressor stations, 1 condensate tank farm, 1 wastewater impoundment, and 1 background site
Acres:	N/A
Volume:	N/A
Owner/Responsible Party:	Stewart Compressor Station near Hickory, PA (Washington County) Cross Creek Tank Farm near Rea, PA (Washington County) Energy Corp. Compressor Station near Khedive, PA (Greene County)

	Yeager Impoundment near Washington, PA (Washington County) Florence Commonwealth of Pennsylvania Air Monitoring Station (COPAMS) within Tillman State Park (Washington County)
Description:	Variety of natural gas facilities in Southwestern Pennsylvania, within the Marcellus Shale

Site Complexities:

Other Pollutants:	Main pollutants screened for include: methane, ethane, propane, butane, BTEX, methyl mercaptan, carbon monoxide, nitrogen dioxide, and ozone. The PA DEP created a list of target contaminants to screen for based on previous shale gas studies.
Characteristics:	N/A
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Agilent 6890/5975 MSD Gas Chromatograph/Mass Spectrometer (GC/MS) with a Dynatherm IACEM 980 Air Sampler	Could collect 0.5 L samples over 5-minute time period, once every hour	Allowed for the ambient air sampling required for this short-term report
RAM 2000 Open Path Fourier Transform Infrared Spectrometer, following U. S. Environmental Protection Agency's (EPA) Compendium Method TO-16	Detection of 48 volatile organic compounds (VOCs) over varying time periods	Captured data which allowed for understanding of common contaminants found in proximity to facilities and allowed for comparison to understand health hazards
Air canister samples using EPA Compendium Method TO-15	Sub part-per-billion detection of a large variety of contaminants	Effectively collected samples over 24-hour time periods
FLIR Model GF-320 infrared	Allowed for detection of leaks which could not be seen with	Effectively showed that the

camera	the naked eye	facilities sampled had leaks

3.0 Assessment

Performance:	The applied technology aided discussion and allowed for conclusions to be made for the study goals. The variety of technologies used allowed for data to be collected on a wide range of target contaminants over varying time periods. The results allowed for discussion on the most commonly seen contaminant (methane and benzene), comparison with reference concentrations when adverse health effects are observed, and air quality standards.
Interferences/Limitations:	Not stated
Improvement:	Not stated
Cost:	Not Stated
Technology Maturity Level:	Combination of many well-used technologies
Technology Readiness Level:	TRL 9: Commercially available
Alternatives:	Not stated

4.0 Lessons Learned

Author Conclusions:	This sampling campaign found concentrations of natural gas constituents and associated contaminants. Most of the contaminants detected were seen at the two compressor stations. Odorous contaminants (e.g. methyl mercaptan) were detected at levels where an odor would be expected. Based on the sampling performed it is not expected that air-related health issues would be seen. Also, no level of specified contaminants exceeds the National Ambient Air Quality Standard. FLIR camera work was successful at detecting certain pollutants which could not be seen with the naked eye. Although the facility specific level observed show no overall concern for health of air quality the cumulative effects over multiple facilities needs to be assessed.
Methane Team Conclusions:	

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Case Study – Generic Outline – Susan Stuver

Northeastern Pennsylvania Marcellus Shale Short-Term Ambient Air Sampling Report

Author/s & Affiliation/s: PA DEP, Bureau of Air Quality

Date: January 12, 2011

Industry Sector: Government

Technology: Mobile Analytical Unit equipped with Gas Chromatography/Mass Spectrometry (GC/MS) and Open Path Fourier Transform Infrared (OP-FTIR) samplers, Canister Sampling, and FLIR Infrared Camera

1. Background

Problem Statement: With an increase in natural gas exploration activities in the Marcellus Shale, the Pennsylvania Department of Environmental Protection (PA DEP) set out to conduct short-term air sampling studies. This report focuses on operations in Northeastern counties including: Susquehanna and Sullivan. The goals of the study were to collect ambient air concentrations for a specified list of contaminants, assess air quality impacts, health risks, and make conclusions on whether the short-term study necessitates an expanded scope.

Location: Northeaster Pennsylvania – Susquehanna and Sullivan County

Sector:	Natural Gas
Facility Type:	2 natural gas compressor stations, 1 completed and functioning well site, 1 well during fracturing operations, and 1 background site
Acres:	N/A
Volume:	N/A
Owner/Responsible Party:	Cabot's Lathrop Compressor Station near Springville, PA (Susquehanna County) Cabot's Teel site off near Springville, PA (Susquehanna County) Cabot's Gesford 2V and 7H well, Carter Road near Dimock, PA (Susquehanna County) Stone Energy's Loomis well site near Lawton, PA (Susquehanna

	County) Sones Pond parking lot in the Loyalsock State Forest (Sullivan County)
Description:	Variety of natural gas facilities in Northeastern Pennsylvania, within the Marcellus Shale

Site Complexities:

Other Pollutants:	Main pollutants screened for include: methane, ethane, propane, butane, BTEX, methyl mercaptan, carbon monoxide, nitrogen dioxide, and ozone. The PA DEP created a list of target contaminants to screen for based on previous shale gas studies.
Characteristics:	N/A
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Agilent 6890/5975 MSD Gas Chromatograph/Mass Spectrometer (GC/MS) with a Dynatherm IACEM 980 Air Sampler	Could collect 0.5 L samples over 5-minute time period, once every hour	Allowed for the ambient air sampling required for this short-term report
RAM 2000 Open Path Fourier Transform Infrared Spectrometer, following U. S. Environmental Protection Agency's (EPA) Compendium Method TO-16	Detection of 48 volatile organic compounds (VOCs) over varying time periods	Captured data which allowed for understanding of common contaminants found in proximity to facilities and allowed for comparison to understand health hazards
Air canister samples using EPA Compendium Method TO-15	Sub part-per-billion detection of a large variety of contaminants	Effectively collected samples over 24-hour time periods
FLIR Model GF-320 infrared	Allowed for detection of leaks which could not be seen with	Effectively showed that the

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camera	the naked eye Can be used from a distance to scan a large area then zoom allows for observation of components of interest	facilities sampled had leaks

3.0 Assessment

Performance:	The applied technology aided discussion and allowed for conclusions to be made for the study goals. The variety of technologies used allowed for data to be collected on a wide range of target contaminants over varying time periods. The results allowed for discussion on the most commonly seen contaminants, comparison with reference concentrations when adverse health effects are observed, and air quality standards.
Interferences/Limitations:	Not stated
Improvement:	Not stated
Cost:	Not Stated
Technology Maturity Level:	Combination of many well-used technologies
Technology Readiness Level:	TRL 9: Commercially available
Alternatives:	Not stated

4.0 Lessons Learned

Author Conclusions:	This sampling campaign found concentrations of natural gas constituents and associated contaminants. Contaminants were detected at the two compressor stations and the well sites. Odorous contaminants (e.g. methyl mercaptan) were detected at levels where an odor would be expected. Based on the sampling performed it is not expected that air-related health issues would be seen. Also, no level of specified contaminants exceeds the National Ambient Air Quality Standard. FLIR camera work was successful at detecting certain pollutants which could not be seen with the naked eye. Although the facility specific level observed

	show no overall concern for health of air quality the cumulative effects over multiple facilities needs to be assessed.
Methane Team Conclusions:	

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Case Study – Generic Outline – Steve Richardson

Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique

Author/s & Affiliation/s:

Chris W. Rella, Tracy R. Tsai, Connor G. Botkin, Eric R. Crosson, and David Steele

Picarro Inc.

Date: March 25, 2015

Industry Sector: Oil and Gas

Technology: Mobile Flux Plane Technique

1. Background

Problem Statement: Measuring fugitive methane emission rates from oil and natural gas well pads can be time-consuming, inefficient and cause underestimation of total methane emissions when individual component's emission rates are aggregated. The authors of this paper present a novel technique which allows for calculation of total well pad emissions which is rapid and efficient and does not require access to site infrastructure. The study was to assess the capabilities (both in a controlled experiment and field setting) of the technique and draw conclusions on emission rates in the Barnett shale, Texas.

Location: Barnett Shale, Texas (Counties: Cooke, Denton, Hood, Johnson, Montague, Parker, Tarrant, Wise, and Somervell)

Sector:	Oil and Natural Gas
Facility Type:	200 oil and gas well pads
Acres:	N/A
Volume:	207 sampling events performed

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Owner/Responsible Party:	Well pads sampled were in close proximity (<150 m) to public roads. No physical access to sites given.
Description:	Oil and gas well pads in nine counties within the Barnett shale

Site Complexities:

Other Pollutants:	N/A
Characteristics:	Sites needed to have public road access in proximity (<150 m) to the well pad. Site needed to be assessed using publicly available satellite imagery that an intercepted plume would contain emissions only form that well pad. Lateral wind speed needed to be greater than 1.0 m/s. Plume geometry needed to fall within the constraints of the sampling pole (4.2 m in height)
Other:	Only methane was sampled.

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Modified version of a commercially available near-infrared laser-based Cavity Ring-Down Spectrometer (CRDS), Model G2301, by Picarro	Real-time methane concentration analysis (2 Hz) Subparts-per-billion accuracy and precision	Effectively sampled methane concentrations for Mobile Flux Plane Technique
Sonic anemometer, Model 102779 by Climatronics	Not stated	Provided valued wind direction and speed data for the study
Submeter-resolution GPS unit, model R100 by Hemisphere	Real time location and vehicle speed	Provided required data
Sampling mast consisting of 1 monitoring port and 6 gas inlets evenly spaced over 4.2 m, connected to AirCores	Allowed for a planar sample to be collected in 5 minutes using one gas analyzer	Effectively provided a planar sample which could apply a limited Gaussian plume model to calculate the flux from a

capable of holding 50s of sampled air		well pad

3.0 Assessment

Performance:	With significant data interpretation to identify reliable well pad samples, the authors detected 115 emitting well pads and 67 non-emitting well pads from the total 207 samples taken. It was found that for the emitting wells the arithmetic mean was 1.72 kg/h (though highly skewed) and 95% emitted between 0.037 and 10.5 kg/h. Including the non-emitting well pads the arithmetic mean was found to be 1.1 kg/h. The authors stated that 50% of emissions is a result of 6.6% of the highest emitting wells, and 80% is a result of 22% if the highest emitting wells.
Interferences/Limitations:	Biases in the Barnett data set are a result of the authors only sampling wells with public road access within 150 m of the well pad. Plume geometry limits the use of collected data. If the sampling plane does not collect the extent of the plume in either the horizontal or vertical direction the data cannot be used. This is assessed by comparing the centroid of the plume to the size of the sampling mast. The collected data was not compared to other methods for methane emission determination. Therefore, the validity of the data set cannot be verified. However, a validation experiment showed measurement precision with a geometric standard deviation of 1.9, accuracy of 24%, and a detection limit of 0.034 kg/h. For measurements, greater than 3.6 times the detection limit the accuracy is found to be greater than 95%.

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Improvement:	N/A
Cost:	Not stated
Technology Maturity Level:	The application of this technique is the first study of its kind
Technology Readiness Level:	TRL 6: Technology Demonstration
Alternatives:	Disaggregated HiFlow sampling of well pad components Dual Tracer releases The reported technique is unique in that it does not require site access.

4.0 Lessons Learned

Author Conclusions:	This study was the first to apply the Mobile Flux Plane Technique. Based on the data collected, this technique can be used to assess a well pad's total methane emission rate. The finding that 80% of emissions are a result of 22% of wells suggests, if this finding can be verified, that this technique can be deployed rapidly to find highest emitting well pads. This would allow (with strategic management) for a large reduction of total emissions if highest emitters were targeted for corrective measures.
Methane Team Conclusions:	

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Case Study – Generic Outline – Steve Richardson

Aliso Canyon Natural Gas Leak

Author/s & Affiliation/s: California Air Resources Board (ARB)

Date: October 21, 2016

Industry Sector: Oil and Gas

Technology: Airborne flight measurements, inventory verification, tracer flux ratio study, and ground-based remote sensing

1. Background

Problem Statement: On October 23, 2015, a large natural gas leak was discovered at Southern California Gas' Aliso Canyon, storage facility. It was discovered that a breach in storage infrastructure below ground surface was discharging large volumes of methane to the atmosphere. The leak was controlled on February 11, 2016. The Governor of California issued a proclamation that Southern California Gas must fund a program to "fully mitigate the leak's emissions of methane." (See full report for reference) To do so, the amount of methane released to the atmosphere needed to be estimated, and the California ARB assessed methodologies to delineate the upper bound of the estimated methane release.

Location: Aliso Canyon natural gas storage facility in Los Angeles County, California

Sector:	Oil and Gas
Facility Type:	Natural gas storage facility
Acres:	N/A
Volume:	109,000 metric tons of methane
Owner/Responsible Party:	Southern California Gas (SoCalGas)
Description:	Natural gas storage facility where extraction occurs during November-March and injection occurs during April – October

Site Complexities:

Other Pollutants:	N/A
Characteristics:	Released methane exited the well with considerable upward velocity. Multiple leakage points created complexity in

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	measurement. Site has complex terrain and wind patterns. Evidence suggests that the methane plume became bi-modal, making it difficult to capture the entire plume for some measurement techniques. Road access downwind presented challenges for measurement techniques
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Airborne Measurements	Allowed for measurement within the plume, therefore the entire plume can be captured	Depending on the integration method used results can vary, using two different methods (not outlined in this case study) estimates were 94,500 MT and 97,100 MT
Inventory verification	Allows for the estimate of leakage through pressure measurements within the reservoir and using instrumentation already in place	Estimated leakage was 84,221 MT however with and uncertainty of 125%
Tracer flux ratio study	Well-practiced technique for estimating emissions from a point source	Technique yielded an estimate of 86,022 ± 8,393 MT. Underestimation is thought to be due to having a multi-point source, lack of mixing of the plume and tracer, the entire plume may not have been captured due to road access and a lack of measurements prior to December 21, 2015
Ground-Based Remote Sensing, ground-based spectrometer	Pre- and post-leak data available, continuous measurement frequency	Technique yielded an estimate of 100,050 ± 23,562 MT

3.0 Assessment

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Performance:	ARB assessed all the techniques used to estimate the total methane released. In order to develop the final estimate the ARB chose to use the airborne measurements and application of the Weymouth Equation which uses reservoir pressures and they broke up the leakage time period into two phases, Phase I: Initial Leak and Well Control Attempts and Phase II: Drawdown. Using this technique ARB stated the final amount of methane released was 99,650 ± 9,300 MT and used the upper bound of 109,000 MT.
Interferences/Limitations:	N/A
Improvement:	N/A
Cost:	Not stated
Technology Maturity Level:	Application of multiple mature techniques
Technology Readiness Level:	TRL 9: Commercially available
Alternatives:	Was selected as the best technique compared to multiple

4.0 Lessons Learned

Author Conclusions:	The authors concluded that using this application of airborne measurement coupled with the described analysis, was the most accurate estimate for total methane emissions. Using this technique, the total methane that needs to be mitigated to offset this leak is 109,000 MT.
Methane Team Conclusions:	

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Case Study – Generic Outline– Lisa Dorman

Methane emissions estimate from airborne measurements over a western United States natural gas field

Author/s & Affiliation/s: Anna Karion, Colm Sweeney, Gabrielle Petron, Gregory Frost, R. Michael Hardesty, Jonathan Kofler, Ben R. Miller, Tim Newberger, Sonja Wolter, Robert Banta, Alan Brewer, Ed Dlugokencky, Patricia Lang, Stephen A. Montzka, Russell Schnell, Pieter Tans, Michael Trainer, Robert Zamora, Stephen Conley

First Published: August 27, 2013

Industry Sector: Production

Technology: methane mass balancing using aircraft mounted measurements.

1. Background

Problem Statement: Lack of accurate and reliable emissions estimates from natural gas production. Many methane emission calculations are estimated "bottom up" using emission factors. The national average production-sector leak rate is an ever changing number as EPA revises assumptions for calculating emissions. Regional variations, more accurate emission factors and approaches are needed.

Location: Uintah County, Utah

Sector:	Production
Facility Type:	Oil and gas field: 4800 gas wells, nearly 1,000 oil wells
Acres:	593,053 Acres
Volume:	
Owner/Responsible Party:	Multiple – Uintah Basin, Uintah County
Description:	The current method of estimating emissions may be drastically underestimating. By taking measurements by aircraft from a concentrated production field, researchers asserted that inventory estimates are too low. The average leak rate determined of 8.9 +/- 2.7% is a factor of 1.8 greater than US Government Accountability Office (GAO) estimate. Additionally, the GAO included both flaring and venting. This study did not account for methane converted to CO2. Additional study is needed.

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Site Complexities:

Other Pollutants:	Not noted
Characteristics:	Uintah Basin/County well suited to measurement with aircraft because wells concentrated in a manageable area.
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Mass balance approach for deriving CH4 fluxes using measurement from aircraft	Current estimating scenarios not accurately depicting fugitive emissions	Aircraft mounted measurement showed inaccuracies within emission factors.

3.0 Assessment

Performance:	Good
Interferences/Limitations:	Measurements are a snapshot. Additional testing is necessary.
Improvement:	N/A
Cost:	Unknown
Technology Maturity Level:	N/A
Technology Readiness Level:	N/A
Alternatives:	N/A

4.0 Lessons Learned

Author Conclusions:	Leak rate during production is costly to both the bottom line and the environment and is not being accurately estimated at present. As stated by the authors of the paper, "Given the large global

	warming potential of CH_4, a natural gas leak rate of 6.2% - 11.7% during production negates any short-term (<70 years) climate benefit of natural gas …..for electricity generation compared to coal and oil.
Methane Team Conclusions:	There is a need across the industry for more accurate measurement of emissions.

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Case Study – Generic Outline – Sidney Marlborough [Sydney offered to redo using final version of "template" - with tables - and resend to us]

Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator

Authors:

Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt*

Department of Energy Resources Engineering, Stanford University, 367 Panama Street, Stanford, California 94305, United States

Short Summary Table (?)

Industry Sector: Oil & Gas	Objective : detection and repair performance
Technology Name : Open Source Model	Date: 03/23/2016

1. Background

- Fugitive methane (CH4) emissions from the natural gas system are an important source of anthropogenic greenhouse gases. Leak detection and repair (LDAR) programs aim to reduce fugitive CH4 emissions while providing additional revenue to natural gas producers from the sale of recovered gas. LDAR is an area of active research, and many proposed LDAR concepts rely heavily on new technologies, including constant monitoring of gas wells with high-precision methane sensors, automated surveys of natural gas fields based on infrared (IR) camera technology, or remote sensing of methane plumes using aircraft or satellites.
- Published 03/23/2016

2.0 Technology Utilized

- The article focused on the development developed of the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model to explore the effect of various LDAR programs on long-term leakage rates.
- FEAST is an open-source model programmed in the MATLAB computing environment

3.0 Assessment

- Markov model is implemented in three basic steps:
    - gas field initialization;
    - dynamic simulation; and
    - results storage
- A FEAST scenario is defined by the user-defined settings, inputs, and underlying data set provided to FEAST.

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- FEAST is stochastic, results will change each time it runs a particular scenario. Numerous realizations (scenarios) must be analyzed to understand the implications of a particular scenario.

4.0 Lessons Learned

- The economic analysis of various LDAR programs presented in the study is only indicative of general trends. It should be noted that extrinsic factors such as the leak production rate and gas price play an out-sized role in determining value various LDAR programs.
- Calculations are operator-centric
- The model may help in choosing a LDAR program that provides the best cost / benefit for a particular scenario compared to a field without an explicit LDAR program.

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Case Study – Generic Outline – James A. Jacobs

Evaluation of Policies for Monitoring, Repairing and Reporting Methane Emissions

Article Reviewed: Munnings, C., and Krupnick, A., 2017, **Comparing Policies to Reduce Methane Emissions in the Natural Gas Sector"**, Resources for the Future; 42 p.

Article Author/s & Affiliation/s: Clayton Munnings and Alan Krupnick, Resources for the Future (RFF)

Date of Article: July, 2017

Industry Sector: All Oil and Natural Gas Subsectors

Technology: Policy for evaluating the monitoring and reporting for methane gas emissions in the natural gas sector.

1. Background

Problem Statement: The authors of the policy article (Munnings and Krupnick, 2017) state that methane emissions from the natural gas sector threaten to reduce beneficial climate gains of gas over coal due to the unregulated methane emissions policies or the poor economic decisions of imposing one solution over all sites with methane leaks. The majority of existing sources of methane emissions in the natural gas sector remain unregulated. This is due in part to concerns that policies to mitigate these emissions would entail overseeing a large number of sources and impose significant administrative and compliance costs.

The authors point out nine findings which need to be addressed by updated methane emission monitoring, leak repair, and reporting. The most important finding is that super-emitters account for most of the methane: that the largest 5% of the leaks are responsible for 50% of the methane emissions from the natural gas sector and that 15% of the natural gas production sites contribute up to 80% of the leaked methane. US EPA's best management practices for leak detection and repair programs is a decade old, and new technologies (hand-held and drone/satellite optical instruments) are now available to identify large-scale methane leaks. The authors note the three main methane emission policies: leak detection and repair (LDAR), leak detection with optical imaging technology (LDRO), and leak detection with sampling (LDRS).

Location: U.S. Gulf Coast

Sector:	Upstream operations to downstream operations.
Facility Type:	Various operations - production, processing, transmission and storage, and distribution

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Acres:	N/A
Volume:	N/A
Owner/Responsible Party:	N/A
Description:	Technology and policy review for detection of methane emissions

Site Complexities: N/A

Other Pollutants:	N/A
Characteristics:	N/A
Other:	N/A

2. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
Leak detection and repair (LDAR)	The current standard	Limited: US EPA best practices guide (2007) is dated with notable concerns: not identifying all regulated components in inventory, not monitoring components properly, insufficient time to identify a leak, poor instrument calibration, and training issues.
Leak detection with optical imaging technology (LDRO)	Detect leaks with hand-held optical instruments	High monitoring costs due to labor over all sectors
Leak detection with sampling (LDRS).	Detect leaks and then sample air	High monitoring costs due to labor over all sectors
Leak detection with large-scale optical imaging technology (LDRL)	Detect leaks using optical instruments mounted to satellites, planes and aerial drones	Low monitoring costs; but only large-scale leaks could be detected

3.0 Assessment

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Performance:	
Interferences/Limitations:	Various data source make comparisons difficult
Improvement:	Using optical imaging methane detection equipment (hand-held) or by plane/satellite, large scale methane emissions can be detected and the leaks repaired.
Cost:	Currently, costs range from about $2/Mcf to $5/Mcf methane reduced, depending on the mitigation measures.
Technology Maturity Level:	Technologies to identify methane leaks are improving, but still relatively new.
Technology Readiness Level:	The technologies are currently available.
Alternatives:	Encouraging natural gas operators to detect and fix leaks, especially large leaks, requires tax and policy incentives. New policies need to be developed which will address methane super-emitters.

The figure below shows that marginal methane abatement costs, averaged within each subsector, range from less than $2 to more than $5 per thousand cubic feet (Mcf) of methane reduced, with the least expensive abatement in the upstream operations (production subsector) and most expensive abatement in the downstream operations (transmission and storage subsector). The summary is that upstream (well production) operations have lower emissions as well as limited distance of pipelines, pumps and valves, compared to larger-scale downstream operations.

National Aggregate Marginal Abatement Cost Curve for Oil and Natural Gas Subsectors from the U.S. Gulf Coast Region (ICF, 2016a)

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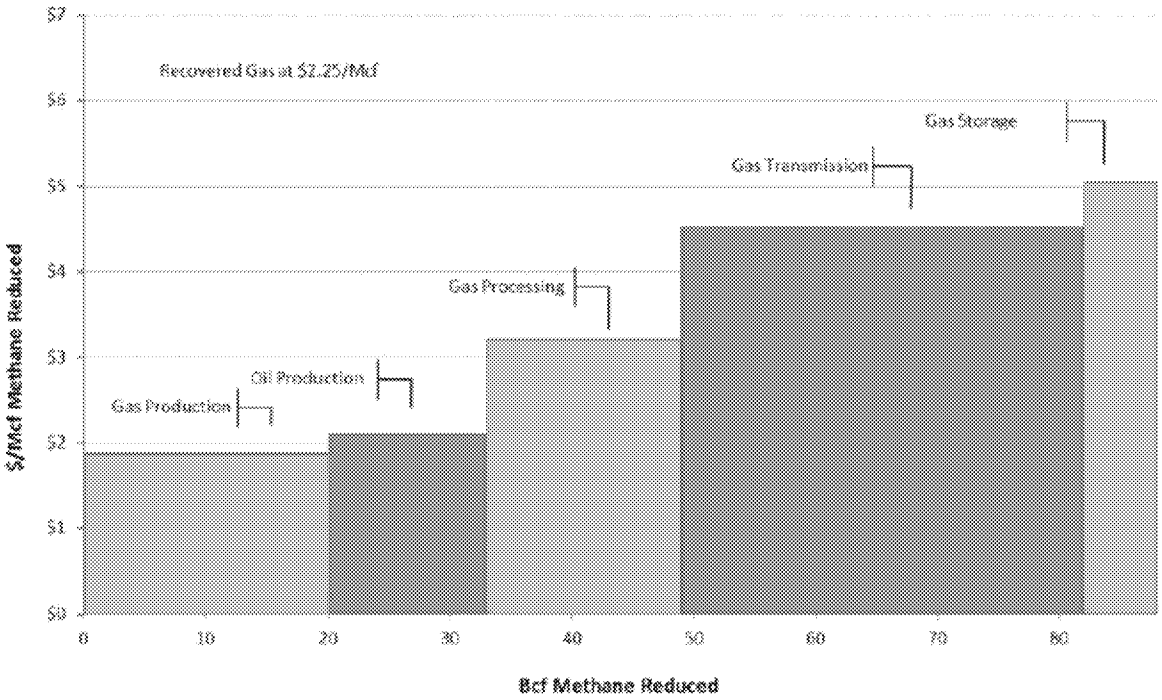

Source: ICF 2016a.

National Aggregate Marginal Abatement Cost Curve for Methane Abatement Technologies for the Oil and Gas Sector (ICF, 2016a)

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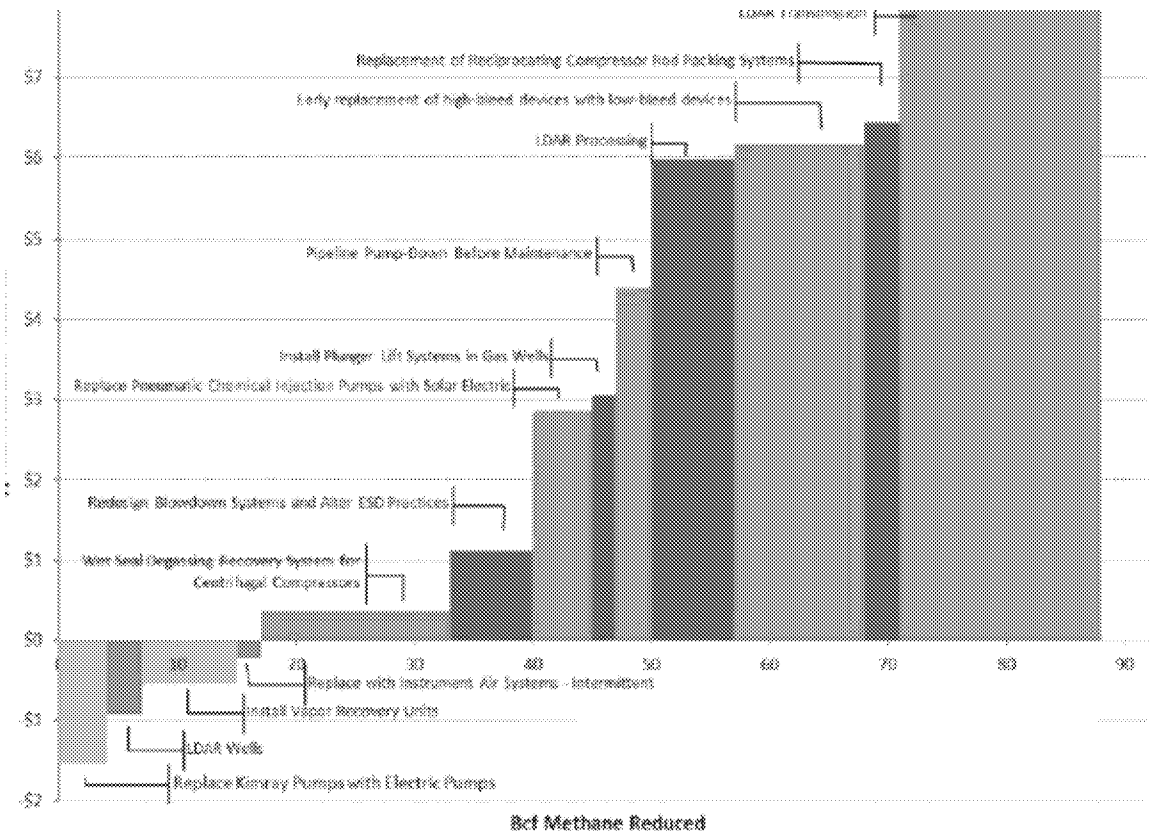

References

ICF (ICF International). 2016a. Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems. Washington, DC: ICF International. http://www.onefuture.us/wp-content/uploads/2016/06/ONE-Future-MAC-Final-6-1.pdf.

Munnings, C., and Krupnick, A., 2017, Comparing Policies to Reduce Methane Emissions in the Natural Gas Sector", Resources for the Future; 42 p.

US Environmental Protection Agency (US EPA). 2007. Leak Detection and Repair, A Best Practices Guide, Washington, D.C., 52 p.

4.0 Lessons Learned

Author Conclusions:	The authors concluded on (9) main points during their study: 1) US EPA likely underestimates methane emissions from the US natural gas sector, even though inventory operations improves every year; 2) Each of the natural gas subsectors—production, processing, transmission and storage, and distribution emits a significant amount of methane emissions;

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	3) There is significant heterogeneity in methane leak abatement costs across the four natural gas subsectors (production, processing, transmission and storage, and distribution; 4) There is wide variety in the costs of methane leak abatement technologies; 5) There is a wide variety in the methane emissions by facility location; 6) Super-emitters (SE) account for most of the methane emissions; 7) Super-emitters are divided into three categories: chronic, episodic, and stochastic. Chronic SE emit at a predictable and relatively static rate. Episodic SE emit at a high rate but only for brief periods such as during normal maintenance events with uploading and blowdown operations. Stochastic SE are created by leaks that result from operating errors and equipment malfunctions that are more difficult to predict than the other SE leaks and can occur in a seemingly random way; 8) Of the more than 1 million gas and oil wells operating in the United States, most are marginal wells with production of less than 90 Mcf per day; cumulatively, these marginal wells represent 10 percent of production and are typically owned by small firms with 12 or fewer employees. Regulation of these operators may not be good policy due to limited methane leak reduction potential; and 9) Currently there are institutional barriers to methane capture. In most states, public utility commissions do not allow local distribution companies to fully recover costs associated with repairing pipeline leaks so economic incentives are not in place to reduce methane. Likewise other tax incentives, cap-and-trade and other policies should be evaluated.
Methane Team Conclusions:	Since US EPA (2007) best management practices for leak detection and repair (LDAR) was published, new optical leak detection technologies have been developed – both as hand-held instruments and for use with drones, satellites, and planes. These new technologies should be used to assist Super-Emitters, the companies producing most of the volume of leaked methane. Methane leak detection and repair policy needs updating by US EPA and others to economically incentivize the super-emitters to reduce leakage. The article provides a framework for discussion, and notes that over-regulation of small oil and gas producers won't have a large impact on methane leak reduction. Likewise, the downstream operations leaks more and the repair costs are

	significantly more per Mcf methane reduced ($5/Mcf Methane reduced) than compared to the upstream oil and gas operation subsector (about $2/Mcf methane reduced). The downstream distribution business is typically run by utility companies with stockholders, they are not encouraged to detect and repair leaks due to outdated cost recovery policies. In sum, the new methane leak detection technologies should be integrated into an updated best management practices document. The 9 findings provided by the authors offer a focus for policy makers on where to focus the energy of leak detection to be economically feasible to minimize the most methane at a reasonable cost.

Reviewer: James A. Jacobs, P.G., C.H.G., Director, Tamalpais Community Services District, Mill Valley, CA 94941; jjacobs@tcsd.us

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Case Study – Generic Outline – Sydney Marlborough

Case Study Name: Monte Carlo Simulation Evaluation of Gas Imaging Technology

Author/s & Affiliation/s: David Epperson

Industry Sector: Oil & Gas

Technology: Simulation

3. Background

The primary objective of the study was to identify the level of performance at different monitoring frequencies, necessary for Gas Imaging or similar technology to provide equivalent environmental protection to quarterly monitoring. The secondary objective was to identify the potential performance of Gas Imaging technology.

Location:

Sector:	N/A
Facility Type:	N/A
Acres:	N/A
Volume:	Modeled 500, 1000, and 10,000 ppmv
Owner/Responsible Party:	N/A
Description:	N/A

Site Complexities:

Other Pollutants:	None
Characteristics:	Steady State, Constant mass
Other:	

4. Technology Utilized

Technology:	Usage Reason:	Effectiveness:
EPA Monte Carlo Software	Model leaks under current work practices and compare to alternate work practices	Study lead to the acceptance of Gas Imaging technology approval

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3.0 Assessment

Performance:	
Interferences/Limitations:	Study requires 10 assumptions within the model.
Improvement:	
Cost:	Variable based on study size
Technology Maturity Level:	EPA approved protocol
Technology Readiness Level:	Currently utilized
Alternatives:	Newer models with graphic interface, Maximum likelihood estimation models, Bayesian Statistical Modeling.

5.0 Lessons Learned

Author Conclusions:	Mass emission rate for a given AWP monitoring frequency and Method 21 was precise. Both AWP and CWP identified all of the largest simulated mass emissions rates. AWP, by design, did not identify any leakers below the leak definition being tested. This is consistent with interpretations of the equivalent AWP leak definitions; namely, that for Gas Imaging technology, a bi-monthly (or more frequent) monitoring frequency exceeds the level of equivalent environmental protection for CWP leak definitions of 500 ppmv and 1,000 ppmv, and a quarterly monitoring frequency may provide equivalent environmental protection for the CWP leak definition of 10,000 ppmv.
Methane Team Conclusions:	Gas Imaging or similar technology provides equivalent protection to method 21. The Monte Carlo Simulation could be used to evaluate new technologies as compared to the current work practice. This method has already been shown to be an acceptable study to prove equivalency to established practices.

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Appendix B. NORTH AMERICAN INDUSTRY CLASSIFICATION SYSTEM (NAICS) AND U.S. STANDARD INDUSTRIAL CLASSIFICATION (SIC) SYSTEM SOURCE CLASSIFICATION CODE (SCC) LIST LOOKUP TABLE

B.1 NAICS SIC SCC Insert Table Here

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Appendix C. TEAM CONTACTS

[Place this appendix before the glossary. Include team leaders, PAs, and especially knowledgeable team members who are willing to serve as contacts. For each contact, provide name, agency or affiliation, address, phone, fax, e-mail.]

Contacts:

Lisa Dorman, Methane Co-Team Leader
PA Department of Environmental Protection
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Appendix D. GLOSSARY

A

Air Drilling

Air drilling—also known as pneumatic percussion drilling[1] —is an underbalanced drilling (UBD) technique in which gases, usually compressed air or nitrogen, are used to cool the drill bit and lift the cuttings of a wellbore in place of conventionally used liquids

B

ED_002880A_00084675-00211

Appendix E. ACRONYMS

APC	air pollution control
ARAR	applicable or relevant and appropriate requirement
.	
.	
VO	volatile organic
VOC	volatile organic compound

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Message

From: Theresa Pugh [Pugh@theresapughconsulting.com]
Sent: 12/20/2018 4:25:26 PM
To: Wehrum, Bill [Wehrum.Bill@epa.gov]; Culligan, Kevin [Culligan.Kevin@epa.gov]; Woods, Clint [woods.clint@epa.gov]; Swanson, Nicholas [Swanson.Nicholas@epa.gov]
CC: Hambrick, Amy [Hambrick.Amy@epa.gov]
Subject: OOOO(a) Comments: Methane and cross walk issues to ACE
Attachments: attachment 1.pdf; ATT00001.txt

Good morning.

These comments were filed this week on methane [OOOO(a)] NSPS for oil and gas. These comments primarily focus on fugitive methane leaks from natural gas pipelines and compressor stations- serving electric power.

There is a connection between the ACE regulation and OOOO(a) on natural gas because, as we are learning, there is a significant relationship between the two industries. Just look at the pipeline explosions over the last 6 months. Two of them caused gas curtailments for the power sector- even if for only a day or two.

A few of my opinions and recommendations might surprise you. My goal is to make certain the electric utilities remain reliable- regardless of fuel supply while co2 and methane are regulated. I am sure you want that too.

My ACE comments addressed some of the cross cutting issues with methane leaks but not in this level of detail as expressed in attached OOOOa comments.

Have an enjoyable holiday. I hope you all get some well deserved time off.

Thank you,

Theresa Pugh

Owner

Theresa Pugh Consulting, LLC

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703-507-6843

www.theresapughconsulting.com

~ a woman owned small business~

Sent from mobile device, please excuse typos.

COMMENTS TO U. S. ENVIRONMENTAL PROTECTION AGENCY

REGARDING

RECONSIDERATION OF THE NSPS

FOR OIL & GAS INDUSTRY'S METHANE

60 CFR PART OOOO(A) OF CLEAN AIR ACT

EPA-HQ-OAR-2017-0483

FRL-9984-43-OAR RIN 2060-AT54

Document Number 2018-20961
December 17, 2018

and Relevant to EPA's

Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; and Revisions to New Source Review Program

Commonly Called the Affordable Clean Energy Rule or ACE Rule

(Oct. 31, 2018)

Docket Number EPA-HQ-OAR-2017-0355

83 Fed. Reg. 44,746 (Aug. 31, 2018)

Submitted by
President/Owner
Theresa Pugh Consulting, LLC
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ED_002880A_00084701-00001

Introduction

Theresa Pugh Consulting, LLC is a consulting firm representing public power (locally owned or governmental) electric utilities, oil and gas industry companies, pollution monitoring technology, and manufacturing companies interested in natural gas supply, pipeline safety and electric reliability. Theresa Pugh has 30 years' experience before U. S. EPA on behalf of a number of industries. She is a non-paid advisor to North American Electric Reliability Corporation (NERC) and one of the contributing authors of the NERC Single Point of Disruption Study (SPOD) on bulk electric and natural gas infrastructure, Nov. 2017. These comments are submitted by Theresa Pugh based upon years of regulatory advocacy before U. S. EPA. These comments do not purport to reflect the individual views of any electric utility clients or co-generators.

Theresa Pugh Consulting met with EPA technical and senior staff on OOOO(a) reconsideration of the rule to discuss related Affordable Clean Energy Rule (ACE) on September 25, 2018. These comments are to augment those initial discussions and preliminary materials provided to the docket in the ACE rule.

With one exception, the comments address the midstream pipeline delivery or gas transmission process and not upstream oil and gas methane leak detection and repairs. See page 10 for comments addressing low production parties.

Reconsideration of Rule is Justified and Consistent with Executive Orders and Administration's Call for Common Sense Solutions

Commenter supports regulatory reform and revisions to existing regulations under a reconsideration processes conducted under proper notice and comment. This reconsideration follows the requirements for notice and comment (including public comments) Administrative Procedures Act and shows good cause there should be no opposition to a revised rule. In this case, it is possible that some of the topics offered in these comments offer new information or evidence of the relationship between oil and gas regulations to address methane leaks [Section 0000(a)] and power sectors being regulated for CO_2 that justify reconsideration. Administrative Procedures Act states:

> [T]he agency must show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better, which the conscious change of course adequately indicates.

EPA should recognize that former President Obama issued Executive Order 13563 that requires "retrospective analyses of existing rules" as an important component to improve regulation and regulatory review. In that executive order, similar to the Executive Orders issued by President Trump, agencies were encouraged to "modify, streamline, expand or repeal" significant

regulations[1] that are "outmoded, ineffective, insufficient or excessively burdensome". In this case, the actions of Congress and three Presidents may be called upon as justification to allow some variability in the timing for compliance deadlines.

Commenter has no opposition to slight adjustments made for oil and gas sector compliance dates where conformity, capital expenditures, manpower in rural locations or where weather impedes repairs based upon arbitrary deadlines. Reconsideration process is also consistent with broader policy objectives expressed in Administration's Executive Order 13783 and 13807.

However, because of the relationship between the increasing reliance upon natural gas for the electric power sector, commenter recommends a very skilled and narrow adjustment to methane leak and repair compliance dates to ensure that there is no indirect and unexpected downtimes or natural gas delay or curtailment delays for natural gas-fired power plants. Concern are higher where power sector is served by any **one** of: natural gas pipeline, natural gas storage, or critical compressor station due to fugitive methane leaks that are not large enough to be adequately regulated by state or Pipeline and Hazardous Materials Safety Administration (PHMSA)'s leak regulations.

Reconsideration of Endangerment Determination

No review of EPA's Endangerment Determination[2] for Public Welfare is needed.

Section 111 and 112 and Ever the Twain Shall Meet

Historically industries have been regulated under Section 111 and 112.

Why EPA's OOOO(a) Rulemaking Process Matters to the Electric Utility Sector and the Relevance Regulating Electric Utility Sector

State air authority agencies should be given flexibility in the electric utility's 111(d) rulemaking on what determines the "remaining useful life" of the electric power plant's coal-fired unit. For some electric utilities the remaining useful life is a simple decision based upon electric demand and how much electric demand can be met through Demand Side Management, Combined Heat & Power with industrial/commercial customers, replacement with natural gas or combined renewables with natural gas for peaking. Currently electric load is flat in most states and at most electric utilities. This may change over the next few years—although EIA has predicted electric load to remain flat for at least ten years. Perhaps the greatest unknown is the future of electrified vehicles to replace liquid fuel vehicles. This commenter has no expertise on electric vehicles and when, or if, they will be commonly used by consumers and indirectly increase electricity demand.

For some electric utilities planning to replace older coal-fired plants with natural gas the "remaining useful life" might be affected by the permit approval by FERC or states for the **natural gas infrastructure** (mostly pipelines and compressor stations) to deliver the natural gas to the electric sector. This did not seem like a significant issue in 2013-2015 when EPA was considering the NSPS regulation for the electric utility sector. Nor did it seem as significant

[1] Executive Order 13771 issued January 30, 2017

[2] December 7, 2009.

when EPA first proposed a methane NSPS for the oil and gas sector in 2015. At that time the focus was on the tremendous new volume of natural gas supply and changes in the electric market. Since 2015 it has become increasingly difficult for any parties (upstream, midstream, downstream and electric utilities) to know with certainty that natural gas pipelines and compressor stations will get FERC certificate of need approval, state Public Utility Commission approval, and pass all relevant state permitting agencies. Recent delays in building gas infrastructure to serve the power sector are often caused by challenges at the state or Federal level under National Environmental Protection Act (NEPA), Clean Water Act Section 404, challenges to right of way authority, allegations about noise[3], or other complaints. Moving forward, there will be an increased relationship between the readiness of the natural gas infrastructure delivery system to the power sector—regardless of the overall abundant supply of natural gas in North America.

This commenter asks EPA to give consideration to the interconnectedness between its OOOO(a) final NSPS rule when placing deadlines on detecting and correcting or repairing methane leaks in the final rule. The final ACE rule will address power sector's NSPS for carbon dioxide (CO_2) by requiring heat rate improvements. Over time some power plant owners will determine that it is time to retire older coal plants and replace with more efficient and better ramping natural gas-fired plants. In some circumstances, the decision will be mostly influenced by the price of natural gas and the ability to ramp with intermittent wind or solar generation that will soon exceed 30% in many states. During this process of switching between coal and natural gas the readiness of the gas delivery infrastructure is key. Coal plant closures and the timing of a new NGCC plant may be offered to state agencies under the NSPS 111(d)'s "remaining useful life of the plant" discussions. In some cases, the electric utilities may be in a "wait and see mode" to determine if the pipelines needed to delivery gas to the new power plant have been permitted by all relevant agencies and successfully to meet the start date for operation. Perhaps state agencies will expect verification of plans to build gas pipelines or sign firm contracts to show sincerity if more time is needed or for leniency in the 111(d) process. In some cases, the plan for coal-fired power plant shut down may need to be submitted confidentially to state agencies as some power companies seek to negotiate best financial terms with multiple gas providers and do not want public notice of this shut down timing during negotiations.

There is a "handshake" or connection between these two rulemakings and U. S. EPA and states need to consider that methane leak repairs on new compressor stations and new pipelines might have some impact when serving existing power plants if the timing for repairs are not scheduled properly (i.e. during shoulder season for both segments of the energy sector). Further, it is not clear from this reviewer of the proposed OOOOa reconsideration if the new commencement date for pipelines and compressor stations was triggered from the original September 18, 2015 date or from October 15, 2018 date. EPA should make that date clear in Final rule and to communicate that to North Electric Reliability Corporation (NERC) and to state pipeline inspectors through direct communication to National Association of Pipeline Safety Regulatory (NAPSR).

[3] Noise at compressor stations is regulated by both FERC and local implementation of sound under Clean Air Act.

North American Electric Reliability Corporation (NERC)'s Observations:

For many new and existing gas-fired power plants there are multiple pipelines to serve natural gas from local underground storage to the power plants. Redundancies in gas transmission routing is good from a delivery perspective—no differently than having coal delivery options by more than one railroad or barge company. However, not all gas-fired power plants have redundancies in gas storage or gas pipeline transmission (transportation).

North American Electric Reliability Corporation (NERC)'s November 2017 study[4] offers documentation, diagrams, charts, and maps showing that there are many operational connections. While it is easy to assume there is no connection between the two energy segments (provider of gas and power sector as a customer of gas), there is a clear connection. If anything, NERC's report shows a more conservative view of the connection between the two sectors because NERC only looks at bulk electric relialibty. NERC does not study localized and intermittent service disruptions of electric service when there are force majeure events for smaller utilities or for one natural gas fired unit owned by a larger utility with a fleet of units which to select and use.

> Commenter observes that EPA staff working on both NSPS OOOO(a) and ACE may discuss NERC's 2017 study with NERC staff and see confidential maps developed by Argonne National Lab for NERC to demonstrate how many power plants are currently served by only one pipeline, one compressor station with no redundancies, or a single storage location in direct proximity to the power plant. While the reconsideration of deadlines in OOOO(a) may be appropriate, perhaps it is NOT wise to lengthen compliance times for leak identification and repair for those gas pipelines and compressor stations that serve a power plant with no additional service redundancies until additional redundancies have been installed.

The September 13, 2018 pipeline explosion events in Boston suburbs demonstrate the relationship between electric power distribution and natural gas transmission even if the tragedy was relatively localized with no loss of bulk electric—and caused by a natural gas local distribution company. The September explosions were caused by over-pressurization[5] on Columbia Gas (MA) forced National Grid to shut off electric service to many thousands of homes in three communities for safety reasons for more than 24 hours. While the weather was mild in September and the electricity was restored to the homes within approximately three days, this event demonstrates that the two sectors will be more intrinsically connected in the future. National Grid's generation portfolio was untouched by the natural gas explosions but the state required a curtailment of electricity for up to three days. One can only imagine how difficult it would have been to move many thousands of people to emergency response shelters after 5:00 PM if the tragic accident, requires the local electric utility to shut down electricity for

[4] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

[5] NTSB Preliminary Accident Report for Merrimack, MA pipeline explosions https://www.ntsb.gov/investigations/AccidentReports/Pages/PLD18MR003-preliminary-report.aspx; October 12, 2018

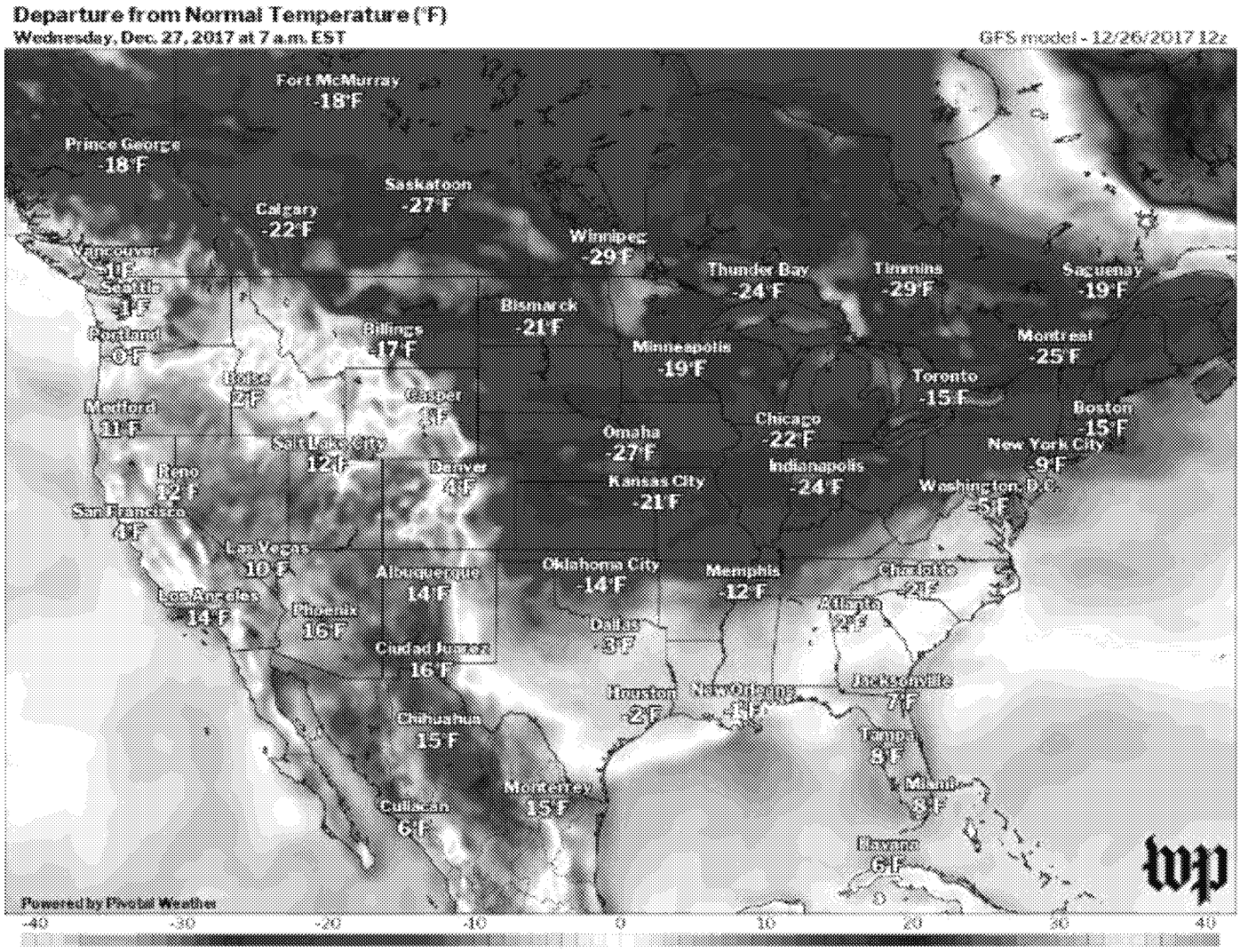
days or weeks. One also wonders about human safety or additional damage to homes if the event had happened between December 2017-Jan. 2018 when weather was as low as -5 degrees in some Boston locations.

To prove the point, see Washington Post's weather map from December 26, 2017 showing extreme cold temperatures that ultimately lasted for almost one week across most of the U. S. A power loss due to generation force majeure curtailment or a force majeure event on a leak repair for natural gas pipelines, compressor stations or even natural gas storage locations could be very dangerous for electric utilities during wintertime peak use. Perhaps the event might be less dangerous for summertime peak—but still very dangerous in states such as Arizona, Texas, South Carolina, Florida, etc. during summer electric peak. As NERC points out, many power plants do not have secondary fuels on site or are permitted to use oil during summer ozone season.

Thus, this commenter recommends that EPA's OOOOa rule should allow for the leak repairs on the gas transmission (pipelines) system to be coordinated during shoulder season and during times of other repairs to minimize disruptions to the gas delivery system. However, this commenter believes that leak detection and repairs on sole-source pipelines and compressor stations for power sector (including independent power producers, community aggregators and power islands at factories selling power to the market) should be required MORE frequently as EPA required in its 2016 rule. **For gas pipelines and compressor stations serving electric utility with no other delivery redundancies, the fugitive leak and repair obligations should remain the same as in the 2016 final rule.** Most power plants are not dependent upon only one pipeline but, where they are, leak detection and repairs schedules should be retained as under the prior rule unless redundancies are provided. Those redundancies could mean pipelines redundancies, local natural gas storage such as Liquified Natural Gas (LNG), or permitting dual fuel if the generating unit has the ability to burn an alternative fuel (oil, biomass) for service for one week at peak. Redundancy does not mean being reliant upon line packing the pipeline for "storage' for power plants >50 MW. **Also, while firm, uninterruptible contracts are desirable for many reasons, firm contracts cannot prevent gas delivery disruptions—especially when the power plant has only one gas pipeline, one gas storage location and perhaps has a compressor station within 70 miles of the power plant with no alternative compressor stations**.

(Continued on page 7)

Map 1 Illustrating Winter 2017-2018 Temperature Issues Supporting Why the Gas Pipeline Infrastructure Readiness and Local Reliability Matters in ACE Proposed Rule

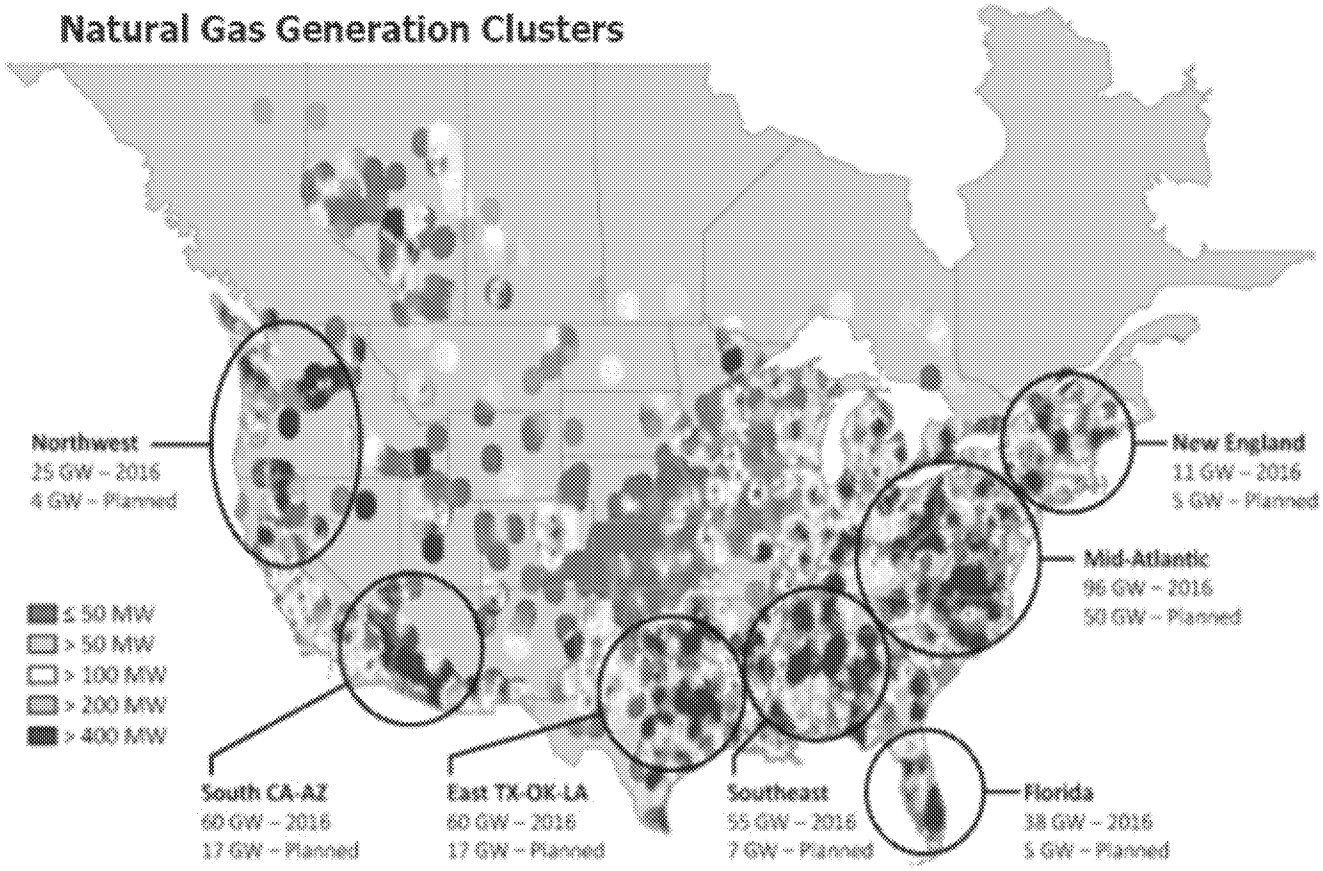


Source: Washington Post, "Unforgiving Cold Snap Will Engulf Eastern-Two-Thirds of the Nation Through New Year's Day, December 26, 2017; Washington Post online, 1:57 PM

(Continued on page 8)

NERC Single Point of Disruption Study, November 2017 Illustrates Areas Where NERC Believes There Could be Localized Natural Gas Infrastructure Problems Resulting in Localized Electric Reliability Problems

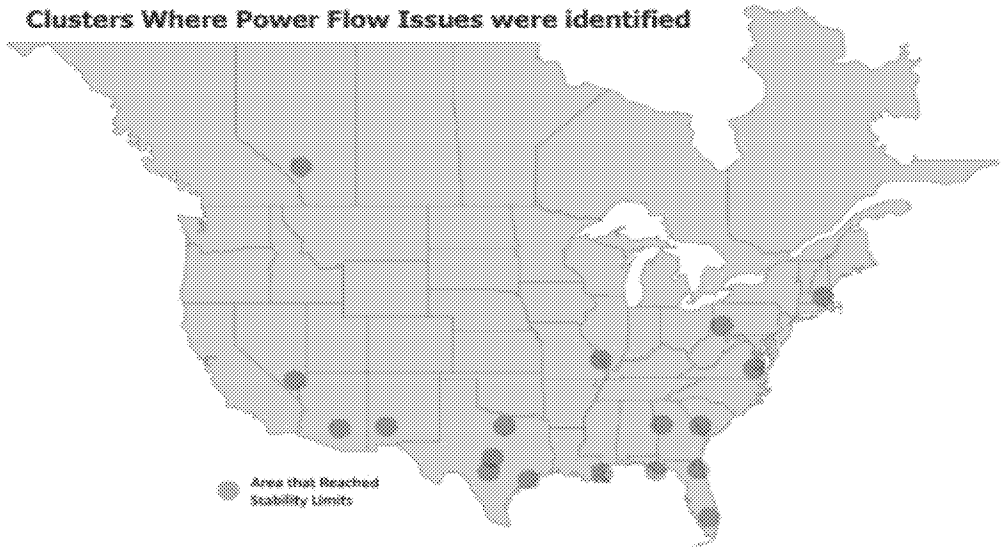
Map 2



NERC, Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, Page 17
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

(Continued on page 9)

Map 3



NERC, Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, Page 20
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

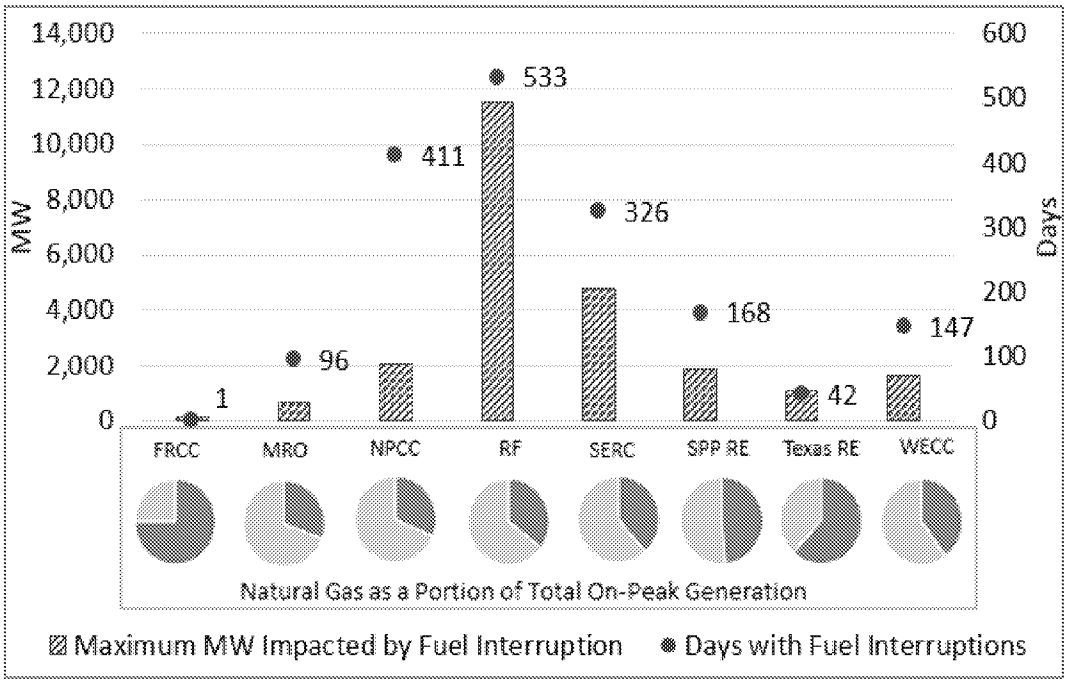
Further, should EPA implement 111(d) rulemaking on methane from the natural gas delivery system (transmission pipelines and compressor stations) for existing sources, the inter-relatedness of the two industry segments will be even more significant. Another way of seeing the potential local reliability issues when considering "remaining useful life of plant" is to review NERC's Table 1.3 on page 7 from their Nov. 2017 report.

Table 1

Table 1.3: Natural Gas Supply Characteristics by Area			
Region	Number of Generators with One Connection	Generation Capacity with One Connection (MW)	Number of Major Supply "Trunk" Lines Serving Area
Northwest	16	4,963	24
Southern California and Arizona	20	11,430	13
East Texas, Louisiana, and Oklahoma	40	17,965	60
Southeast	68	46,124	35
Florida	38	31,049	7
Middle Atlantic	22	12,244	9
New England	35	13,103	6
Northeast	49	21,903	20

Source: NERC, Single Point of Disruption Study
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

Table 2



Note that GADS database indicates days not hours or minutes of fuel disruption

Source:
NERC GADS Outages of Natural Gas Generation due to "Lack of Fuel"

Technologies for Leak Detection and Leak Repairs Should be Expansive

Commenter believes that U. S. EPA has been too narrow in its application of ways that companies may identify leaks and repair those leaks. The original proposed rule identified optical gas imaging. In the last four years there have been many new sensors and adjustments to existing Supervisory Control and Data Acquisition (SCADA). Commenter encourages EPA to have broadest technology terms to allow more effective and lower cost technologies, devices, and adaptations of existing sensors connected to SCADA (including through new algorithm and Artificial Intelligence) to identify the methane leaks. In time, artificial intelligence (AI) may also be used to identify methane and differentiate it from other methane in ambient air surrounding regulated facilities. In time, fugitive leak repairs may be addressed through technologies and devices not yet known. These types of emerging technological improvements should be allowed to be used as long as the system is verifiable.

Single Comment to Address Upstream Low Production

1. EPA asked for comments on low production for to methane leak detection and repair (reporting) costs.

Commenter cannot provide leak detection, repair and pipeline investment costs and defers to the professional societies and advocacy organizations on these details. However, commenter has personal experience in Texas' conventional oil and gas or non-conventional production. Unlike conventional oil and gas, shale oil and gas are not as easy to estimate production based upon drilling reports. Like liquid beverage with pressure in an enclosed bottle or can, the volume might appear larger on the first opening as the liquid comes rushing out. In fact, decline rates take a few weeks (perhaps months) to gauge properly. **Decline rates mean a great deal in new shale production as to whether the producer wants to invest in any long-stranding economic commitments—whether that is to bring in production water from offsite, build pipelines to gather or processing facilities, etc.** There are many wonderful aspects to having enormous new shale production options in North America. However, the decline rate on each shale area can vary wildly. **EPA should have a reasonable solution to allow sufficient time for producers to determine what is viable before having to invest in frequent leak detection and repair processes.**

Commenter defers to upstream industry experts but can observe that many new shale formations have producers that need as long as 12-18 months to review production reports and watch for decline rate and related price volatility in natural gas commodities. Commenter recommends that EPA give low-production wells as long as 18 months to determine whether they will actually produce from those wells before installing methane leak/repair and reporting obligations. **Requiring methane leak/leak repair costs could inadvertently strangle off new production that is "on the bubble".** Many larger companies undertaking methane recovery where this allows them to recover methane for sale into market and these companies may drive lower cost methane leak and repair technologies. But not all independent, low volume production parties have the manpower, capital and large variety of options available to larger corporations with large fleets of drilling and production equipment, proximity to gathering/processing facilities, etc. Commenter recommends that upstream producers all be regulated but that smaller or low production facilities have more time for making decision on investing in and implementation of methane leak identification and leak repairs. Obviously, the amount of time should not economically disadvantage the larger, corporate producers but give a bit of flexibility to low production well owners. It is a delicate balancing act to select the right timing for additional time. Pugh believes that up to 18 months is fair because the economic market of natural gas between $50-55.bbl (West Texas) and < $3.00 mcf natural gas price is inherently "on the bubble" for producers. These prices have dominated many investment decisions over the last three years.

- **EPA asks in related question, who should qualify for being called "low production" facilities**. The fairest way to define low production is to use the IRS definition used for standard tax purposes.
- **How to avoid a "loophole for producers to avoid methane leak and repair obligations"** The best way to avoid a loophole allowing producers too much time to avoid methane leak and methane repair obligations is to require the final OOOO(a) obligations to kick in at 18 months or less time if producer's associated gas meets production reporting requirements to U. S. EIA or state oil and gas regulatory agency.

Conclusion

Methane can still be regulated to meet the requirements for NSPS under Section OOOO(a) without wasting time to review the endangerment determination or review downstream uses of oil and gas under any CO_2e or Social Cost of Methane economic review within this regulation. There is no reason to delay the effectiveness date of a final rule in 2019 beyond the standard sixty-day compliance time given that the industry has had almost two years under the prior rule.

EPA can make modest changes in the reconsideration process resulting in a rule that can reduce methane emissions and provide sensible ways to reduce fugitive methane emissions from compressor stations and pipelines.

EPA staff working on both the OOOO(a) regulation and the ACE regulation for power sector should become familiar with the interconnection between the two sectors. OOOOa regulation should reduce fugitive methane leaks but not creating more opportunities for downtime in natural gas infrastructure delivering product to a market that will have both summer and winter peaking season and hours. **Further, those power plants served by only one compressor stations or by one pipeline that fugitive emission leak detection and repairs are made slightly more frequently than for other pipelines with multiple redundancies for environmental reliability, and public safety purposes.** When redundancies are built, the frequency should be adjusted. While this commenter might prefer that pipeline regulations are primarily the purview of PHMSA, this commenter has no opposition to addressing fugitive emissions from gas transmission systems since not all pipeline leaks are covered by PHMSA. Nor is it clear if all states have similar pipeline safety requirements to address fugitive leaks or larger leaks that would require state regulatory action equal to those intrastate pipelines regulated by PHMSA.

EPA should seek to communicate with NERC and relevant parties at PHMSA on this rulemaking given recent developments demonstrating the relationship between the gas transmission system and gas fired power plants and industrial gas consumers. **It is clear that EPA, NERC, FERC, state pipeline/storage regulatory agencies and PHMSA need to enhance their communications on specific regulatory options and policies.**

Message

From: Davis, Alison [Davis.Alison@epa.gov]
Sent: 10/19/2018 9:52:09 PM
To: Kenney, James [Kenney.James@epa.gov]
CC: Hambrick, Amy [Hambrick.Amy@epa.gov]
Subject: For your review. Thank you
Attachments: Shale Insight 10.23.18 EPA_v1 (002).pptx

PROPOSED IMPROVEMENTS 2016 NEW SOURCE PERFORMANCE STANDARDS

Presentation for Shale Insight 2018

SHALE INSIGHT™ 2018 | October 23-25, 2018

Oil and Gas Industry

Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines

Production & Processing

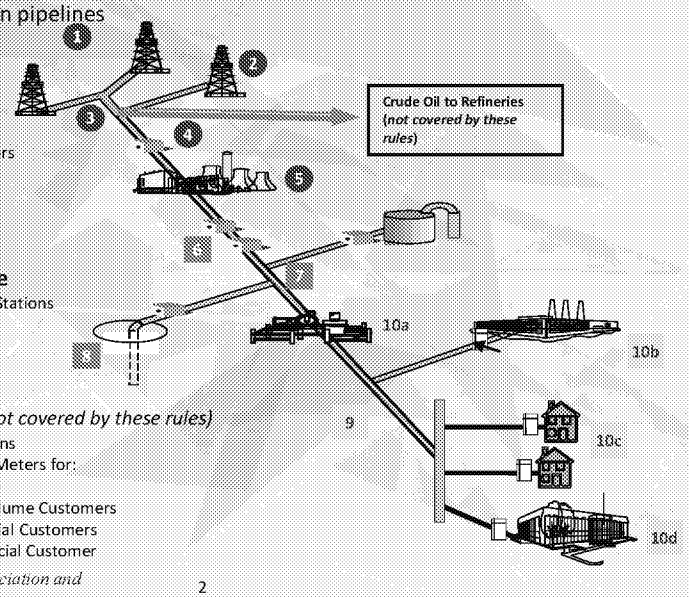
1. Drilling and Well Completion
2. Producing Wells
3. Gathering Lines
4. Gathering and Boosting Compressors
5. Gas Processing Plant

Natural Gas Transmission & Storage

6. Transmission Compressor Stations
7. Transmission Pipeline
8. Underground Storage

Distribution *(not covered by these rules)*

9. Distribution Mains
10. Regulators and Meters for:
    a. City Gate
    b. Large Volume Customers
    c. Residential Customers
    d. Commercial Customer



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

Actions at a Glance

- June 3, 2016: EPA issued New Source Performance Standards (NSPS) for the oil and gas industry
- April 18, 2017: EPA granted reconsideration of the fugitive emissions requirements in OOOOa
- June 5, 2017: EPA announced reconsideration on two additional requirements:
  - Well site pneumatic pumps standards; and
  - Professional engineer certification requirements for the design capacity of closed vent systems
- October 15, 2018: EPA proposed amendments and clarifications related to the specific reconsideration issues identified in 2017

2016 New Source Performance Standards In Review

- Set emissions limits for methane and VOCs
  - Owners/operators meet limits using technologies that are cost-effective and readily available
  - Types of sources subject to the 2012 NSPS for VOCs did not have to install additional controls to reduce methane; the same controls reduce both pollutants
- Covered additional sources beyond the 2012 NSPS:
  - Hydraulically fractured oil wells
  - Pneumatic pumps at well sites and gas processing plants
  - Compressors and pneumatic controllers at transmission and storage facilities
  - Fugitive emissions monitoring and repair at well sites and compressor stations

2018 Proposed Amendments

- On Sept. 11, EPA announced a number of proposed amendments to the 2016 rule
  - Address a range of technical issues in response to administrative petitions
  - Clarify certain requirements in the rule
  - Address implementation issues that have been brought to the Administration's attention since the 2016 standards were issued.
- EPA's regulatory impact analysis (RIA) estimates cost savings of up to $75 million per year, or a total of $484 million for the 2019-2025 period (3 percent discount rate)

2018 Proposed Amendments

Fugitive Emissions: Monitoring

- 2016 Rule
  - Well sites: semiannual
  - Compressor stations: quarterly
- 2018 Proposed Amendments
  - Well sites:
    - Non-low production well sites: annual
    - Low production well sites: biennial (once every other year)
    - Monitoring can stop once all major production and processing equipment is removed from a well site, resulting in a wellhead-only well site
  - Compressor stations: semiannual and annual (co-proposal)

2018 Proposed Amendments

Fugitive Emissions: Repair

- 2016 Rule
  - Repair all leaking components within 30 days of finding a leak
  - Resurvey to verify repair within 30 days of completing repair
- 2018 Proposed Amendments
  - Make first attempt at repair within 30 days of finding leak
  - Complete repairs within 60 days of finding leak

Note: A repair is considered complete following a resurvey verifying repair

2018 Proposed Amendments

Fugitive Emissions: Alaska

- 2016 Rule
  - *Well sites* on the Alaska North Slope
    - Initial monitoring:
      - Within 6 months of startup or by June 30, whichever is later (September – March startup)
      - Within 60 days of startup (April – August startup)
    - Annual monitoring thereafter
- 2018 Proposed Amendments
  - Expands well site requirements to *compressor stations* on Alaska North Slope

2018 Proposed Amendments

Emerging Technologies

- 2016 Rule
  - Provided details for owners/operations to apply for an alternative means of emission limitation (AMEL)
  - Required 12 months of site-specific field data
- 2018 Proposed Amendments
  - Streamlined application requirements
  - Added allowance for modeling results to supplement field data
  - Allows owners/operators to apply with technology vendors or trade associations

2018 Proposed Amendments

Equivalent State Programs

- 2016 Rule
  - Same AMEL application process used for emerging technologies
- 2018 Proposed Amendments
  - Would provide a separate application process for states to apply for alternative fugitive emissions standards
  - Proposing alternative fugitive emissions standards for specific states, including Ohio and Pennsylvania, to streamline applications for existing state programs

2018 Proposed Amendments

Pneumatic Pumps

- 2016 Rule
  - Required 95% control of emissions at well sites
  - Allowed PE to certify technical infeasibility of routing emissions to control for brownfield sites
- 2018 Proposed Amendments
  - Would provide technical infeasibility assessment for all well sites
  - Would provide option for in-house engineer to certify assessment

2018 Proposed Amendments

Professional Engineer Certifications for Closed Vent Systems

- 2016 Rule
  - Required PE certification for closed vent systems
- 2018 Proposed Amendments
  - Would provide option for in-house engineers (appropriate expertise) to evaluate designs of closed vent systems and certify design/capacity sufficiency

2018 Proposed Amendments

Other Proposed Amendments

- Would clarify requirements or improve implementation:
  - Definition of "capital expenditure" as it relates to equipment leaks at onshore natural gas processing plants
  - Definitions related to well completions
  - Calculation of "maximum average daily throughput" for storage vessels

Next Steps

- Public hearing will be held in Denver
  - Information will be posted: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas
- Public comment period open until December 17, 2018
  - Docket ID: EPA-HQ-OAR-2017-0483
- The Agency continues to consider other policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and gas sector, and will address these in a separate proposal at a later date.

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Message

From: Kenney, James [Kenney.James@epa.gov]
Sent: 9/6/2018 9:19:42 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
Subject: FW: HEI Energy Research Program-Agenda and Materials for September 12-13, 2018 Workshop
Attachments: HEI Energy Research Program September Workshop Participant Packet.pdf; HEI Bibliography 6 September 2018.pdf

Hi Amy,
I'm sending you the information Clint received from HEI so you have it. Thanks for your help today with the bio.
Thanks,
Jim
Desk/Mobile: (202) 768-2618

From: Kathryn E. Liziewski [mailto:kliziewski@healtheffects.org] **On Behalf Of** Donna Vorhees
Sent: Thursday, September 6, 2018 3:08 PM
Subject: HEI Energy Research Program-Agenda and Materials for September 12-13, 2018 Workshop

Good afternoon,

In preparation for HEI's Exposure Workshop being held September 12-13, 2018 in Austin, Texas, please find the agenda and other preparatory materials attached. We look forward to seeing you in Austin.

Thank you,

Donna Vorhees

Donna J. Vorhees, ScD
Director of Energy Research
Health Effects Institute
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INTRODUCTION TO THE BIBLIOGRAPHY

LITERATURE TO UNDERSTAND POPULATION-LEVEL EXPOSURES RELATED TO DEVELOPMENT OF OIL AND NATURAL GAS FROM UNCONVENTIONAL RESOURCES

Introduction:

This bibliography contains a preliminary list of exposure characterization and health peer-reviewed studies and non-peer-reviewed reports collected by the HEI Energy Research Committee to date. This body of literature includes research conducted in the United States, and that characterize potential agents of exposure to human populations on the regional and local scales. This bibliography is not finalized; please send suggestions of papers that the Committee should review.

Organization:

This bibliography is organized by topics relevant to potential human exposures related to development of oil and natural gas from unconventional resources (UOGD). Publications may be listed in duplicate if they are relevant to more than one topic area.

Topic Area Descriptions:

- **Identification and Properties:** Literature that characterizes chemicals used in UOGD processes, found in wastewater, or detected in air.
- **Fate and Transport:** Literature that characterizes how chemicals released into air and water travel and degrade in the environment.
- **Air Quality:** Literature that assesses air quality through monitoring, modelling, emissions inventories, or a combination of methods. This section is organized by both the primary agent of focus within a given study and by the location of the study.
- **Water Quality and Use:** Literature that assesses surface, ground and drinking water quality through monitoring, modelling, emissions inventories, or a combination of methods. This section is organized by the location of the study and whether the study focuses on surface, drinking or ground quality. This section also includes a sub-section on water use and water resource management.
- **Sediment and Soil Quality:** Literature that characterizes chemicals found in soil or sediment.
- **Noise and Light:** Literature that characterizes noise and light from UOGD operations.
- **Waste Management:** Literature that characterizes chemicals found in wastewater and that assess waste management practices, including transport, storage, disposal and reuse.
- **Toxicity:** Toxicological studies and toxicity reviews of agents associated with UOGD, including chemicals found in drilling fluids, fracturing fluids, wastewater and air.
- **Human Exposure:** Literature focused on estimating potential exposures to human populations, including personal exposure and biomonitoring studies. This section also includes reviews of potential human exposure pathways.
- **Public Health:** Literature that quantifies or qualitatively assesses potential impacts of UOGD on human health. These include human health risk assessments, analytical and descriptive epidemiology studies, community-engaged research, and health reviews.
- **Oil and Gas Worker Health:** Literature focusing on occupational exposure to agents associated with UOGD, including epidemiology studies, modeling studies and reviews.
- **Individual and Community Well-Being:** Literature that assesses public perception, potential community change and economic impacts of UOGD.

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~ We welcome your suggestions of papers that should be included.
Please send to dvorhees@healtheffects.org ~

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STRESSOR AND EXPOSURE CHARACTERIZATION

STRESSOR IDENTIFICATION AND PROPERTIES

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Health Effects Institute's Energy Research Program

Preparatory Materials for a Workshop:

Planning Research to Understand Population-Level Exposures Associated with Onshore Development of Oil and Natural Gas from Unconventional Resources

September 12-13, 2018 | Austin, TX

The Hilton Austin, 500 East 4th Street, Austin, Texas, 78701

The purpose of HEI's Energy Research Program is to identify and conduct highest priority research on the potential population exposures and health effects from the onshore development of oil and natural gas from shale and other unconventional resources (UOGD) across the United States.

This package contains:

→ **Workshop agenda** along with the **workshop's purpose** and **charge questions** for all participants

→ **Description of HEI's research planning workshops and expected products** with an introduction to the Energy Research program and a description of how this workshop will facilitate research planning by HEI's Energy Research Committee

→ **HEI Energy Research Committee Biographies**

→ **Workshop Speaker Biographies**

→ **Participant list** including individuals representing academia, government, non-governmental organizations, and industry

→ **Logistical information**, including a map and directions from the airport to the workshop venue and transportation options

→ **Coming separately...a brief report summarizing the Committee's progress**

A separate attachment to this email contains:

→ **Bibliography** and an accompanying brief overview of the its contents

Participants' role at the workshop:

- Contribute your perspective to the Committee's impartial, interdisciplinary review and interpretation of exposure, toxicity, and risk assessment literature.
- Lend your voice to the Committee's planning for original population-level exposure research to fill important knowledge gaps.

A buffet lunch will be provided on September 12th and a breakfast on September 13th

For more information: Donna Vorhees (617-488-2317; dvorhees@healtheffects.org)

The Health Effects Institute (www.healtheffects.org) is an independent, non-profit research institute funded jointly by government and industry to provide credible, high quality science on air pollution and health for air quality decisions. Periodically, HEI also receives funding from foundations for special projects. HEI sponsors do not participate in the selection, oversight or review of HEI science, and HEI's reports do not necessarily represent their views.

HEI Research Planning Workshop

Understanding Population-Level Exposures Associated with Onshore Development of Oil and Natural Gas from Unconventional Resources

Hilton Austin, 500 E 4th St., Austin, TX 78701
September 12-13, 2018

WORKSHOP AGENDA

Purpose of Workshop:

The workshop provides an opportunity for the Energy Research Committee to hear from a broad range of stakeholders about their expert opinions and perspectives on the literature, important knowledge gaps, and research priorities along with the criteria used to define the priorities. This workshop is the second of two workshops. Presentations and group exercises will build on progress made at the July workshop.

The Committee will consider information received during the workshop as it conducts its own review of the literature and formulates research priorities for population-level exposure research. With the benefit of an interdisciplinary group of experts at the workshop, HEI's Energy Research Committee expects to complete a framework of potential human exposure pathways that can serve as a roadmap for research planning.

Workshop Charge Questions:

1. How can existing data be leveraged to understand potential exposures from UOGD?
2. What potential UOGD exposures are not well understood with existing data and merit original research?
    a. What exposure pathways and phases of UOGD should be the focus?
    b. In conducting such research, what are your recommendations for considering regulatory, environmental, and industry practice variability over time and across regions?
    c. What is the value of the research for decision-makers (e.g., regulators, industry, community members, and scientists conducting research)?

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Workshop Chair: George Hornberger, Chair, HEI Energy Research Committee

September 12, 2018 (10:30am to 5:30pm)

TIME	TOPIC	SPEAKER
10:00-10:30 AM	*Registration*	
10:30-11:00 AM	**INTRODUCTIONS AND WORKSHOP OVERVIEW**	
10:30-10:40	Welcome	Bob O'Keefe, Vice President, HEI
10:40-11:00	Introductions	George Hornberger, Chair, HEI Energy Research
11:00-11:10	Workshop Objectives and Charge Questions	Donna Vorhees, Director of Energy Research, HEI
11:10 AM -12:00	**THE COMMITTEE'S PROGRESS**	
11:10-11:45	Overview of exposure literature review and research planning	George Hornberger and HEI
11:45-12:00	Discussion	
12:00-1:00	*Lunch*	
1:00-3:00 PM	**PANEL DISCUSSION: Federal and State Oil and Gas Policy - Trends and Research Needs**	
Panel Talking Points:		*Panelists (in alphabetical order):*
1. HEI's Energy Research Committee is charged with recommending population-level research to understand potential human exposures associated with onshore unconventional oil and natural gas development in the United States. To do so, the Committee needs a clear understanding of current national- and state-level oil and natural gas regulations and guidance. For this reason, we ask each panelist to describe current oil and natural gas policy in their jurisdiction and anticipated future trends, focusing on policies most important for the protection of public health (by minimizing exposures). **2.** HEI's Energy Research Committee has been charged with recommending high priority research that is relevant to policy decisions. To this end, we ask each panelist to advise the Committee about human exposure research related to unconventional oil and natural gas development that they would find most useful.		Megan E. Garvey (Senior Counselor to the Regional Administrator Region 8) Michael E. Honeycutt (Director, Toxicology Division, Texas Commission on Environmental Quality) James C. Kenney (Senior Policy Advisor for Unconventional Oil and Gas, Office of Congressional and Intergovernmental Relations, USEPA) Scott Thompson (Executive Director, Oklahoma Department of Environmental Quality) Martha Rudolph (Director of Environmental Programs, Colorado Department of Public Health and Environment) Clint Woods (Deputy Assistant Administrator, Office of Air and Radiation, USEPA)
3:00-3:30 PM	*Break*	
3:30-5:15	Group Exercise #1 followed by facilitated discussion	
5:15-5:30	*Discussion; wrap up for the day; review plan for day 2*	

September 13, 2018 (8:00am to 12:00pm)

TIME	TOPIC	SPEAKER
7:00-8:00 AM	*Breakfast*	
8:00-10:15 AM	**DATA MINING: How can we leverage the data that already exists?**	
8:00-8:25	Working smarter not harder, unearthing oil and gas data using intelligent geoinformatics	Kelly Rose (U.S. Department of Energy, National Energy Technology Laboratory)
8:25-8:45	Stalking the Wild Dataset: Informing Policy with Evidence	Kate Konschnik (Duke University)
8:45-9:05	Using Geochemistry Data to Identify Groundwater Quality Issues in Shale Gas Production Areas	Tao Wen (Pennsylvania State University)
9:05-9:25	Existing VOC Measurements from the Colorado Front Range's Oil and Natural Gas Region: Availability, Value, and Limitations	Rebecca Hornbrook (University Corporation for Atmospheric Research)
9:25-9:45	Oil and Gas Emission Inventories and Applications for Estimating Impacts to Health and Welfare	Tom Moore (Western States Air Resources Council) and John Grant (Ramboll)
9:45-9:55	Filling in the Gaps in Monitoring Data with Satellite Imaging	Alan Krupnick (Resources for the Future)
9:55-10:15	Air Quality Data from CDPHE's Community Exposure Investigations	Tami McMullen (Colorado Department of Public Health and Environment)
10:15-10:20 AM	*Brief Break before Breakout Groups*	
10:20-11:50	Group Exercise #2 followed by facilitated discussion	
11:50-12:00	Wrap-up with next steps in research planning and opportunities to comment before RFQ release	

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Research Planning Workshops

~Background Information~

Purpose of the Energy Research Program

The purpose of HEI's Energy Research Program is to identify and conduct highest priority research on the potential population exposures and health effects from the onshore development of oil and natural gas from shale and other unconventional resources (UOGD) across the United States. With resource development projected to continue, alongside growing efforts to switch to renewables and conserve energy, a source of high-quality, impartial science is needed to support decisions about how best to ensure protection of public health in the oversight and implementation of this development.

HEI's Energy Research Committee

The Energy Research Committee (the "Research Committee") is a body of subject-matter experts that independently defines and oversees the Energy Research Program.

- George Hornberger, Vanderbilt University, Director, Vanderbilt Institute for Energy & Environment, Nashville, Tennessee (Chair)
- Shari Dunn-Norman, Missouri University of Science and Technology, Rolla, Missouri
- Elaine M. Faustman, University of Washington–Seattle
- Howard Hu, University of Washington and University of Michigan
- Judy S. LaKind, LaKind Associates, LLC, Catonsville, Maryland, and Adjunct Faculty, University of Maryland–Baltimore
- Armistead (Ted) G. Russell, Georgia Institute of Technology, Atlanta
- Stefanie Ebelt Sarnat, Emory University, Atlanta, Georgia

The Workshops

General Approach

Two *Exposure and Risk Screening Workshops* will draw on existing knowledge, relevant data and literature regarding potential UOGD exposures to:

- Review what is known about potential UOGD exposures, their likelihood, and significance for health;
- Develop a conceptual model of potential exposures to UOGD;
- Discuss criteria for identifying and prioritizing research; and
- Provide advice to the Research Committee on exposure topics that warrant research.

The first workshop allows for reviewing the literature and identifying preliminary research priorities. Between the two workshops, the Research Committee will continue its review of the literature along with information and public comment received during the first workshop and subsequent public comment period. The second workshop allows for continued discussion of the literature and more refined research priorities for consideration by the Research Committee. Discussions and recommendations from both workshops will help to guide the Research Committee as it selects exposure topics that warrant study and prepares RFQs.

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Workshop Organization

July 11-12, 2018 Workshop
Denver, Colorado

- Review UOGD operations and trends affecting the potential for exposure
- Review and develop a conceptual model of potential UOGD exposures
- Discuss criteria for identifying and prioritizing research options
- Suggest priorities for research that the Research Committee should consider for funding

Summer 2018
Interim Analyses

- Conduct additional review of the literature to support discussion of research options at a second workshop

September 12-14, 2018 Workshop
Austin, TX

- Continue discussion of the literature
- Suggest priorities for population-level exposure research that the Research Committee should consider for funding

Participants

HEI seeks workshop participants that bring the necessary breadth of expertise and experience, along with an ability to impartially interpret and use scientific information. Participants will come from federal, state, regional, and local government, academia, industry, and non-governmental environmental, public health, and community organizations.

Products

HEI will summarize workshop proceedings in brief reports and oversee preparation of a peer-reviewed article that summarizes the literature review and recommendations for research priorities. Finally, but perhaps most important, based on the workshop discussions, the Research Committee will prepare a draft RFQ for exposure studies for review by sponsors before final issuance and solicitation of study proposals.

For More Information:

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Telephone: 617-488-2317
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Webpage:
https://www.healtheffects.org/energy

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ENERGY RESEARCH COMMITTEE BIOGRAPHIES

HEI Energy Research Program

George M. Hornberger (Chair)

Dr. Hornberger is a University Distinguished Professor at Vanderbilt University, where he directs the Vanderbilt Institute for Energy and Environment and has a shared appointment as the Craig E. Philip Professor of Engineering and as Professor of Earth and Environmental Sciences. Previously he was a professor for many years at the University of Virginia where he held the Ernest H. Ern Chair of Environmental Sciences. He has been a visiting scholar at the Australian National University, Lancaster University, Stanford University, the United States Geological Survey, the University of Colorado, and the University of California at Berkeley. Dr. Hornberger's research centers on the coupling of field observations with mathematical modelling. Recognizing that water resources are under pressure from many human activities from climate change to urban development, he pursues broadly interdisciplinary research focused on coupled natural-human systems. The goal of the research is to understand how climate, groundwater, surface water, and human abstraction of water interact in complex ways. Current projects include work in Sri Lanka on adaptation to drought and in the United States on how cities evolve water conservation practices. He has published extensively, with numerous scientific papers, book chapters, and books.

Dr. Hornberger has served on numerous boards and committees of the National Academies, most recently as chair of the Committee on "Future Water Resource Needs for the Nation: Water Science and Research at the U.S. Geological Survey" and chair of the Water Science and Technology Board. He has also served other organizations, for example, he chairs the Geosciences Policy Committee of the American Geosciences Institute and serves on various committees of the Geological Society of America, the American Geophysical Union, and other organizations. In 2015, he recently completed service as the chair of the Health Effects Institute Special Scientific Committee on Unconventional Oil and Gas Development. Before that in 2013, he chaired a related National Research Council Committee on Development of Unconventional Hydrocarbon Resources in the Appalachian Basin. He previously served as an editor on several highly regarded journals. Dr. Hornberger won the Robert E. Horton Award (Hydrology Section) from the AGU in 1993. In 1995, he received the John Wesley Powell Award from the USGS. In 1999, he was presented with the Excellence in Geophysical Education Award by the AGU and in 2007 he was selected Virginia Outstanding Scientist. Professor Hornberger was elected to the U.S. National Academy of Engineering in 1996. He was also elected a Fellow of the American Geophysical Union in 1994, the Association for Women in Science in 1996, and the Geological Society of America in 2005, received the William Kaula Award from the American Geophysical Union in 2010, and the Harvie Branscomb Distinguished Professor Award from Vanderbilt University in 2017.

Dr. Hornberger holds a B.S.C.E. in Civil Engineering and an M.S.C.E. in Hydrology from Drexel University and a Ph.D. in Hydrology from Stanford University.

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Shari Dunn-Norman

Dr. Dunn-Norman is Associate Professor and the former Program Head of Petroleum Engineering at the Missouri University of Science and Technology. Previously, she worked in both domestic and international assignments for the Atlantic Richfield Companies (ARCO), beginning her career as a summer field roustabout and advancing to Senior Operations Engineer at ARCO International. Dr. Dunn-Norman's research has focused on pipeline flow and leak detection, well construction for the protection of underground sources of drinking water, hydraulic fracturing, and well completions. She has over 25 years of combined academic, industrial and consulting experience in well design and well completion technology. She has published extensively, with numerous scientific papers and book chapters and co-authored a book on well construction.

Dr. Dunn-Norman is a member of the Society of Petroleum Engineers (SPE), where she has served on numerous committees. She was elected and currently serves as the National President of Pi Epsilon Tau, the Petroleum Engineering Honor Society. She is also a member and volunteer for the St. Louis Academy of Science and the Missouri Academy of Science. Dr. Dunn-Norman served on the U.S. Environmental Protection Agency Science Advisory Board 2011 Ad Hoc Hydraulic Fracturing Research Advisory Panel, which reviewed EPA's draft "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources." For more than 20 years, Dr. Dunn-Norman has taught numerous industrial short courses about production engineering and well completions for various companies, such as Petroleum ETC, a private corporation that operates events worldwide on topics ranging from multiphase pumping and artificial lift, to hydraulic fracturing; and Petroskills, a leading world organization in all areas of oil and gas training. Dr. Dunn-Norman has received numerous awards, most recently the Society for Professional Engineers' Distinguished Member Award in 2015 and several excellence in teaching awards.

Dr. Dunn-Norman holds a B.S. in Petroleum Engineering from the University of Tulsa and a Ph.D. in Petroleum Engineering from Heriot-Watt University, Edinburgh, Scotland.

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Elaine M. Faustman

Elaine M. Faustman is Professor in the Department of Environmental and Occupational Health Sciences and Director of the Institute for Risk Analysis and Risk Communication in the School of Public Health and Community Medicine at the University of Washington. Dr. Faustman's research includes quantitative risk assessment for non-cancer endpoints, molecular mechanisms of developmental and reproductive toxicity, and in vitro and molecular biological methodologies. She develops decision-analytic tools for communicating and translating new scientific findings into risk assessment and risk management decisions. Dr. Faustman directs the NIEHS/EPA-funded Center for Children's Health Research. She has served as Principal Investigator for the Pacific Northwest Center for the National Children's Study and has directed the Pacific Northwest Center for Human Health and Ocean Studies. The goals of Dr. Faustman's research are to discover the mechanisms that define susceptibility in at-risk populations and to provide linkages across disciplines. She has over 200 peer reviewed research publications and reports.

Dr. Faustman is an elected fellow of the American Association for the Advancement of Science and the Society for Risk Analysis. She has served on the USEPA Science Advisory Board. She previously chaired the National Academy of Sciences Committee on Developmental Toxicology and served as a member for the National Advisory Environmental Health Sciences Council, the National Institute of Environmental Health Sciences (NIEHS)-National Toxicology Program (NTP) Committee on Alternative Toxicology Methods, the NIEHS-NTP Board of Scientific Counselors, the National Academy of Sciences Committee on Toxicology, and the Institute of Medicine Upper Reference Levels Subcommittee of the Food and Nutrition Board. She has just completed two terms as Secretary General for the International Union of Toxicology. She is currently a member of the International Science Council World Data Systems Advisory Board. She served on the U.S. Environmental Protection Agency Science Advisory Board 2011 Ad Hoc Hydraulic Fracturing Research Advisory Panel, which reviewed EPA's draft Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources. Dr. Faustman also served on the executive boards of the Society of Toxicology, the Teratology Society, and the Society for Risk Analysis. She has served as an editor on several highly regarded journals. Dr. Faustman has been honored with numerous awards, most recently the 2016 Josef Warkany Lecturer Award from the Teratology Society, the Distinguished Achievement Award from the Society for Risk Analysis in 2014, and the University of Washington's Outstanding Teaching Award.

Dr. Faustman holds an A.B. in Chemistry and Zoology from Hope College and a Ph.D. in Pharmacology/Toxicology from Michigan State University.

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Howard Hu

Howard Hu is Affiliate Professor in the Department of Environmental and Occupational Health Sciences, the University of Washington School of Public Health, as well as Adjunct Professor in the Department of Environmental Health Sciences, University of Michigan School of Public Health. When he joined the Committee, Dr. Hu served as the founding Dean at the Dalla Lana School of Public Health at the University of Toronto (2012-2018). Previously, Dr. Hu was Professor of Occupational and Environmental Medicine at the Harvard School of Public Health and Associate Physician in the Channing Laboratory of the Brigham and Women's Hospital in Boston, Massachusetts (1990-2006), after which he was the NSF International Endowed Chair of the Department of Environmental Health Sciences and Professor of Environmental health, Epidemiology and Internal Medicine at the University of Michigan School of Public Health and Health System (2006-2012). Dr. Hu is a physician-scientist, trained as an internist, occupational and environmental medicine specialist, and epidemiologist. He founded an environmental epidemiology research group that, since 1990, has grown into a multi-institutional and international team of scientists devoted to gaining new insights into the impact of exposure to potential toxicants that are of critical importance to public health and medicine. His environmental and molecular epidemiologic research has focused on heavy metals, potential endocrine disruptors, other neurotoxicants, and carcinogens, with particular interest in exposures during sensitive life stages. Dr. Hu has published more than 300 original papers in the scientific literature, and co-authored and edited several books.

He has served on the Institute of Medicine's Board of Population Health and Public Health Practice, the Board of Environmental Science and Toxicology of the National Research Council, and on the National Advisory Environmental Health Sciences Council for the National Institutes for Health. In 2016, he was elected to Fellowship, Canadian Academy of Health Sciences. He also served as the founding medical editor of Environmental Health Perspectives, the official journal of the National Institute of Environmental Health Sciences (NIEHS). He currently serves on the Board of Directors of the Canadian Urban Environmental Health Research Consortium. Dr. Hu has received numerous awards, including most recently the Linus Pauling Lifetime Achievement Award, the Award of Excellence from the American Public Health Association, and the John R. Goldsmith Award for Outstanding Contributions to Environmental Epidemiology from the International Society for Environmental Epidemiology.

Dr. Hu holds a B.Sc. in Biology from Brown University, an M.D. from the Albert Einstein College of Medicine, and an M.P.H. and Sc.D. in epidemiology from the Harvard School of Public Health. He trained in internal medicine at Boston City Hospital and in occupational and environmental medicine at Harvard.

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Judy S. LaKind

Dr. LaKind is President of LaKind Associates, LLC, an Adjunct Associate Professor in the Department of Epidemiology and Public Health at the University of Maryland School of Medicine, and a Fellow-by-Courtesy in the Department of Applied Mathematics and Statistics at The Johns Hopkins University. Dr. LaKind has taught graduate level courses at The Johns Hopkins University and the University of Maryland in risk assessment and aquatic chemistry. Previously, Dr. LaKind was a geologist at the US EPA's Office of Federal Activities, where she was responsible for the evaluation of environmental impact statements and legislative reports. She is a health and environmental scientist with expertise in exposure science, assessment of human health risks, biomonitoring, scientific and technical analysis for regulatory support, and state-of-the-science reviews. Dr. LaKind has spoken and published extensively on children's exposures to environmental chemicals, the implications of uncertainty in the risk assessment process, weighing potential risks and benefits related to chemical use (for example, use of MTBE in gasoline, glycols in de-icing formulations, and chlorination of drinking water for zebra mussel control), the presence of environmental chemicals in human milk, and time-dependence and distributional analysis of exposure.

Dr. LaKind is President of the International Society of Exposure Science. She is a founding member of the International Society for Children's Health and the Environment and is a former member of Maryland's Children's Environmental Health and Protection Advisory Council, the Lead Poisoning Prevention Commission, and the Maryland Pesticide Reporting and Information Workgroup. She is a member of the World Health Organization Survey Coordinating Committee for the WHO Global Survey of Human Milk for Persistent Organic Pollutants (POPs), the HESI RISK21 Advisory Board, and the Maryland Department of Health and Mental Hygiene (DHMH) Cancer Cluster Advisory Committee. Dr. LaKind also served on the Institute of Medicine Committee on Blue Water Navy Vietnam Veterans and Agent Orange Exposure and the US Environmental Protection Agency Science Advisory Board Panel on Perchlorate - Approaches for Deriving Maximum Contaminant Level Goals for Drinking Water. Dr. LaKind has received awards, including the 2017 Society of Toxicology Regulatory and Safety Evaluation Specialty Section Award for Best Paper Contributing to the Field of Regulatory and Safety Evaluation in Toxicology and the 2015 EPA Scientific and Technological Achievement Award Level III for "Providing Critical Models and Information Needed for Exposure and Risk Assessments of Environmental Chemicals in Infants."

Dr. LaKind holds a BA in Earth and Planetary Sciences from Johns Hopkins University, an M.S. in Geology from the University of Wisconsin, and a Ph.D. in Geography and Environmental Engineering from Johns Hopkins University.

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Armistead (Ted) G. Russell

Dr. Russell is the Howard T. Tellepsen Chair and Regents' Professor at the Georgia Institute of Technology School of Civil and Environmental Engineering. Dr. Russell's research is aimed at better understanding the dynamics of air pollutants at urban and regional scales and assessing their impacts on health and the environment to develop approaches to design strategies to effectively improve air quality. He currently co-directs the NSF Sustainability Research Network "Environmentally Sustainable, Healthy and Livable Cities" project and co-directed the Southeast Center for Air Pollution and Epidemiology. His research interests include air pollution modeling, aerosol dynamics, atmospheric chemistry, combustion emissions control. He has published over 300 peer-reviewed journal articles, book chapters and major reports.

Dr. Russell is a Fellow of the American Society of Mechanical Engineering and the American Association for the Advancement of Science and is a National Associate of the National Academies. Dr. Russell was a member of EPA's Clean Air Science Advisory Committee (CASAC) and a member of the National Research Council's Board on Environmental Studies and Toxicology, and he continues to serve on associated committees. He chaired the CASAC NOx-SOx, Secondary NAAQS review panel, the Ambient Air Monitoring Methods Subcommittee, and the Council on Clean Air Compliance Analysis' Air Quality Modeling Subcommittee, and was on the Health Effects Institute's Report Review Committee. Dr. Russell has been honored with numerous awards, including the 2015 Distinguished Alumni Award from Washington State University, the 2013 Regents' Professor Award, and he was the Most Influential Individual to 2013 semifinalist for the Intel Science Talent Search.

Dr. Russell holds a B.S. in Mechanical Engineering from Washington State University, and an M.S. and Ph.D. in Mechanical Engineering from the California Institute of Technology, conducting his research at Caltech's Environmental Quality Laboratory.

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Stefanie Ebelt Sarnat

Dr. Sarnat is Associate Professor of Environmental Health at the Rollins School of Public Health of Emory University. Her epidemiological research focuses on examining health effects of ambient air quality using population- and panel-based approaches. She leads large-scale time-series studies of ambient air quality and acute morbidity, using emergency department visit data as an indicator of population health. Dr. Sarnat's work on these studies focuses on assessment of ambient air pollution mixtures and metrics of extreme heat, examination of the impacts of exposure measurement error on observed epidemiological findings, and assessing exposure and population factors that may modify health risk. Her studies also include prospective panel-based designs, using detailed field investigation methods to further understand environmental exposure factors and health effects among susceptible and vulnerable populations. She has published extensively in the peer-reviewed literature and has frequently been asked to speak on exposure and epidemiological topics.

Dr. Sarnat is a member of the International Society for Environmental Epidemiology, an editorial board member at Epidemiology, and an associate editor at the Journal of Exposure Science and Environmental Epidemiology. Dr. Sarnat participated on the National Research Council's Committee on Urban Meteorology: Scoping the Problem, Defining the Need and the Health Effects Institute's Review Panel on Ultrafine Particles. She has participated as an expert reviewer of drafts of the USEPA Integrated Science Assessments for particulate matter and nitrogen oxides. She serves as the Point of Contact for Emory University as an observer organization in the United Nations Framework Convention on Climate Change process. Dr. Sarnat has been honored with several awards, most recently the Department of Environmental Health Teaching Award at Emory University and a Supporting Paper for a Level III USEPA Scientific and Technological Achievement Award.

Dr. Sarnat holds a B.Sc. in Microbiology and Immunology and a M.Sc. in Occupational Hygiene from the University of British Columbia and a Sc.D. in Environmental Health from the Harvard School of Public Health.

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HEI Research Planning Workshop

Understanding Population-Level Exposures Associated with the Onshore Development of Oil and Natural Gas from Unconventional Resources

Austin, Texas
September 12-13, 2018

SPEAKER BIOGRAPHIES

Megan E. Garvey
Megan Garvey was appointed to her role as Senior Counselor to EPA's Region 8 Administrator in July of this year. Megan's focus is on Region 8 energy matters, NEPA and Environmental Justice. She also works closely with the Agricultural and Tribal Advisors of the Region. Before coming to EPA, Megan managed regulatory policy for an upstream oil and gas company and volunteered her time as a Commissioner on the Colorado Air Quality Control Commission. Previously, Megan worked for the State of Colorado: as an Assistant Attorney General at the Colorado Attorney General's Office (Air Quality Unit) and as the Compliance Unit Manager for the Air Pollution Control Division of Colorado's Department of Public Health and Environment. Megan started out her career practicing environmental law at a private law firm in Chicago, IL. Megan holds a B.S. in Environmental Studies from Loyola University Chicago and a J.D. from Chicago-Kent College of Law. Megan resides in Morrison, Colorado with her husband and two young sons.

John Grant
John Grant is a Managing Consultant at Ramboll where he has worked for 15 years developing emission inventory and emission control program analyses. He has developed dozens of region and project level oil and gas emission inventories and contributed to state of the science reports on oil and gas emission inventory methods and impacts. He also has extensive experience analyzing emission inventories to understand environmental tradeoffs associated with technological advancements such as vehicle and equipment electrification and adoption of emission control programs.

Michael Honeycutt, PhD
Michael Honeycutt is the director of the Toxicology Division of the Texas Commission on Environmental Quality (TCEQ). His career at TCEQ began in 1996, and he has managed the division of 14 toxicologists since 2003. His responsibilities include overseeing (1) health effects reviews of air permit applications, (2) review of the results of ambient air monitoring projects, and (3) reviews of human health risk assessments for hazardous waste sites. Dr. Honeycutt spearheaded the updating of TCEQ's Effects Screening Levels (ESLs), or toxicity factors for chemicals. The TCEQ ESL derivation procedure has undergone two independent external scientific peer reviews and multiple rounds of public comment (http://www.tceq.texas.gov/toxicology/esl/guidelines/about.html). Dr. Honeycutt serves as a technical resource for TCEQ management and staff on issues concerning air and water quality, drinking water contamination, and soil contamination. He also serves as an expert witness in public and state legislative hearings, participates in public meetings, and has conducted hundreds of media interviews. Dr. Honeycutt is an adjunct professor at Texas A&M University, has published numerous articles in the peer-reviewed literature, serves or has served on numerous external committees, and has provided invited testimony at Congressional hearings. He was recently appointed chairman of USEPA's Science Advisory Board. Dr. Honeycutt received his Bachelor's degree and Ph.D. in Toxicology from the University of Louisiana at Monroe.

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George Hornberger
(See separate compilation of biographies for HEI's Energy Research Committee)

Rebecca Hornbrook
Rebecca Hornbrook is a Project Scientist in the VOC Measurement Group in the Atmospheric Chemistry Observations & Modeling laboratory (ACOM) at the National Center for Atmospheric Research (NCAR) in Boulder, Colorado. Her research interests center on the atmospheric emissions and fate of volatile organic compounds (VOCs), both natural and anthropogenic. Dr. Hornbrook received her Ph.D. working with Dr. Jochen Rudolph at York University in Toronto, Canada in 2005, and has over 20 years of experience in the measurement and analysis of gas-phase VOCs. She has been involved in laboratory studies of processes involved in tropospheric oxidation of VOCs, including work she led developing the methodology for measuring stable carbon kinetic isotope effects in the reactions of non-methane hydrocarbons with OH radicals and Cl atoms. She also spent several years measuring hydroperoxy and organic peroxy radicals (HO2 and RO2) using Chemical Ionization Mass Spectrometry (CIMS), studying photochemical processes involved in VOC oxidation. In recent years at NCAR, Dr. Hornbrook has participated in the development and deployment of state-of-the-art instrumentation to measure VOCs in the atmosphere, contributing significantly to the measurement capabilities of the Trace Organic Gas Analyzer (TOGA), a fast online gas chromatograph-mass spectrometer, both in its measurement frequency and growing suite of quantified VOCs. As a member of the TOGA team, she has participated in a large number of NSF and NASA-funded field campaigns, both airborne and ground-based, including OASIS, BEACHON-ROCS, TORERO, DC3, NOMADSS, CONTRAST, FRAPPÉ, WINTER, ORCAS, and most recently, ATom and WE-CAN.

James C. Kenney
James Kenney is the Senior Policy Advisor for Unconventional Oil and Natural Gas at the United States Environmental Protection Agency. In this capacity, Jim coordinates unconventional oil and natural gas activities for the Office of the Administrator across EPA's program and regional offices. Externally, Jim works with oil and natural gas stakeholders on regulatory and policy matters to ensure responsible oil and natural gas development. Such stakeholders include: industry, trade associations, federal and state agencies, tribes, environmental non-governmental organizations (eNGOs) and the public. Within EPA, Jim's career has spanned multiple offices around the U.S., including: Denver, Colorado; Philadelphia, PA; and Washington, DC, helping him bring both a national and local perspective to his current work. Jim earned a Master of Science in Engineering and Bachelor of Science in Engineering Technology from Temple University in Philadelphia, PA. While he is an EPA Headquarters employee, Jim teleworks from Albuquerque, New Mexico where he and his family reside.

Kate Konschnik
Kate Konschnik directs the Climate & Energy Program at the Nicholas Institute for Environmental Policy Solutions at Duke University and is a Senior Lecturing Fellow at Duke Law School. Konschnik's work focuses on options for public electric utility regulation and electricity market reforms given emerging technologies and de-carbonization goals. Konschnik has also worked extensively on effective governance of unconventional oil and gas production and transport. Konschnik joined Duke from Harvard Law School, where she founded and directed the Harvard Environmental Policy Initiative and taught as a Lecturer on Law. Previously, Konschnik was Chief Environmental Counsel to U.S. Senator Sheldon Whitehouse, and an Environmental Enforcement Trial Attorney at the U.S. Department of Justice.

Alan Krupnick
Alan Krupnick is a Senior Fellow at Resources for the Future. Krupnick's research focuses on analyzing environmental and energy issues, in particular, the benefits, costs and design of pollution and energy policies, both in the United States and abroad. He leads RFF's research on the risks, regulation and

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economics associated with shale gas development and has developed a portfolio of research on issues surrounding this newly plentiful fuel. Krupnick also served as senior economist on the President's Council of Economic Advisers, advising the Clinton administration on environmental and natural resource policy issues. In 2011 he was elected President of the Association of Environmental and Resource Economists and earlier that year was named an AERE Fellow.

He has served on the Editorial Boards of a number of journals. He co-chaired a federal advisory committee counseling the U.S. Environmental Protection Agency on the implementation of new ozone and particulate standards. He is a regular member of expert committees from the National Academy of Sciences, the USEPA and various Canadian government and non-governmental institutions. Krupnick also consults with state governments, federal agencies, private corporations, the Canadian government, the European Union, the Asian Development Bank, the World Health Organization, and the World Bank. He received his PhD in Economics from the University of Maryland in 1980.

His primary research methodology is in the development and analysis of stated preference surveys (such as contingent valuation and choice experiments), which include eliciting preferences for reductions in mortality risks, environmental risks, tradeoffs involved in improving community drinking water quality with respect to removal of carcinogens versus microbiological agents, and most recently, the risks from shale gas development as seen by experts and the general public.

Tami McMullin
Tami McMullin currently serves as Colorado's state toxicologist, where she also manages the Oil and Gas Health information and Response Program at the Department of Public Health and Environment (CDPHE). She leads research on community health exposures and technical evaluation of the literature on the public health effects potentially associated with oil and gas exposures. Prior to joining CDPHE, Tami worked as a toxicologist and risk assessor in the chemical industry for over a decade where she conducted regulatory testing and safety assessments. Dr. McMullin earned her Bachelor's degree in biology at the University of California San Diego and her Doctoral degree in Environmental Health and Toxicology from Colorado State University.

Charles Thomas (Tom) Moore, Jr.
Tom Moore works for the Western States Air Resources (WESTAR) Council as manager of the Western Regional Air Partnership (WRAP) air quality program, a voluntary partnership of states, tribes, federal land managers, local air agencies and the U.S. EPA, whose purpose is to understand current and evolving regional air quality issues in the context of the Clean Air Act (CAA) and the National Environmental Policy Act (NEPA). His regional analysis and planning support work is conducted through management of a series of interrelated contractor-supported regional projects for the WESTAR and WRAP membership. These diverse and complex projects cover ambient monitoring data analysis, emissions inventory preparation and analysis, regional photochemical grid modeling and source apportionment results, and satellite air quality data. He has worked extensively with both the activity and emissions estimation techniques for electrical generating units, wildland and agricultural fire emissions, oil & gas exploration and production emissions, and ozone and regional haze analysis needs and planning requirements, in support of air quality management programs across the West. A principal emphasis of his work from 2002 to the present is support of Regional Haze planning for the more than 100 Class I areas in the WESTAR-WRAP region. Key western U.S. air quality expertise includes oil & gas production emissions, wildland fire emissions and impacts, regional haze sources and transport, and impacts on the Ozone National Ambient Air Quality Standards from various sources and scales.
He has a B.S. in Physical Geography from Arizona State University in Tempe, with an emphasis on meteorological and glacier field studies, and climate data analysis projects, as well as additional graduate coursework related to air pollution and climate. He has lead numerous air pollution monitoring studies

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and analysis projects, held management positions in state and local government, and worked as an environmental consultant. Before re-joining the WESTAR staff in 2013, he worked for the Western Governors' Association from 2002-13 coordinating and managing WRAP activities. From 1990 to 2001, he designed and managed air quality monitoring and data analysis activities for the Arizona Department of Environmental Quality, where he led the development and implementation of the haze monitoring networks in both urban and remote areas throughout the state. Tom also worked previously for the WESTAR from 1994-96 on an inter-agency personnel assignment, leading a WESTAR project to advise EPA on western U.S. topics and issues with implementation of the national Particulate Matter health and welfare standards.

Robert O'Keefe

Robert O'Keefe is responsible for management of key programs at HEI, including the Institute's global program to assess the health effects of air pollution in developing countries. He also provides leadership in implementing HEI's ongoing research and review programs on the health impact of particulates, ozone air toxics and other pollutants, and emerging technologies and fuels, including those driven by climate concerns. He oversaw the Institute's efforts to define and implement a program of research on Accountability, a first-of-its-kind program designed to understand the health impacts of environmental regulation. He is regularly called on to address prominent institutions, including the U.S. Congress, the European Parliament, the National Academy of Science's National Research Council and Institute of Medicine, and many other domestic and international bodies. In 2009 he was invited by the Woodrow Wilson Center to address its congressional forum as a "Scholar on the Hill." He is currently a member of the U.S. EPA's national Clean Air Act Advisory Committee and is Chair of the Board of Directors of Clean Air Asia. Before coming to HEI he served for nine years at the Massachusetts Department of Environmental Protection, as Assistant Deputy Commissioner for Policy and Program Development and as Director of Planning and Budget. Mr. O'Keefe played a significant role in gaining passage and funding for major state programs, including the Massachusetts State Superfund law, the Safe Drinking Water Program, and the design and funding of Massachusetts' implementation of the 1990 Clean Air Act amendments.

Kelly Rose

Kelly Rose is a geo-data science researcher with the National Energy Technology Laboratory's (NETL) Research Innovation Center. Her research at NETL is focused on using geologic and geospatial science to reduce uncertainty about, characterize and understand spatial relationships between energy, engineered-natural systems at a range of scales. Her work involves development of new data-driven methods and tools for analysis of offshore energy, oil & gas, rare earth element, groundwater, carbon storage, and geothermal systems. Rose's research interests also include development of software driven solutions to common science-data curation, discovery and inter-operability challenges. She has served on advisory committees including the Department of Interior's National Geologic and Geophysical Data Preservation Program, United Nations Environmental Programme's global outlook on methane gas hydrates, and the University of Southern California's Induced Seismicity and Reservoir Monitoring Consortiums. She is associate editor for the Journal of Sustainable Energy Engineering and is also NETL's Technical Portfolio Lead for the Advanced Offshore Energy Research Portfolio https://edx.netl.doe.gov/offshore. Rose is Principal investigator for NETL's Energy Data eXchange (EDX), an online, public and private research curation and virtual laboratory platform developed by Rose and the EDX team for DOE FE, https://edx.netl.doe.gov. Rose is co-author of 1 patented, 1 trademarked, 1 copyrighted, 10 custom tools, and more than 100 published technologies and studies. Throughout her career at NETL, Rose has had the honor of mentoring and working with more than forty-five STEM research interns and fellows. She holds geology degrees from Denison University, B.S., Virginia Tech, M.S., and Oregon State University, Ph.D.

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Anna Rosofsky
Anna Rosofsky is a Staff Scientist at HEI with expertise in environmental and spatial epidemiology. Rosofsky joined HEI in 2017 as part of the Energy Research Program. In this role, Rosofsky supports technical work within and implementation of the Strategic Scientific Research Agenda to understand potential human exposure and health impacts from unconventional oil and gas development. Rosofsky recently received a Ph.D. in Environmental Health from Boston University School of Public Health, where she studied spatiotemporal patterns of ambient air pollution exposure and early-childhood health impacts. Prior to her doctoral studies, Rosofsky investigated environmental health disparities at the Center for Puerto Rican Studies and at the Mosakowski Institute for Public Enterprise. She received an M.A. in Environmental Science and Policy from Clark University.

Martha E. Rudolph
Martha Rudolph is the Director of Environmental Programs for the Colorado Department of Public Health and Environment where she oversees the Air Quality, Environmental Health and Sustainability, Hazardous Materials and Waste Management, and Water Quality Divisions. Ms. Rudolph has been with the Department since 2007 and served as the Executive Director of the Department in 2010. In 2015/2016, Ms. Rudolph was President of the Environmental Council of States, the national non-profit, non-partisan association of state and territorial environmental agency leaders. She currently serves on the Board of Directors for the Environmental Research Institute of the States and is a co-chair of the ECOS Shale Gas Caucus. Previously Ms. Rudolph was the Chair of the ECOS Air Committee and the Vice Chair of the ECOS Planning Committee. She is a member of the Division on Earth and Life Studies of The National Academies of Sciences, Engineering, and Medicine, a state advisor for the Georgetown Climate Center, and a member of the American College of Environmental Lawyers. A graduate of the Georgetown University Law Center, Ms. Rudolph is an environmental attorney, and served for 14 years in the Colorado Attorney General's Office. She has been in private practice in Denver, and was an assistant general counsel for Kinder Morgan Inc., a natural gas and energy transportation company. Ms. Rudolph received her BA in International Affairs from the University of Colorado-Boulder and Doctor of Law degree from the Georgetown University Law Center.

Scott Thompson
Scott Thompson has served as the executive director of the Oklahoma Department of Environmental Quality since December 2013. In that role, Thompson has implemented new approaches to environmental permitting and enforcement in Oklahoma with the goal of helping make the state more prosperous and economically viable. Prior to becoming executive director, Thompson led DEQ's Land Protection Division, where he managed a diverse set of programs, including Superfund, Brownfields, Voluntary Cleanup, and Radiation Management. Thompson has a biology degree from Central State University. He also has a master's degree in environmental science from the University of Oklahoma.

Donna J. Vorhees
Donna Vorhees directs the Energy Research Program at HEI. She is leading an effort to implement a Strategic Scientific Research Agenda designed to understand potential human exposures and health effects from unconventional oil and gas development and how they might be prevented or minimized. Vorhees has 25 years of consulting experience, assessing multi-pathway chemical exposures in indoor and outdoor environments, quantifying human health risks, and communicating risks to affected communities in the United States on behalf of government and private clients and internationally on behalf of the United Nations Environment Program. She serves on the U.S. EPA Board of Scientific Counselors Subcommittee on Chemical Safety for Sustainability and previously served on National Research Council committees (Health Risks of Phthalates and Sediment Dredging at Superfund Megasites), other advisory committees, and peer review panels for numerous health risk assessments prepared by the U.S. EPA, the Consumer Product Safety Commission, and Health Canada. She is Adjunct

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Assistant Professor at the Boston University School of Public Health where she teaches Risk Assessment Methods. Vorhees received her ScM and ScD in Environmental Health from the Harvard School of Public Health.

Tao Wen
Tao Wen received his PhD in Geology from the University of Michigan in 2017 and is currently a Postdoctoral Scholar in the Earth and Environmental Systems Institute at Penn State University. He completed his B.S. degree in Environmental Sciences at the University of Science and Technology of China in 2011. He has extensively worked on characterizing the formation and migration of natural gas (conventional and unconventional) and has assessed the environmental impacts of hydrocarbon recovery activities on water quality across a few major shale plays (i.e., Antrim Shale, Barnett Shale, and Marcellus Shale) in the U.S. During his research, Tao has blended field geology, state-of-the-art geochemical analyses, as well as emerging data mining (big data) tools in his research. More details about Tao Wen can be found at http://jaywen.com/.

Clint Woods
Clint Woods serves as Deputy Assistant Administrator in U.S. EPA's Office of Air and Radiation. Prior to joining EPA in December 2017, Clint was the Executive Director of the Association of Air Pollution Control Agencies (AAPCA), a non-profit organization of state and local air quality agencies located in Lexington, Kentucky. While with AAPCA, he was also a member of U.S. EPA's National Advisory Council on Environmental Policy and Technology. Clint previously served as a professional staff member with the Committee on Science, Space, and Technology in the U.S. House of Representatives, the Energy, Environment, and Agriculture Task Force at the American Legislative Exchange Council, and Manager of Government Affairs with the Recreation Vehicle Industry Association. He holds an MA in international commerce and policy from George Mason University and a BA from the University of Mary Washington.

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HEI Research Planning Workshop

Understanding Population-Level Exposures Associated with Onshore Development of Oil and Natural Gas from Unconventional Resources

Austin, TX
September 12-13, 2018

PARTICIPANTS

Dr. John Adgate
Professor and Chair, Department of Environmental and Occupational Health
Colorado School of Public Health

Dr. David Allen
Melvin H. Gertz Regents Chair in Chemical Engineering
University of Texas Austin

Mr. Dan Arthur
Founding Member and Managing Partner
ALL Consulting

Mr. Bruce Baizel
Director, Energy Program, Oil & Gas Accountability
Earthworks

Mr. Rodney Barnwell
Counsel – Environmental & Safety
XTO Energy Inc.

Ms. Uni Blake
Scientific Advisor
American Petroleum Institute

Dr. Tiffany Bredfeldt
Toxicologist, Toxicology Division
Texas Commission on Environmental Quality

Dr. Adelita Cantu
Associate Professor
University of Texas Health San Antonio

Dr. Joan Casey
Postdoctoral Scholar, Environmental Health Sciences Division
University of California at Berkeley

Dr. Isabelle Cozzarelli
Hydrologist
United States Geological Survey

Dr. Elena Craft
Senior Health Scientist
Environment Defense Fund

Dr. Eric Daniels
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Dr. Dennis Devlin
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Dr. Nicole Deziel
Assistant Professor of Epidemiology
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Missouri University of Science and Technology

Mr. Steve Ellison
Attorney
ConocoPhillips

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^ Speakers and Panelists

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Environmental and Regulatory Policy Manager
Noble Energy

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Senior Director, Regulatory and Scientific Affairs
American Petroleum Institute

Mr. Dick Francis
Manager, Reglatory Policy
Shell Oil Company

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Senior Counselor to the Regional Administrator
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Manager (Retired)
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Research Director, Center for Science and Democracy
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Mr. Daniel Greenbaum
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^***Dr. George Hornberger**
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^**Dr. Rebecca Hornbrook**
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Affiliate Professor, Environmental and Occupational Health Sciences
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Partner
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^**Mr. James Kenney**
Senior Policy Advisor for Unconventional Oil and Gas
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^Mr. Tom Moore
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^ Speakers and Panelists

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BP Lower 48 Exploration and Production

^Mr. Clint Woods
Deputy Assistant Administrator, Office of Air and Radiation
United States Environmental Protection Agency

*** HEI Energy Research Committee Members
^ Speakers and Panelists

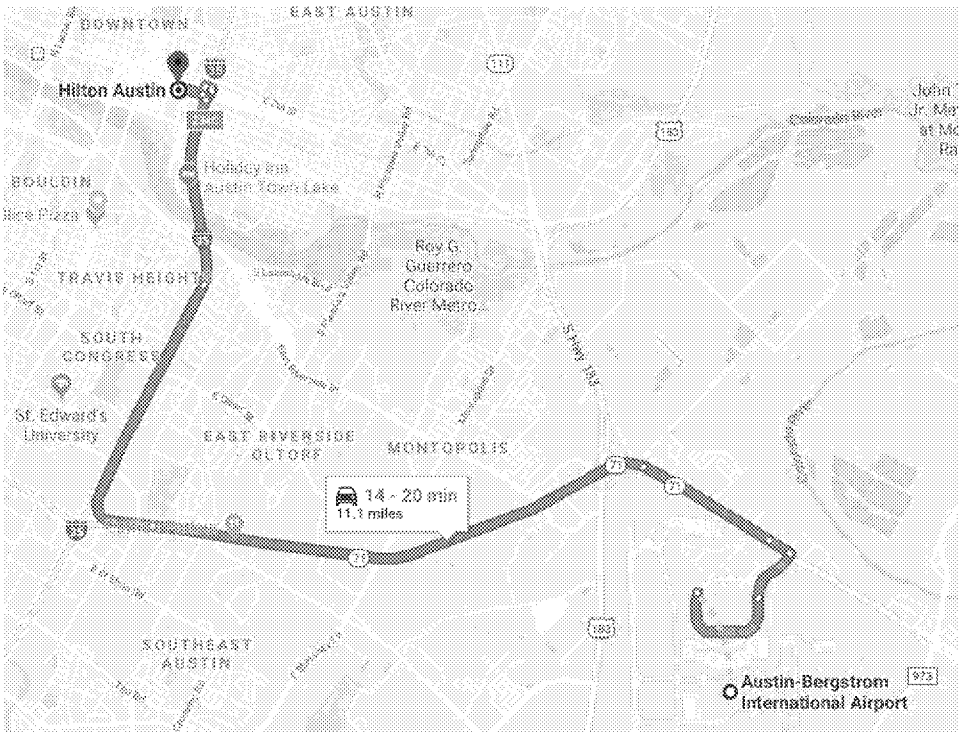
HEI Energy Research Program – Research Planning Workshop
September 12-13, 2018

Travel Guide

Hotel:
Hilton Austin, Governor's Ballroom – Salon B
500 East 4th Street, Austin, Texas 78701

Transportation between the Austin-Bergstrom International Airport and the Hilton Austin

The Hilton Austin is 11 miles from Austin-Bergstrom International Airport. Local taxis are available, as well as Uber, Lyft, and Ride Austin (a locally based ridesharing service like Uber and Lyft). A Lyft will cost ~$13 and will take about 20 minutes depending on traffic.



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Message

From: Hambrick, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=787B0A3376944FCABAED4F018432CF44-AHAMBRIC]
Sent: 11/30/2018 8:57:58 PM
To: Branning, Amy [Branning.Amy@epa.gov]
CC: Marks, Matthew [Marks.Matthew@epa.gov]
Subject: RE: UOG Workgroup FYI -->FW: Please Review by Dec. 3: Alternative Compliance Draft Paper

Thanks Amy , I really appreciate your quick review of the paper. I think we are all on the same page. I sent a note separately replying back to the folks on our internal call yesterday and cc'd you. For Matthew's benefit to, I paste that note below:

From: Hambrick, Amy
Sent: Friday, November 30, 2018 3:52 PM
To: Kenney, James <Kenney.James@epa.gov>; Mia, Marcia <Mia.Marcia@epa.gov>
Cc: Thoma, Eben <Thoma.Eben@epa.gov>; Chapman, Apple <Chapman.Apple@epa.gov>; Roberts, Cindy <Roberts.Cindy@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>
Subject: RE: Pre-Meet for ECOS Dec. 3: Alternative Compliance Draft Paper

All- Jim and I just spoke to Lia Parisien at ECOS (who has organized the meeting on Dec. 3). I wanted to let you all know the outcome of the call:

Ex. 5 Deliberative Process (DP)

Jim, please add anything I failed to capture for our call this afternoon. Happy to hear any additional thoughts from others.

Thanks,

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Branning, Amy
Sent: Friday, November 30, 2018 11:12 AM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Cc: Marks, Matthew <Marks.Matthew@epa.gov>
Subject: FW: UOG Workgroup FYI -->FW: Please Review by Dec. 3: Alternative Compliance Draft Paper
Importance: High

Hi Amy:

Ex. 5 Attorney Client (AC)

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Hambrick, Amy
Sent: Thursday, November 29, 2018 12:25 PM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: UOG Workgroup FYI -->FW: Please Review by Dec. 3: Alternative Compliance Draft Paper
Importance: High

FYI

From: Eck, Janet
Sent: Friday, November 23, 2018 9:54 AM
To: Lessard, Patrick <Lessard.Patrick@epa.gov>
Cc: Cozzie, David <Cozzie.David@epa.gov>; Koerber, Mike <Koerber.Mike@epa.gov>; Ashley, John <ashley.john@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>; McLamb, Marguerite <McLamb.Marguerite@epa.gov>; Pemberton, Wanda <Pemberton.Wanda@epa.gov>; South, Peter <South.Peter@epa.gov>; Srivastava, Ravi <Srivastava.Ravi@epa.gov>; Thompson, Fred <Thompson.Fred@epa.gov>
Subject: RE: 1-on-1 Items Request - Please provide input by 11/23

Hi Patrick, SPPD has several topics that we would like to have raised at the Monday discussion w/OAR:

Oil and Natural Gas Technical Package Comment Extension Requests: Attached is a pager discussing two comment extension requests we have received on the Oil and Gas Technical package.
Clint will discuss with Bill and get back to us. His initial impression was to not provide any extension.

EDF/ECOS Gas Caucus White Paper on Pathways for Alternative Compliance for Oil and Natural Gas Air Regulations:
Please see attached Background discussion and separately attached Air Compliance draft document.
Clint is fine with us participating – he does not need to participate.

Ex. 5 Deliberative Process (DP)

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Hambrick, Amy
Sent: Wednesday, November 21, 2018 11:37 AM
To: South, Peter <South.Peter@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>
Cc: Fruh, Steve <Fruh.Steve@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>
Subject: UOG Workgroup FYI -->FW: Please Review by Dec. 3: Alternative Compliance Draft Paper
Importance: High

Hi Pete and David-

I want to bring this email chain to your attention so you can flag it for the OAQPS IO and OAR IO.

Topic: EDF/ECOS Gas Caucus White Paper on Pathways for Alternative Compliance for Oil and Natural Gas Air Regulations (draft attached)

Background: A few months ago there was an EDF/ECOS kickoff call to discuss plans for a white paper on pathways for alternative compliance for oil and gas regulations. It is my understanding Eben Thoma/ORD, Jason Dewees/OAR, and Jim Kenney were invited to participate. The draft paper aims to assist state air regulators to implement rules that encourage innovation, and to help them act on applications for new methane reduction methodologies. To be more specific, the draft focuses on fugitives detection and repair, equivalency, monitoring and reporting, etc. It is both a policy and technical document and contains recommendations for regulators. EPA is being asked to review, provide feedback and discuss with the workgroup during the next call on **December 3 at 3-4 p.m. Eastern**. Additional questions will be discussed (1) Are the lessons learned clear? Does the paper capture your understanding of the challenges of alternative compliance, or is there anything else to add? (2) Are the recommendations compelling and comprehensive? Anything else to add? (3) What roles would others need to play to carry out the recommendations? What new roles would be required of your agency? (4) Are you familiar with any additional shared models that could inform the recommendation?

Ex. 5 Deliberative Process (DP)

Please let me know if you hear any or have any feedback that I should pass along to Jim Kenney. Thank you.

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Kenney, James
Sent: Friday, November 09, 2018 9:13 AM
To: Parikh, Pooja <Parikh.Pooja@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>; Mia, Marcia <Mia.Marcia@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>; Teichman, Kevin <Teichman.Kevin@epa.gov>
Cc: Thoma, Eben <Thoma.Eben@epa.gov>; Dewees, Jason <Dewees.Jason@epa.gov>
Subject: FW: Please Review by Dec. 3: Alternative Compliance Draft Paper
Importance: High

OAR, OECA, OGC and ORD Oil and Gas Contacts –
Please see the message below and the attached draft report: *Pathways for alternative compliance methodologies - A framework to advance innovation, environmental protection and prosperity.* The draft report is a work product of ECOS, member states and the EDF. It deals with LDAR, equivalency, monitoring and reporting, etc. It is both a policy and

technical document and contains recommendations for regulators. We are being asked to review, provide feedback and discuss with the workgroup.

Some of you may remember that we were asked to participate in a call on this effort in spring of this year. We agreed to listen in and learn about the effort to better inform our decision making about more robust participation. Eben Thoma/ORD, Jason Dewees/OAR, and I were invited to participate. Subsequent to that meeting, the ECOS effort paused while the EPA regulatory landscape was changing at the national level.

Ex. 5 Deliberative Process (DP)

I am cc'ing Eben and Jason so they are in the loop.
Thanks,
Jim
--

James C. Kenney | Senior Policy Advisor for Oil and Gas
Office of Congressional and Intergovernmental Relations | Office of the Administrator | U.S. EPA
Desk/Mobile: (202) 768-2618 | *Email:* kenney.james@epa.gov

Please note: I am geographically located in Albuquerque, New Mexico (Mountain Time Zone).
This message may contain deliberative, attorney-client or otherwise privileged material. Do not release this message without the appropriate review. If you are not the intended recipient, kindly advise and delete this message/attachments. Namaste.

From: Lia Parisien <lparisien@ecos.org>
Sent: Wednesday, November 7, 2018 3:32 PM
To: Lia Parisien <lparisien@ecos.org>
Subject: Please Review by Dec. 3: Alternative Compliance Draft Paper

Advisory Group Members:

A few months ago we held a kickoff call to discuss plans for an Environmental Defense Fund/ECOS Shale Gas Caucus white paper on pathways for alternative compliance. The paper aims to assist state regulators in implementing oil and gas air rules that encourage innovation, and to help them act on applications for new methane reduction methodologies.

We've incorporated your suggestions and developed a draft paper for your review. Ahead of our next call on **December 3 at 3-4 p.m. Eastern**, please review the attached draft and be prepared to address the following questions::

- Are the lessons learned clear? Does the paper capture your understanding of the challenges of alternative compliance, or is there anything else to add?

- Are the recommendations compelling and comprehensive? Anything else to add?

- What roles would others need to play to carry out the recommendations? What new roles would be required of your agency?

- Are you familiar with any additional shared models that could inform the recommendation?

If you have questions or would like to share suggestions before the call, please email Aileen Nowlan of EDF at anowlan@edf.org and Lia Parisien of ECOS at lparisien@ecos.org.

Many thanks,

--

Lia Parisien
Executive Project Manager
Environmental Council of the States (ECOS)
(202) 266-4931
www.ecos.org
Mark your calendar for the April 8-10, 2019 ECOS Spring Meeting in Crystal City, VA!

--
Lia Parisien
Executive Project Manager
Environmental Council of the States (ECOS)
(202) 266-4931
www.ecos.org

Mark your calendar for the April 8-10, 2019 ECOS Spring Meeting in Crystal City, VA!

Message

From: Hambrick, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=787B0A3376944FCABAED4F018432CF44-AHAMBRIC]
Sent: 11/29/2018 7:24:42 PM
To: Hoffman, Howard [hoffman.howard@epa.gov]
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3
Attachments: OG Stakeholder Script 9.19.2018-KBedits (002).docx

Hi Howard- sorry for the delay in responding. This is what I am aware of as to what OAR has publicly said. I am not aware of any talking points related to the policy package used by OAR senior managers or Agency leadership, although I was told that AAW referenced the policy package in his keynote speech at the Shale Gas Caucus meeting in Pittsburgh in October.

1. Public Reg Agenda (Fall 2018)- https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201810&RIN=2060-AT90 (Note it was also in the Spring 2018 reg agenda)

EPA/OAR **RIN:** 2060-AT90 **Publication ID:** Fall 2018

Title: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review
Abstract:

On June 3, 2016, the Environmental Protection Agency (EPA) published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule." Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the rule. The EPA is addressing those specific reconsideration issues in a separate proposal. A number of states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance. On March 28, 2017, newly elected President Donald Trump issued Executive Order 13783 titled "Promoting Energy Independence and Economic Growth," which directs agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise or rescind regulations that unduly burden the development of U.S. energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. In 2017, the EPA provided notice to initiate the review of the 2016 rule and stated that, if appropriate, it will initiate proceedings to suspend, revise or rescind the rule. Subsequently, in a notice dated June 5, 2017, the EPA further committed to look broadly at the entire 2016 rule. The purpose of this action is to propose amendments to address key policy issues, such as the regulation of greenhouse gases, in this sector.

Agency: Environmental Protection Agency(EPA)
RIN Status: Previously published in the Unified Agenda
Major: No
EO 13771 Designation: Deregulatory
CFR Citation: 40 CFR 60
Legal Authority: 42 U.S.C. 7401 et seq., Clean Air Act

Priority: Other Significant
Agenda Stage of Rulemaking: Proposed Rule Stage
Unfunded Mandates: No

Legal Deadline: None
Statement of Need:

On June 3, 2016, the EPA published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule." On March 28, 2017, newly elected President Donald Trump issued Executive Order 13783 titled "Promoting Energy Independence and Economic Growth," which directs agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise or rescind regulations that unduly burden the development of U.S. energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. In 2017, the EPA provided notice to initiate the review of the 2016 rule and stated that, if appropriate, it will initiate proceedings to suspend, revise or rescind the rule. Subsequently, in a notice dated June 5, 2017, the

EPA further committed to look broadly at the entire 2016 rule. The purpose of this action is to propose amendments to address key policy issues, such as the regulation of greenhouse gases, in this sector. This proposal will solicit comments and/or information from the public regarding the Agency's proposed requirements and options under consideration. These amendments are anticipated to remove regulatory duplication in an effort to reduce burden.

Summary of the Legal Basis:

The review of the 2016 OOOOa rule is an exercise of the EPA's authority under section 111(b)(1)(B), section 307(d)(7)(B) and section 301(a) of the Clean Air Act.

Alternatives:

For the 2016 OOOOa review proposal, we anticipate soliciting comment on a lead policy option for the regulation of greenhouse gases and the sector regulatory structure and an alternative policy option under consideration.

Anticipated Costs and Benefits:

These values are estimates that are likely to change. Note all values at 7 percent discount rate in 2016 dollars. Total Present Value of Cost (2019 through 2025): $101 million Costs Annually: $18 million Forgone Benefits (2019 through 2025); $13 million Forgone Benefits Annually: $2.3 million

Risks:

We do not anticipate any risks to health related to this action.

Timetable:

Action	Date	FR Cite
NPRM	12/00/2018	
Final Rule	06/00/2019	

Additional Information: Docket #:EPA-HQ-OAR-2017-0757

Regulatory Flexibility Analysis Required: No

Small Entities Affected: No

Included in the Regulatory Plan: Yes

RIN Information URL: https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-oil-and-natural-gas-industry

Sectors Affected: 211111 Crude Petroleum and Natural Gas Extraction; 211112 Natural Gas Liquid Extraction; 221210 Natural Gas Distribution; 486110 Pipeline Transportation of Crude Oil; 486210 Pipeline Transportation of Natural Gas

RIN Data Printed in the FR: No

Government Levels Affected: None

Federalism: No

Agency Contact:
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2. As Derek referenced below, the reference in the technical reconsideration fact sheet:

- The Agency continues to consider broad policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and natural gas sector. These issues will be addressed in a separate proposal at a later date.

3. This is a talking point that was used in a stakeholder script: (full script is attached for you reference, note it is now out of date)

"The Agency continues to consider broad policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and natural gas sector. The agency will issue a separate proposal addressing those issues at a later date. "

Ex. 5 Deliberative Process (DP)

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Hoffman, Howard
Sent: Wednesday, November 28, 2018 1:07 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: Fw: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Amy -- we are looking for any information about the policy package that is already publicly available, which we'd like to use for an upcoming speech by the General Counsel, Matt Leopold. Pls see Derek Mills's e-mail immediately below. Mind if I ask if you are aware of anything else? Do you know if the policy package appears on any regulatory agendas for upcoming rules that are publicly available? Thx much.

From: Mills, Derek
Sent: Wednesday, November 28, 2018 12:12 PM
To: Marks, Matthew; Branning, Amy; Hoffman, Howard
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Howard,

On second thought, I was looking at the publicly-available fact sheet for the technical package and found the talking point below. Do you think that this is enough to say on the policy package? Would you recommend that Matt say more at this point? Thanks!

- The Agency continues to consider broad policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and natural gas sector. These issues will be addressed in a separate proposal at a later date.

Derek Mills

Attorney, Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-3341

From: Mills, Derek
Sent: Wednesday, November 28, 2018 11:47 AM
To: Marks, Matthew <Marks.Matthew@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Hoffman, Howard <hoffman.howard@epa.gov>
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Yes. I can work on this. **Howard**, do you want to draft a few short bullets for the policy package and send them to me? I can then send around a full draft to this group. Thanks!

Derek Mills
Attorney, Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-3341

From: Marks, Matthew
Sent: Wednesday, November 28, 2018 10:44 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>; Hoffman, Howard <hoffman.howard@epa.gov>
Subject: FW: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

FYI – Looks like we need to develop some O&G talking points for Matt by cob Monday. I'll let you know if we get more direction from Rob, but I think we should focus on the technical amendments for now and can add a few points on the upcoming policy package if necessary. Derek, given your time in the Front Office, I assume you are familiar with the level of detail Matt likes?

From: Zenick, Elliott
Sent: Wednesday, November 28, 2018 10:28 AM
To: Stachowiak, Robert <Stachowiak.Robert@epa.gov>; Srinivasan, Gautam <Srinivasan.Gautam@epa.gov>
Cc: Marks, Matthew <Marks.Matthew@epa.gov>
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Looping in Matt Marks since he will coordinate on (1). Please note that there are two oil and gas rules working their way through the system. The first is substantive revisions to the rule that reduce Leak Detection and Repair requirements. The second is one that would remove methane regulation. The second is on the unified agenda but is not public so there is not much that Matt can say at this time. Can you please confirm with him that it is the substantive revision package that he is looking for information on.

Here is the link to publicly available information:

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#regactions

Acting Deputy Associate General Counsel – ARLO
(202)564-1822

From: Stachowiak, Robert
Sent: Wednesday, November 28, 2018 10:14 AM
To: Srinivasan, Gautam <Srinivasan.Gautam@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Hi Gautam and Elliott -

Matt is giving a keynote address at an event hosted by the Rocky Mountain Mineral Law Foundation on Friday December 7. The audience is legal/non-legal professionals in the oil/gas and natural resources area, including industry, government, academics, and NGOs. Here is the session description:

> 8:10 am – 8:40 am
>
> **Keynote Presentation—Environmental Priorities for the Trump Administration**
>
> - Trump Administration's environmental priorities for oil, gas, and the natural resource industries
> - Where the Administration is currently focused, why it has made certain changes, and its plans going forward

Matt would like to address (1) the oil/gas methane rule; (2) the RFS rule to be issued on November 30, and (3) one other CAA topic relevant to the audience, that he requested you suggest. I'm preparing talking points for him, but I could really use your help, if at all possible no later than by COB Monday December 3.

Unfortunately, I don't seem to have inherited (or at least can't locate) existing talking points or background materials (e.g., press releases) on (1) or (2) in my files. So can you please suggest talking points for those issues, such as the basics, the current status, and if public, any future plans? (And also for (3), if it is a new issue.) He has 30 minutes to speak, and one other topic (CERCLA 108(b)) right now, so I expect a similar level of detail to the AAPCA talking points would be appropriate. If there is privileged material or other sensitive areas to be aware of, it is helpful to please identify it as such.

If you forward me on to other relevant folks in your office, please cc me and be explicit about from whom I should expect to receive the requested materials.

Thanks again for your help!

-Rob S.

Robert Stachowiak
U.S. Environmental Protection Agency
Acting Associate Deputy General Counsel
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Message

From: RTP-E-130-M@epa.gov [RTP-E-130-M@epa.gov]
Sent: 11/20/2018 8:24:14 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
Attachments: image2018-11-20-152414.pdf

Assessment of State-Level Fugitive Emissions Programs in Comparison to EPA NSPS

December 8, 2017

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This report addresses and responds to EPA's claims in its proposed rule and notice of data availability, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements, 82 Fed. Reg. 51788 (November 8, 2017) ("NODA") with regard to the relative efficacy of state-level fugitive emissions programs as compared to EPA's NSPS, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35824 (June 3, 2016) ("NSPS"). EPA claims that,

> While not all states have fugitive emissions programs, considering that many states with high oil and gas production do have such programs in place, it is not clear that the marginal additional emission reductions achieved during the EPA's reconsideration process outweigh the potential disruption to existing state programs and company-specific programs.[i]

EPA cites California, Colorado, North Dakota, Ohio, Pennsylvania, Texas, Utah, and Wyoming as states that have their own fugitive emissions programs.[ii]

EPA's suggestion that these states' LDAR programs render a stay of the national program insignificant is devoid of any analysis and misrepresents the emissions reductions achievable by each state's program, as it ignores many differences between the fugitive emissions programs in these states, including scope and coverage of facilities and segments, threshold emissions detection requirements, timeframe for repairing leaks, and other provisions of each program. Many of these state programs' fugitive emissions requirements are significantly less rigorous than EPA's NSPS, and thus achieve fewer benefits.

In the following tables, we have compared the scope and requirements of each state program. The data clearly indicates that many of these programs do not achieve the emissions reductions that the NSPS does within each state, respectively. The existence of these state programs does not support a stay of the NSPS. Moreover, the assessment below is conservative, as it does not account for other major oil and gas producing states that EPA did not cite, such as New Mexico and Montana, which do not have fugitive emission programs.

Exhibit 1 below illustrates the relative coverage of state LDAR programs as percentages of the wells covered under the NSPS. Combined, the states that EPA has identified as having fugitive emission programs that limit the NSPS's benefits cover only 34% of the wells covered by the NSPS. Moreover, even for the sources that are subject to some state programs, those programs vary in stringency and may not secure the same level of reductions as EPA standards. For instance, Pennsylvania provisions are not mandatory and only require annual inspections—far weaker than the NSPS standards.

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[i] 82 Fed. Reg. 51788, 51791.
[ii] *Id.*

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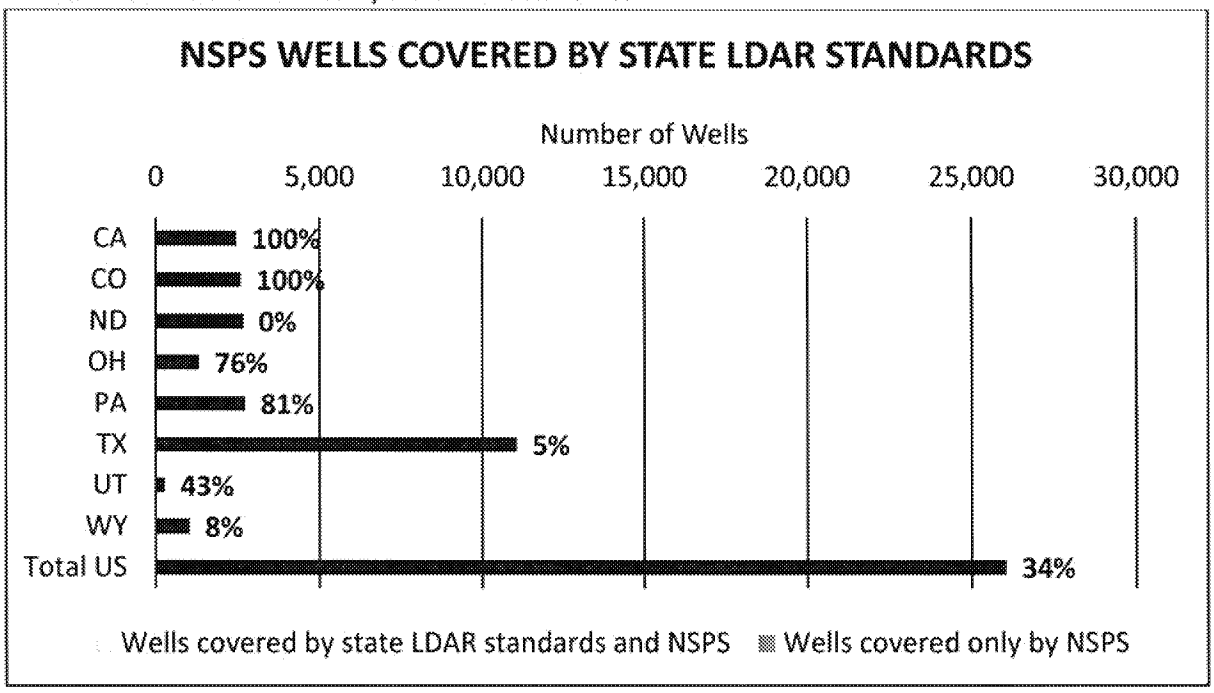
Exhibit 1. NSPS Wells Covered by State LDAR Standards



Major provisions indicating state programs attain insufficient emissions reductions to achieve parity with the NSPS include the following:

- One state cited by EPA, North Dakota, does not have a fugitive emissions program for well sites at all. North Dakota's fugitive emissions program covers only pipelines and underground storage facilities. Therefore **none** of the wells in North Dakota that are covered by the NSPS will be covered by a state standard during a stay of the NSPS.
- In Texas, the LDAR requirement only applies to wells with very high uncontrolled emissions (>10 or 25 tons per year (tpy), **an estimated 5%** of the NSPS covered wells (and as few as 0.5%). Because Texas has a very large number of additional wells that would be covered by the NSPS, the emissions reductions lost during an NSPS Stay would be substantial.
- Wyoming's fugitive emission program is specific to the state's ozone non-attainment area and thus is not state-wide. Furthermore, only wells within the nonattainment area with fugitive volatile organic compound (VOC) emissions above 4 tpy are covered. Therefore, **less than 10%** of the original covered wells would be covered by a state rule during a stay of the NSPS.
- Utah's program applies only to new sources, and does not cover the modified sources covered under the NSPS. Of those facilities, only sites with throughput equal to or greater than 10,000 barrels per year are covered by the standards, leaving out well over half of the wells covered by the NSPS.
- In Ohio, Utah, and Texas, provisions allow for inspection frequency to decrease based on the percentage of components leaking. This reduction in inspection frequency would decrease the inspection frequency below what the NSPS requires and would therefore lead to less emission reductions than the NSPS would achieve.
- In Colorado, inspection frequency at well sites depends on estimated tank emissions, with some categories requiring less frequent inspections than the semiannual inspections for well sites

required under the NSPS. Sources in these categories would be inspected less frequently and would therefore have fewer emissions reductions during a stay of the NSPS.

- In Pennsylvania, operators can choose to seek a permit exemption if their facility emits below specified levels and implements certain emission controls including conducting leak detection and repair. The provisions only require annual inspections, which will lead to fewer emission reductions than the semiannual inspections required by the NSPS, although proposed regulations may increase this frequency. Furthermore, only unconventional wells are covered, neglecting emissions from conventional wells.
- California has a higher emission threshold for repair than the NSPS, so leaks that necessitate repair under the NSPS may continue to emit under this state standard if the NSPS is stayed. In Texas, the emission threshold for repair for certain combinations of distance from sensitive receptors and potential to emit is higher than the NSPS.

The following tables compare each state program to the EPA NSPS for program aspects including supply chain segment and facilities covered, coverage of new and existing facilities, percentage of wells covered by each state program that are covered by the NSPS, thresholds before leak detection is required, threshold emission levels before repair is required, and frequency of surveys required.

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TABLE 1. SUPPLY CHAIN SEGMENT

EPA NSPS: WELL SITES, COMPRESSOR STATIONS, NATURAL GAS PROCESSING PLANTS[1]	
CA[2]	(1) ONSHORE & OFFSHORE CRUDE OIL OR NG PRODUCTION (2) CRUDE OIL, CONDENSATE, AND PRODUCED WATER SEPARATION AND STORAGE (3) NG UNDERGROUND STORAGE (4) NG GATHERING AND BOOSTING STATIONS (5) NG PROCESSING PLANTS (6) NG TRANSMISSION COMPRESSOR STATIONS
CO[3]	OIL AND GAS EXPLORATION AND PRODUCTION OPERATIONS, WELL PRODUCTION FACILITIES, NATURAL GAS COMPRESSOR STATIONS, AND NATURAL GAS PROCESSING PLANTS
ND[4]	UNDERGROUND GATHERING PIPELINES; UNDERGROUND CARBON DIOXIDE STORAGE FACILITIES; TREATING PLANTS; **NO WELL PRODUCTION SITES!**
OH[5]	UNCONVENTIONAL, HORIZONTAL, NON-TITLE V WELL SITES; GATHERING AND BOOSTING COMPRESSOR STATIONS
PA[6]	NATURAL GAS GATHERING AND BOOSTING STATIONS; UNCONVENTIONAL WELL SITES WHOSE OVERALL VOC EMISSIONS REMAIN BELOW 2.7 TPY; ADDITIONAL MEASURES **PROPOSED** FOR UNCONVENTIONAL WELL SITES, REMOTE PIGGING STATIONS, NG COMPRESSION STATIONS, PROCESSING PLANTS, AND TRANSMISSION STATIONS
TX[7]	(1) PETROLEUM REFINERIES; NATURAL GAS PROCESSING PLANTS IN OZONE NON-ATTAINMENT AREAS; (2) OIL AND GAS PRODUCTION AND PROCESSING SITES WITH THE POTENTIAL TO EMIT AT LEAST 10 OR 25 TPY OF UNCONTROLLED VOCS (DEPENDING ON DISTANCE FROM SENSITIVE RECEPTOR)
UT[8]	WELL SITES; TANK BATTERIES
WY[9]	OIL AND GAS EXPLORATION OR PRODUCTION WELL

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TABLE 2. SCOPE

EPA NSPS: NEW AND MODIFIED SOURCES (RELATIVE TO SEPTEMBER 18, 2015)	
CA[2]	NEW AND EXISTING
CO[3]	NEW AND EXISTING
ND[4]	NEW AND EXISTING
OH[5]	NEW AND MODIFIED (RELATIVE TO APRIL 4, 2014)
PA[6]	NEW AND MODIFIED (RELATIVE TO AUGUST 10, 2013)
TX[7]	NEW
UT[8]	NEW (RELATIVE TO JUNE 5, 2014)
WY[9]	NEW,MODIFIED, AND EXISTING SOURCES IN UPPER GREEN RIVER BASIN OR THE JONAH AND PINEDALE ANTICLINE DEVELOPMENT AREA AND NORMALLY PRESSURED LANCE

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TABLE 3. PERCENT COVERAGE BY STATE RULE OF WELL SITES THAT ARE COVERED BY 2016 NSPS RULE

WELLS COVERED BY NSPS: 26,013 WELLS

CA[2]	100%
CO[3]	100%
ND[4]	0%
OH[5]	76%
PA[6]	81%
TX[7]	UP TO 5% (OR AS LITTLE AS 0.5%)
UT[8]	43%
WY[9]	8%

Methodology for calculating the percent coverage by state rule of well sites covered by 2016 NSPS Rule

The original wells that would be covered by the NSPS were identified using data from DrillingInfo, a proprietary database that compiles a wide range of drilling- and production-related information from state oil and gas commissions. New and modified wells relative to September 18, 2015 are covered by the 2016 NSPS. New wells were identified as those with a spud date on or after September 18, 2015 and those with a missing spud date but with a first production date on or after September 18, 2015 (first production is reported by month so the formula conservatively uses October 1, 2015). Modified wells were selected as those with a completion date on or after September 18, 2015. Out of the set of 26,013 wells, the respective state regulations and permitting programs were applied to determine how many wells would still be covered by an LDAR program during a stay of the NSPS.

California and Colorado LDAR standards cover new and existing wells without any throughput or emission thresholds, so 100% of the NSPS wells in California and Colorado would be covered under state standards, if the NSPS were stayed.

North Dakota LDAR regulations do not apply to well sites, so 0% of the NSPS wells in North Dakota would still be covered.

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The Ohio permit requiring LDAR covers unconventional, horizontal, non-Title V well sites that are new and modified relative to April 4, 2014. This date is prior to the NSPS cut-off date, so no wells are excluded based on date. DrillingInfo does indicate whether a well is horizontal but does not indicate whether it is unconventional (for Ohio). Therefore, to be conservative, all horizontal wells in Ohio were assumed to be unconventional and therefore to qualify for the state permit requiring LDAR. The resulting 76% of NSPS wells covered under state standards is therefore an upper bound, as some horizontal wells may be conventional and would therefore not qualify for this permit (and thus for LDAR requirements).

Pennsylvania's current non-mandatory permit exemption program provides an exemption for operators who conduct leak detection and repair. The LDAR program covers unconventional well sites whose overall VOC emissions remain below 2.7 tpy that are new and modified relative to August 10, 2013. Again, this date is prior to the NSPS date, so no wells are excluded based on date. DrillingInfo does indicate in Pennsylvania whether a well is unconventional, so the original NSPS wells in Pennsylvania were filtered using this criteria. To be conservative, it was assumed that all unconventional wells in Pennsylvania have emissions below 2.7 tpy. This assumption is reasonable because many sources are excluded from contributing to the 2.7 tpy threshold (e.g., well drilling, completion and work-over activities and other sources meeting the exemption criteria). Our estimate that 81% of wells covered by the NSPS are included in Pennsylvania's program is likely an upper bound, both because it is a voluntary program, and because some unconventional wells may have higher emissions and would not qualify for this permit exemption.

Texas LDAR requirements only apply to wells required to apply for the Standard Permit, which is based on uncontrolled VOC emissions (>10 or 25 tpy) and distance from a sensitive receptor, such as a home or school. The 10 tpy VOC threshold was converted to a gas volume.[3] This is conservative, as it was assumed that the lower threshold was applicable rather than a combination of the lower and upper thresholds. The total affected NSPS wells were filtered to generate a list of new wells in Texas only. The annual gas production of each well was multiplied by 3% as an estimated leak rate per well. This leak rate is also conservative, as it represents the higher end of leak rates in the state.[4] The leak rate volumes for each well were compared to the threshold volume to estimate the number of new wells in Texas that would be subject to the state permit.[5]

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[3] Assumed a conversion ratio of 3.6 CH4/VOC, per EPA assumptions. Then applied the density of methane to the mass in order to find the methane volume. Assumed a 78.8% volume of methane in gas to convert to a gas volume.

[4] The 3% leak rate is conservatively high and results in a conservatively high estimate of covered wells. The leak rate in the Barnett Shale was found to be about 1.5% (ranging from 1.2% to 1.9%). Zavala-Araiza et al, *Reconciling divergent estimates of oil and gas methane emissions*, 2015, available at http://www.pnas.org/content/112/51/15597.full.pdf.

[5] We also utilized the Texas Commission on Environmental Quality (TCEQ) permit database for New Source Review Air Permits (http://www2.tceq.texas.gov/airperm/index.cfm?fuseaction=airpermits.start) to estimate wells in Texas subject to LDAR requirements under the Standard Permit. A search query was set up for Standard Permits for Oil and Gas Production Facilities with project completion dates after September 18, 2015 (the date at which the NSPS would apply to new and modified wells). The permit database does not consistently specify which permits are for wells and which are for

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Utah rules cover new wells relative to June 5, 2014 (again, this date is prior to the NSPS date). LDAR is only required for sources with "a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels." DrillingInfo does not provide a way to estimate projected throughput. Therefore, average annual throughput was used instead. Cumulative oil was divided by the number of months producing, and this average monthly throughput was multiplied by 12 in order to calculate average annual throughput. If this value was greater than 10,000 barrels, LDAR was assumed to apply to this well.

Wyoming rules apply to new, modified, and existing sources (relative to 2013) in the Upper Green River Basin (UGRB) or the Jonah and Pinedale Anticline Development Area and Normally Pressured Lance (JPAD/NPL) with fugitive emissions greater than or equal to 4 tpy of VOCs The NSPS wells in Wyoming were first filtered based on counties within the UGRB or the JPAD/NPL, yielding 503 wells. To determine how many of these wells would have fugitive emissions greater than or equal to 4 tpy, an analysis was completed of permits issued in the UGRB, which list fugitive emissions. Of a sample of 386 permits issued for the UGBR, 16% had fugitive emissions greater than or equal to 4 tpy VOC. This 16% was assumed to apply to the 503 wells out of the NSPS wells, leading to 80 wells covered by Wyoming LDAR rules, or 8% of the NSPS wells.

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other processing facilities such as gas plants or compressor stations. Some permits are specified as "well sites" while others are merely labeled as the standard permit. Given the constraints of the timeline for the comment period, we were unable to review each individual permit to determine if it applied to a well site. However, assuming all permits not specifying "well sites" were for compressor stations or processing plants, we concluded that the percentage of affected wells could be as low as 0.5%.

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TABLE 4. THRESHOLD FOR INSPECTION

EPA NSPS: NONE

CA[2]	NONE
CO[3]	NONE
ND[4]	NONE
OH[5]	NONE
PA[6]	NONE
TX[7]	PRODUCTION FACILITY: VOC EMISSIONS GREATER THAN 10 TPY OR 25 TPY, DEPENDING ON DISTANCE FROM SENSITIVE RECEPTOR
UT[8]	PROJECTED ANNUAL THROUGHPUT OF CRUDE OIL AND CONDENSATE COMBINED THAT IS GREATER THAN OR EQUAL TO 10,000 BARRELS.
WY[9]	FUGITIVE EMISSIONS ARE GREATER THAN OR EQUAL TO 4 TPY OF VOCS.

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TABLE 5. THRESHOLD FOR REPAIR

EPA NSPS: 500 PPM REPAIR THRESHOLD IF USING METHOD 21.	
CA[2]	1,000 PPM TOTAL HYDROCARBON LEAK THRESHOLD WHEN FULLY IMPLEMENTED.
CO[3]	500 PPM LEAK THRESHOLD (NEW) AND 2,000 PPM (EXISTING COMPRESSOR STATIONS), IF USE METHOD 21.
ND[4]	NONE
OH[5]	10,000 PPM FOR ALL COMPONENTS EXCEPT COMPRESSOR AND CLOSED VENT SYSTEM (500 PM), IF USE ANALYZER
PA[6]	2.5% METHANE USING A GAS LEAK DETECTOR AND A VOC CONCENTRATION OF 500 PPM
TX[7]	THRESHOLD FOR PRODUCTION FACILITY DEPENDS ON COMPONENT, DISTANCE FROM SENSITIVE RECEPTOR AND EMISSION THRESHOLD: 500 PPMV VOC, 2,000 PPMV OR 10,000 PPMV
UT[8]	500 PPM OR GREATER WITH AN ANALYZER OR A TUNED DIODE LASER ABSORPTION SPECTROSCOPY (TDLAS) ANALYZER.
WY[9]	NONE

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TABLE 6. FREQUENCY

EPA NSPS: INITIAL SURVEY WITHIN 60 DAYS OF STARTUP OR MODIFICATION SEMI-ANNUAL FOR WELL SITES; QUARTERLY INSPECTIONS FOR COMPRESSOR STATIONS	
CA[2]	QUARTERLY INSPECTION FREQUENCY DEPENDS ON ACTUAL FUGITIVE VOC TON PER YEAR EMISSIONS FOR COMPRESSOR STATIONS: COMPRESSOR STATIONS: 0-12: ANNUAL 13-50: QUARTERLY OVER 50: MONTHLY
CO[3]	INSPECTION FREQUENCY DEPENDS ON ACTUAL UNCONTROLLED VOC EMISSIONS FROM STORAGE TANKS OR FACILITY, IF NO TANKS, AT WELL SITES WELL SITES: 0-6: ONE-TIME 7-12: ANNUAL 13-50: QUARTERLY 50 AND ABOVE: MONTHLY MULTI-WELL SITES >20 WITHOUT TANKS: MONTHLY
ND[4]	N/A
OH[5]	INITIAL INSPECTION WITHIN 90 DAYS OF STARTUP; QUARTERLY INSPECTIONS FOR NEXT 4 QUARTERS; STEP DOWN TO SEMI-ANNUAL AFTER 4 CONSECUTIVE QUARTERS WITH NO MORE THAN 2% OF COMPONENTS LEAKING; STEP DOWN TO ANNUAL AFTER 2 CONSECUTIVE SEMI-ANNUAL INSPECTIONS IF NO MORE THAN 2% OF COMPONENTS LEAKING; STEP UP TO ORIGINAL QUARTERLY INSPECTIONS WHENEVER 2% OF MORE OF COMPONENTS ARE LEAKING
PA[6]	ANNUAL INSPECTION FOR UNCONVENTIONAL WELL SITES; QUARTERLY INSPECTIONS FOR G&B STATIONS
TX[7]	QUARTERLY WITH POSSIBILITY TO REDUCE TO SEMI-ANNUAL OR ANNUAL IF CERTAIN CONDITIONS ARE MET

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UT[8]	QUARTERLY INSPECTIONS FOR NEW WELL SITES/TANK BATTERIES WITH A PROJECTED ANNUAL CRUDE OIL OR CONDENSATE COMBINED THROUGHPUT OF >25,000 BARRELS. POTENTIAL TO REDUCE FREQUENCY TO SEMI-ANNUAL IF NO LEAKS DETECTED AFTER 1 YEAR AND TO ANNUAL IF NO LEAKS DETECTED FOR 2 YEARS. ANNUAL INSPECTIONS AT FACILITIES WITHOUT TANKS AND THOSE WITH LESS THAN 25,000 COMBINED ANNUAL CRUDE AND CONDENSATE THROUGHPUT.
WY[9]	QUARTERLY

References

1. EPA, Final NSPS Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, available at https://www3.epa.gov/airquality/oilandgas/may2016/nsps-finalrule.pdf.
2. 17 C.C.R. Section 95665 et seq (7-17-2017), available at https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I401BB8146DA14B519A991D7827913AEE&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)
3. Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, CO Reg. 7 § XVII, XVIII (Feb. 24, 2014).
4. North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, Rules and Regulations. Available at https://www.dmr.nd.gov/oilgas/rules/rulebook.pdf
5. Ohio EPA General Permit 12.1 and 12.2, available at http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx; Ohio GPs for compressor stations, available at http://epa.ohio.gov/dapc/genpermit/ngcs.aspx
6. PA GP-05, Natural Gas Compression Facilities, available at http://www.elibrary.dep.state.pa.us/dsweb/View/Collection-9747; Department of Environmental Protection, Air Quality Permit Exemption 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf; PA DEP Draft GP 5 and 5A available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-116054/2700-PM-BAQ0268_GP-5A.pdf and http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-116053/2700-PM-BAQ0267_GP-5%20.pdf
7. Texas Administrative Code Title 30, Part 1, Chapter 115, Subchapter D, Division 2 and 3; available at http://texreg.sos.state.tx.us/public/readtac%24ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=115&sch=D&div=3&rl=Y and http://texreg.sos.state.tx.us/public/readtac%24ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=115&sch=D&div=2&rl=Y

ED_002880A_00088516-00013

8. Utah GAO, available at https://deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf; U.A.C. §§ 307-501 to 307-504.
9. WDEQ, Oil and Gas Production Facilities Ch. 6, Section 2 Permitting Guidance for the UGRB (2016), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf; WDEQ, Air Quality Division Rules, Chapter 8, section 6 (May 19, 2015).

Message

From: Schiermeyer, Corry [schiermeyer.corry@epa.gov]
Sent: 8/30/2019 1:17:44 PM
To: Dickerson, Aaron [dickerson.aaron@epa.gov]
CC: Jackson, Ryan [jackson.ryan@epa.gov]; Idsal, Anne [idsal.anne@epa.gov]; Abboud, Michael [abboud.michael@epa.gov]; Beach, Christopher [beach.christopher@epa.gov]; Molina, Michael [molina.michael@epa.gov]
Subject: For AAW's binder
Attachments: FACTSHEET FINALOilandGas.pdf; OOOOa Talking Points 08.30.2019.docx

Hello Aaron,

The Administrator asked for talking points on the OOOOa/Methane announcement we had yesterday. Attached is a fact sheet and talking points.

Please put in his binder that goes to him tonight.

Thank you!!!

Corry Schiermeyer
Associate Administrator
Office of Public Affairs
Environmental Protection Agency
Schiermeyer.corry@epa.gov
202-564-6782

Message

From: DeLuca, Isabel [DeLuca.Isabel@epa.gov]
Sent: 4/24/2019 9:22:10 PM
To: Idsal, Anne [idsal.anne@epa.gov]; Woods, Clint [woods.clint@epa.gov]
CC: Millett, John [Millett.John@epa.gov]
Subject: draft NACAA presentation
Attachments: DRAFT Idsall NAACA 4.29.19 v1.docx

Hi Anne,
Attached are draft talkers for your NACAA presentation Monday. They have asked for a 30 minute presentation followed by 45 minutes of Q&A. It would be great to get your and Clint's input on areas to trim or develop. I expect Bill will have great feedback as well, when you think it is ready for his review.

In terms of prepping for Q&As, I'm hoping you and Clint can let me know what additional background docs you may need. I have a longer set of talkers on the Wood Stoves rule that I could share, and I can pull the public fact sheets on each proposed rulemaking, if those would be helpful. If you'd like more information, or tough Q&As on specific topics, let me know.

Ex. 6 Personal Privacy (PP)

Thanks,
Isabel

Isabel DeLuca
Office of Air and Radiation, US EPA
(202) 343-9247

Message

From: Woods, Clint [woods.clint@epa.gov]
Sent: 8/14/2019 5:50:41 PM
To: Idsal, Anne [idsal.anne@epa.gov]; DeLuca, Isabel [DeLuca.Isabel@epa.gov]; Schwab, Justin [Schwab.Justin@epa.gov]
Subject: Fwd: oil and gas package
Attachments: INTERNAL OG Policy Package.Comms Plan.DRAFT.V3.docx; ATT00001.htm

Latest version I have

Begin forwarded message:

> **From:** "DeLuca, Isabel" <DeLuca.Isabel@epa.gov>
> **Date:** August 5, 2019 at 4:34:12 PM EDT
> **To:** "Woods, Clint" <woods.clint@epa.gov>, "Dominguez, Alexander" <dominguez.alexander@epa.gov>
> **Subject: oil and gas package**
>
> Hi Clint & Alex,
> Attached is the latest comms plan for oil and gas, including the draft PR. We still have a plaeholder for the quote.
>
> There is one new paragraph (third from last) that mentions the technical package and timing for that.
>
> Thanks for taking a look,
> Isabel
>
> **Isabel DeLuca**
> Office of Air and Radiation, US EPA
> (202) 343-9247

Message

From: Schiermeyer, Corry [schiermeyer.corry@epa.gov]
Sent: 8/22/2019 2:27:22 PM
To: DeLuca, Isabel [DeLuca.Isabel@epa.gov]; McFaul, Jessica [mcfaul.jessica@epa.gov]; Beach, Christopher [beach.christopher@epa.gov]; Abboud, Michael [abboud.michael@epa.gov]; Idsal, Anne [idsal.anne@epa.gov]; Woods, Andrea [Woods.Andrea@epa.gov]; Woods, Clint [woods.clint@epa.gov]; Grantham, Nancy [Grantham.Nancy@epa.gov]
Subject: RE: oil and gas policy rule comms
Attachments: quad oa plan.docx

I made some updates to the rollout portion of this doc…

From: DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Sent: Tuesday, August 20, 2019 1:56 PM
To: Schiermeyer, Corry <schiermeyer.corry@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>; Beach, Christopher <beach.christopher@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; Grantham, Nancy <Grantham.Nancy@epa.gov>
Subject: oil and gas policy rule comms

Hi all,
I've added more detailed talkers on the oil and gas proposal below. Attached is a draft fact sheet, and the PR/comms plan again. OAQPS thinks we'll have final numbers on Thursday. (I've removed and highlighted the old #s so we don't inadvertently use the wrong ones.) I think it would be ok to share these for general awareness with the proviso that these are drafts and we will send final versions asap.

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

From: Schiermeyer, Corry <schiermeyer.corry@epa.gov>
Sent: Tuesday, August 20, 2019 11:54 AM
To: McFaul, Jessica <mcfaul.jessica@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Beach, Christopher <beach.christopher@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>
Subject: RE: For tomorrow

Let's see if we have some more talking points…I have:

Ex. 5 Deliberative Process (DP)

From: McFaul, Jessica <mcfaul.jessica@epa.gov>
Sent: Tuesday, August 20, 2019 11:49 AM
To: DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Beach, Christopher <beach.christopher@epa.gov>; Schiermeyer, Corry <schiermeyer.corry@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>
Subject: RE: For tomorrow

Recognizing this is draft and subject to change, can this be shared with Regions 3, 6 and 8 to help them develop their press plans? Jess

From: DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Sent: Tuesday, August 20, 2019 9:16 AM
To: Beach, Christopher <beach.christopher@epa.gov>; Schiermeyer, Corry <schiermeyer.corry@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>
Subject: RE: For tomorrow

Thanks, Chris! Resending the comms plan with quote included. FYI, we may have some slight revisions to this plan coming soon to reflect changes coming out of OMB review. I'll recirculate when I get those edits.

From: Beach, Christopher <beach.christopher@epa.gov>
Sent: Tuesday, August 20, 2019 9:06 AM
To: Schiermeyer, Corry <schiermeyer.corry@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>
Subject: RE: For tomorrow

Here's the approved quote I sent around last week. This is good to go.

Ex. 5 Deliberative Process (DP)

-----Original Message-----
From: Schiermeyer, Corry <schiermeyer.corry@epa.gov>
Sent: Tuesday, August 20, 2019 9:00 AM
To: DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>
Cc: Beach, Christopher <beach.christopher@epa.gov>
Subject: RE: For tomorrow

Adding Chris Beach for an Administrator quote.

Please note, I am working on having the WSJ talk to Anne tomorrow on background, then follow up with an on the record when we are ready to announce.

Thank you

-----Original Message-----
From: DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Sent: Tuesday, August 20, 2019 8:58 AM
To: Schiermeyer, Corry <schiermeyer.corry@epa.gov>; Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>
Subject: RE: For tomorrow

Attached is the latest comms plan & PR. I'll send the fact sheet asap -- OAQPS was holding to incorporate edits made during OMB discussions. You'll note the PR does not have a quote -- let me know if you'd like us to take the first crack.

Thanks,
Isabel

-----Original Message-----
From: Schiermeyer, Corry <schiermeyer.corry@epa.gov>
Sent: Tuesday, August 20, 2019 8:21 AM
To: Abboud, Michael <abboud.michael@epa.gov>; Idsal, Anne <idsal.anne@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>

Cc: DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Subject: RE: For tomorrow

Adding Isabel...do you have the updated factsheet that we discussed last week on the call?

Thank you!

-----Original Message-----
From: Abboud, Michael <abboud.michael@epa.gov>
Sent: Tuesday, August 20, 2019 12:26 AM
To: Idsal, Anne <idsal.anne@epa.gov>; Schiermeyer, Corry <schiermeyer.corry@epa.gov>; Woods, Andrea <Woods.Andrea@epa.gov>; Woods, Clint <woods.clint@epa.gov>; McFaul, Jessica <mcfaul.jessica@epa.gov>
Subject: For tomorrow

I'm not sure if the methane factsheets have changed since the Isabel sent them around. But can you send over the latest one for Wheeler to see?

Sent from my iPhone

Message

From: Jackson, Ryan [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=38BC8E18791A47D88A279DB2FEC8BD60-JACKSON, RY]
Sent: 2/26/2018 6:44:01 PM
To: Bowman, Liz [Bowman.Liz@epa.gov]
Subject: FW: For Review: Draft Oil Gas Actions Release

Do you have what you need to announce both of these when most appropriate?

From: Wehrum, Bill
Sent: Friday, February 23, 2018 6:46 PM
To: Bowman, Liz <Bowman.Liz@epa.gov>
Cc: Jackson, Ryan <jackson.ryan@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Woods, Clint <woods.clint@epa.gov>; Harlow, David <harlow.david@epa.gov>; Block, Molly <block.molly@epa.gov>; Daniell, Kelsi <daniell.kelsi@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Re: For Review: Draft Oil Gas Actions Release

Should be ready to sign early next week.

_____

Bill Wehrum

Assistant Administrator

Office of Air and Radiation

U.S. Environmental Protection Agency

(202) 564-7404

On Feb 23, 2018, at 6:44 PM, Bowman, Liz <Bowman.Liz@epa.gov> wrote:

> Oh yeah I was going to wait until that was signed. But if it won't be for a few weeks, we can separate the releases
>
> On Feb 23, 2018, at 6:28 PM, Wehrum, Bill <Wehrum.Bill@epa.gov> wrote:
>
> > This looks fine. But, I do not think the CTG proposal has been signed yet. Announcing that proposal at this time would be a bit premature.
> >
> > _____
> >
> > Bill Wehrum
> >
> > Assistant Administrator
> >
> > Office of Air and Radiation
> >
> > U.S. Environmental Protection Agency
> >
> > (202) 564-7404

On Feb 23, 2018, at 6:25 PM, Jackson, Ryan <jackson.ryan@epa.gov> wrote:

If OAR is ok I am.

Ryan Jackson

Chief of Staff

U.S. EPA

202-564-6999

On Feb 23, 2018, at 5:34 PM, Bowman, Liz <Bowman.Liz@epa.gov> wrote:

Attached, and below, please find a draft release on the oil and gas issues. I think we should put this out once both are signed, but we can separate it into two, if you want the amendments one to go out first thing Monday. Thank you – Liz

EPA TAKES ACTION TO ADDRESS OIL AND GAS COMPLIANCE CONCERNS

EPA Proposes to Withdraw the Control Techniques Guidelines and Finalizes Amendments to NSPS for the Oil and Natural Gas Industry

WASHINGTON - In two actions, EPA is taking steps that address significant and immediate compliance concerns for the oil and natural gas industry that will reduce burden to our state regulatory partners.

EPA has finalized amendments of certain requirements contained within the 2016 Oil and Gas New Source Performance Standard (NSPS) and proposed to withdraw the control techniques guidelines.

"The technical amendments to the 2016 oil and gas NSPS are meant to alleviate targeted regulatory compliance issues faced by affected sources," **Assistant Administrator for EPA's Office of Air and Radiation Bill Wehrum.** "While this action addresses an immediate

need, it does not deter the ongoing work at the Agency to assess the 2016 rule as a whole, including whether it is prudent or necessary to directly regulate methane."

Amendments to the 2016 New Source Performance Standards for the Oil and Gas Industry

EPA has amended two narrow provisions of the 2016 New Source Performance Standards (NSPS) for the oil and natural gas industry to address aspects of the rule that pose significant and immediate compliance concerns. The amendments address two of the "fugitive emissions" requirements in the 2016 rule: a requirement that leaking components be repaired during unplanned or emergency shutdowns; and the monitoring survey requirements for well sites located on the Alaskan North Slope.

EPA took this final action in response to comments received on the June 2017 proposed stays of certain requirements in the rule and subsequent Notices of Data Availability (NODAs), which were issued in November 2017. EPA is continuing to evaluate the comments the agency received on the proposed stays and NODAs.

To read the amendments to the 2016 rule, visit EPA's website at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#regactions

Proposal to withdraw the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry

In a separate action, EPA is proposing to withdraw the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry (Oil and Gas CTG) in its entirety. The Oil and Gas CTG provides recommendations for certain states and areas that are required to address smog-forming volatile organic compound (VOC) emissions from covered sources as part of their state implementation plans for meeting EPA's national standards for ground-level ozone.

The Oil and Gas CTG relied on data and conclusions that were used in the 2016 New Source Performance Standards (NSPS) for the oil and gas industry. EPA is currently reconsidering certain aspects of the 2016 NSPS and intends to look broadly at the rule during the reconsideration process.

Because some recommendations in the Oil and Gas CTG are based on the 2016 NSPS, and others are based on the NSPS issued in 2012, EPA believes withdrawing the entire Oil and Gas CTG will be more efficient for states, which otherwise might be required to revise their implementation plans twice: once, to address recommendations that are tied to the 2012 NSPS, and potentially a second time after the reconsideration of the 2016 NSPS is complete.

The agency will take public comment on withdrawing the Oil and Gas CTG for 45 days after a notice is published in the Federal Register.

To read the notice of proposed withdrawal, visit EPA's website at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#ctg

<2018-02-23 Draft Oil Gas Actions Release.docx>

Message

From: Witosky, Matthew [Witosky.Matthew@epa.gov]
Sent: 4/20/2017 4:16:18 PM
To: Miller, Elizabeth [Miller.Elizabeth@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]; Lamson, Amy [Lamson.Amy@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]
CC: Macpherson, Alex [Macpherson.Alex@epa.gov]; Cozzie, David [Cozzie.David@epa.gov]
Subject: RE: Oil and Gas research

It's ok as such articles go. It does a nice job of explaining the variables you will find when approaching the problem. They miss some of the nuance in the *final rule* (the term they use for OOOOa) and then project new policy on the issue they overlook (distance of observation from the leak, wind speed, for example).

The also get into the fat tail distribution of leaks, which we are approaching in the RFI powerpoint on detection - that monitoring systems spend a lot of time and expense looking for super-emitters at a well site and finding them infrequently, instead of looking for them across a section or basin.

Ex. 5 Deliberative Process (DP)

Thanks for sending it around,

Matthew

From: Miller, Elizabeth
Sent: Thursday, April 20, 2017 9:34 AM
To: Thompson, Lisa ; Lamson, Amy ; Marsh, Karen ; Witosky, Matthew
Cc: Macpherson, Alex
Subject: Oil and Gas research

Hi everyone,
Alex found an article regarding the ONG NSPS that indicates our cost estimates are over estimated (by about 27%) and the emission reductions are overestimated (by about 20% - 50%).

Here is the abstract:

Abstract

Methane-a short-lived and potent greenhouse gas-presents a unique challenge: it is emitted from a large number of highly distributed and diffuse sources. In this regard, the United States' Environmental Protection Agency (EPA) has recommended periodic leak detection and repair surveys at oil and gas facilities using optical gas imaging technology. This regulation requires an operator to fix all detected leaks within a set time period. Whether such 'find-all-fix-all' policies are effective depends on significant uncertainties in the character of emissions. In this work, we systematically analyze the effect of facility-related and mitigation-related uncertainties on regulation effectiveness. Drawing from multiple publicly-available datasets, we find that: (1) highly-skewed leak-size distributions strongly influence emissions reduction potential; (2) variations in emissions estimates across facilities leads to large variability in mitigation effectiveness; (3) emissions reductions from optical gas imaging-based leak detection programs can range from 15% to over 70%; and (4)

while implementation costs are uniformly lower than EPA estimates, benefits from saved gas are highly variable. Combining empirical evidence with model results, we propose four policy options for effective methane mitigation: performance-oriented targets for accelerated emission reductions, flexible policy mechanisms to account for regional variation, technology-agnostic regulations to encourage adoption of the most cost-effective measures, and coordination with other greenhouse gas mitigation policies to reduce unintended spillover effects.

The article discussing the research paper can be found here: http://news.stanford.edu/2017/04/18/epa-methane-emission-policy-likely-cost-less-miss-2025-targets-stanford-researchers-find/

The actual research paper can be found here: http://iopscience.iop.org/article/10.1088/1748-9326/aa6791

If you have any questions, let us know!
Thanks,
Beth

Elizabeth (Beth) Miller, Ph.D.
Economist, Air Economics Group
HEID, OAQPS, Office of Air and Radiation
U.S. Environmental Protection Agency
Phone: 919-541-2054
Please note my email address: Miller.Elizabeth@epa.gov
(If you send it to 'Beth', I will not receive it)

Message

From: Ryan Steadley [steadley@strongerinc.org]
Sent: 2/26/2019 10:16:35 PM
To: rrouth@cleanair.org; David McCabe [dmccabe@catf.us]; Greg Johnston [greg.johnston@chk.com]; mdearing@enervest.net; Jarrett, James F [James.F.Jarrett@wv.gov]; Alkadi, Nasr (BHGE) [Nasr.Alkadi@bhge.com]; Tony St Clair [tstclair@hess.com]; Pratt, Karen [Karen_Pratt@xtoenergy.com]; Ryan, Vanessa A [Vanessa.Ryan@chevron.com]; Penny Seipel [penny@ooga.org]; Grover Campbell [Grover.Campbell@dvn.com]; Garvey, Megan [garvey.megan@epa.gov]; SubraCom@aol.com; Marsh, Karen [Marsh.Karen@epa.gov]; elizabeth paranhos [elizabethparanhos@delonelaw.com]; leah.martland@state.co.us
Subject: Re: STRONGER Air Quality Guidelines Workgroup
Attachments: STRONGER Air Guidelines Earthworks comments.pdf

All,

Apologies, I missed one comment document in my earlier message. Please see the attached.

Ryan Steadley
Executive Director
STRONGER
405.249.6131

On Feb 26, 2019, at 12:02 PM, Ryan Steadley <steadley@strongerinc.org> wrote:

All,

Here are the consolidated comments received on the air quality guidelines. The majority of the substantive comments on the content came from EPA and Boulder County Public Health Dept. Please review in advance of our call next Friday. We will need to finish the draft on this call.

Thank you,

Ryan Steadley
Executive Director
STRONGER
405.249.6131

<All Comments - STR AQG Update.docx>

On Feb 20, 2019, at 10:51 AM, Ryan Steadley <steadley@strongerinc.org> wrote:

Hi All,

We will hold our comment review call on March 8 at 10am central. The call-in number is 405-548-5148, no PIN is required.

AQ Guidelines Comment Review
Scheduled: Mar 8, 2019 at 10:00 AM to 11:30 AM
Location: 405-548-5148

<iCal-20190220-104846.ics>

Best,

Ryan Steadley
Executive Director
STRONGER
405.249.6131

On Jan 31, 2019, at 4:17 PM, Ryan Steadley <steadley@strongerinc.org> wrote:

Hi All,

As you know, the draft air quality guidelines have been out for a public comment period that was scheduled to end tomorrow. Now that the government is back open, EPA has requested an extension of the comment period until February 22. We will leave the draft open for comments from all stakeholders until that time. Here is a poll to schedule a call during the week of March 4 to review the comments, make any revisions, and approve the final draft for the Board:

https://doodle.com/poll/6iwh48dg6yum5zi7

I will send out a draft with all of the comments received in advance. Thanks for your patience and continuing participation on this effort.

Have a great weekend,

Ryan Steadley
Executive Director
STRONGER
405.249.6131

On Nov 26, 2018, at 12:41 PM, Ryan Steadley <steadley@strongerinc.org> wrote:

Hi All,

I hope you enjoyed a wonderful Thanksgiving holiday. The latest version of the draft is attached with edits from our previous call. Based on our discussion last time I think we are close to tying this up. Our next call will be on **Tuesday, December 4**

at 10:00am central time. Look forward to talking with you then.

AQ Workgroup Call 3
Scheduled: Dec 4, 2018 at 10:00 AM to 11:30 AM
Location: 405-548-5148
<iCal-20181126-124001.ics>

Ryan Steadley
Executive Director
STRONGER
405.249.6131

<STRONGER Air Quality Guidelines - 2018 Update Draft - 12-4-18.docx>

> On Nov 7, 2018, at 3:38 PM, Ryan Steadley <steadley@strongerinc.org> wrote:
>
> Thanks to all who were able to join the call this afternoon, good progress. The draft with today's changes is attached. Here is a poll to schedule our next call for the week of December 3-7: https://doodle.com/poll/vw87rk4m4kx7yuzb.
>
> Editors, if you could please send me your revisions by November 27 that would be great.
>
> Ryan Steadley
> Executive Director
> STRONGER
> 405.249.6131
>
> <STRONGER Air Quality Guidelines - 2018 Update Draft - 11-7-18.docx>
>
> > On Oct 31, 2018, at 6:13 PM, Ryan Steadley <steadley@strongerinc.org> wrote:
> >
> > Happy Halloween,

Apologies for the delay on getting this out. Our next call will be Wednesday, November 7 from 2-3:30pm central. The conference number is 405-548-5148, no PIN is required to join. Attached is an updated draft with Grover and Greg's edits as well as Leah's comments.

Look forward to talking with you then.

Ryan Steadley
Executive Director
STRONGER
405.249.6131

<STRONGER Air Quality Guidelines - 2018 Update Draft - 10-31-18.docx>

On Oct 26, 2018, at 9:43 AM, Ryan Steadley <steadley@strongerinc.org> wrote:

Greetings All,

I'll be choosing the time for our next

conference call in the week of November 5 on Tuesday, October 30. If you have not already indicated your availability on the poll, please do so: https://doodle.com/poll/a9eszp6n7vqm77gp. I'll also be sending out an updated draft for the call with Grover and Greg's edits and Leah's comments. Since

not everyone can access the Google drive/docs, we'll work from a word doc from here on out.

Thanks and have a great weekend,

Ryan Steadley
Executive Director
STRONGER
405.249.6131

EARTHWORKS

February 1, 2019

Dear STRONGER,

Thank you for the opportunity to provide comment on STRONGER's Air Quality Guidelines (AQG) to control emissions from oil and gas activities. Please accept these comments on behalf of Earthworks. We are a nonprofit organization dedicated to protecting communities and the environment, while seeking a just transition toward renewable energy.

General Comments

Earthworks especially appreciates three aspects of the AQG's general approach. First, they recommend states implement the Environmental Protection Agency (EPA)'s 2016 methane rule (40 CFR Part 60, Subpart OOOOa or "methane rule"). The AQGs also recognize the methane rule's limitations, especially as it applies to state-specific needs.

For this reason, we also commend STRONGER for emphasizing how each federal Clean Air Act regime provides the regulatory floor upon which states build a suitably tailored oil and gas air program (i.e., Title V (major sources), National Ambient Air Quality Standards (NAAQS), New Source Performance Standards (NSPS), etc.). To accomplish this, the public, agencies, and regulated community should have the best understanding of which sources pollute the most.

Updates to state emissions inventories, systems, and recordkeeping (10.3.1 and 10.3.4) provide a good place to start. Improving the data and systems will require better air monitoring (10.3.3) to provide a more sound scientific baseline for states to enact source-specific requirements (10.3.2). States must also devote the resources needed to enforce their updated air program requirements (10.2.4-10.2.7).

Finally, throughout the AQG's proposal, STRONGER creates a strong presumption favoring public participation. This is crucial. Earthworks supports the formation of multistakeholder Advisory Groups (10.2.8 and 4.2.2.3) as a forum to resolve air quality concerns and provide accountability to government and industry.

Specific Comments

10.2.1 Scope of Authority

The AQG should explicitly counsel states against preempting municipalities from ordinances protecting the health, safety, and welfare of their own residents. This guideline should provide that, in no case, shall an ordinance weaken state protections.

10.2.2 Jurisdiction and Cooperation Between Agencies

We appreciate AQG's recommendation that agencies communicate with the regulated community and the public. The blend of state, federal, and tribal agencies with responsibility for air emissions from oil and gas facilities can create confusion for communities facing pollution. Earthworks agrees that Memoranda of Understanding (MOUs), the creation of Advisory Groups, task forces, and joint facility inspections with all stakeholders, including the public, may help facilitate better coordination.

Dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions.

1612 K St. NW, Suite 904
Washington, DC 20006
202.887.1872
EARTHWORKS.ORG

earthworksaction
@earthworks

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10.2.3 Permits, Authorizations and Exemptions

As the AQG notes, the Clean Air Act prohibits the construction of a major source without a permit. Earthworks has documented problems in Pennsylvania and Texas where unscrupulous operators deliberately manipulated the permit process to avoid Title V classification. They did so primarily through seeking "minor" permits for frequent expansions in a piecemeal fashion, while artificially revising emissions estimates downward so to appear to remain under Title V thresholds. (See Earthworks' 2017 report *Permitted to Pollute*, https://earthworks.org/publications/permitted_to_pollute/.

Generally, applicants face few hurdles in receiving the necessary permits and authorizations. The main deficiency in state air programs comes in enforcement (discussed below), not in processing permit applications. Speeding up the permit process will neither result in better agency decisions nor in more effective environmental and public health outcomes. We oppose mechanisms that facilitate faster permitting including permit exemptions and permits by rule.

We applaud the AQG for encouraging states to consider federal rules (i.e., the methane rule) and pushing states to adopt additional air quality requirements beyond federal requirements to address their own needs.

10.2.4 Compliance Monitoring, Demonstration & Assurance

Earthworks agrees that states need clear legal authorities to investigate, fine, and take other enforcement actions. Relatedly, states should improve records retention systems and make records available on a publicly accessible website or upon request.

This AQG should advise states to presume all records are public. Operators seeking protection for purported trade secrets or confidential business information (CBI) must take appropriate steps to safeguard the information and demonstrate that its disclosure would substantially harm their business interests.

We commend the AQG proposal to encourage state inspection and monitoring information and procedures independent of the regulated community. This may help deter some facility operators from ducking Title V designation. It will also allow the state to determine additional program requirements, conduct inspections, target investigations, and assist compliance.

In some cases, states may create appropriate incentives to quickly correct violations. As discussed below, independent inspections by qualified third-parties can catalyze faster repairs resulting in better compliance, efficiency, and public health outcomes. States should not rely upon voluntary measures, industry pledges, and self-reporting mechanisms as evidence of reduced emissions or regulatory compliance.

10.2.5 Enforcement

We agree states should have effective enforcement tools to punish and deter violations of state air programs. Tools should include efficient methods for seeking fines, penalties, and administrative orders including permit revocation. States must first act as a backstop for protecting air quality, through regulation, inspection, and enforcement. And yet policymakers have long recognized that not all wisdom resides within agency bureaucracies and state Capitols. For this reason, states should supplement their own enforcement by empowering the public in two ways.

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First, we support the right to judicial review of state action, from any aggrieved party with standing (10.2.5.3). States should ensure their law and regulations contain standard citizen suit provisions, like those of the Clean Air Act (42 USC 7604), opening the courthouse doors to the public harmed by oil and gas air pollution. Second, state agencies should create Advisory Groups (4.2.2.3) for citizen science, especially independent verification of Leak Detection and Repair (LDAR) compliance.

Optical Gas Imaging (OGI) technology has become a standard part of accepted LDAR procedures. In many states, regulatory agencies hire, train, equip, and certify inspectors to perform OGI, other LDAR, or other inspection methods. More states now require operators, or their agents, to perform periodic LDAR inspections as well. To reduce the burden on agencies and the regulated community, states may complement required LDAR inspections with independent verification.

States, just as operators, may partner with third parties such as private consultants, academic institutions, and non-governmental organizations to detect and report emissions leaks. States can require independent verifiers to use the same or similar state-approved leak detection methods (i.e., OGI or EPA Method 21). Independent inspections may provide valuable assistance to regulators and operators by revealing leaks most in need of repair.

This would allow states and operators to focus inspection enforcement resources more efficiently. Prioritizing repairs based upon known leaks would reduce emissions, save money, and lower the compliance burden. As an incentive, an operator can satisfy a periodic LDAR inspection requirement by certifying to the state that they fixed the leak detected from the independent inspection during the same period.

10.2.6 Staffing and Training and 10.2.7 Data Management

Earthworks agrees that an effective state air program must have adequate staffing, training, and data systems.

10.2.8 Public Involvement

We support this AQG's recommendation for public involvement in accordance with STRONGER's guidelines in Sections 4.2.2.2 and 4.2.2.3. In particular, we support states creating Advisory Groups for the public and the regulated community to weigh the effectiveness of state regulation, inspection, and enforcement.

The Advisory Groups could help resolve community complaints, promote effective compliance, and establish a social license to operate. The panels could similarly serve as a forum for prioritizing repairs of leaks, adapting emissions inventories (in Sec. 10.3.4), and drive changes in operational practices.

This AQG should also encourage states to grant public hearings upon request.

10.3.1 Delineation of Sources

We support this AQG recommendation for states to inventory all their air emissions sources. States should make these inventories available upon request and on a publicly accessible website.

In particular, we appreciate the importance the AQG places upon counting emissions from grandfathered and other existing facilities that sometimes avoid inventory reporting. Many oil and gas

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states have old or abandoned conventional wells and infrastructure that leak significant amounts of methane and volatile organic compounds.

10.3.2 Source-Specific Requirements

Most states should control air emissions across the entire oil and natural gas chain by carefully considering together the methane rule and EPA's 2016 Control Technique Guidelines for the Oil and Gas Industry (CTGs). The AQG's approach properly considers federal requirements as a floor, with an eye toward source-specific requirements that target state's individual emissions reduction needs. This frees states to implement at least three kinds of more stringent protections.

First, state protections should apply broadly to all existing air emissions sources--without exception, including conventional oil and gas production, old, abandoned, and grandfathered facilities. Second, states should regulate methane directly. Third, states must apply protections to all sectors of their oil and gas industry, including downstream from processing and transmission.

As the oil and gas industry continues to expand, an effective state air program will identify each oil and gas emissions source type within its borders. This will help agencies determine the accuracy of Potential to Emit (PTE) estimates from permit applicants. States should strictly scrutinize permit applications from expanding facilities in nonattainment areas or teetering on the edge of Title V thresholds.

We also support state provisions designed to quantify and minimize waste from venting and flaring.

10.3.3 Air Quality Monitoring Networks

States should expand their ambient air quality monitoring networks to include monitors close to oil and gas sources, which often occurs in rural areas. Doing so is critical for determining the additive air quality impact of new drilling and infrastructure, and in turn states' attainment status for ozone and other pollutants. Again, this AQG correctly recognizes many states should impose monitoring standards that go beyond those of federal law. As these AQG's note:

Areas with significant oil and gas production activity may have few or no regulatory air quality monitors, because these areas may not meet typical criteria for siting of monitors, such as population density.

10.3.4 Reporting, Emission Inventories & Recordkeeping

We support states conducting periodic reviews of their emissions inventories in order to help the public and the regulated community adjust to changes in production or operational practices.

10.3.6 Long-Term Planning, Prioritization & Evaluation

Interested stakeholders (including environmental and community groups) should participate in periodic planning and analyses to ensure that air quality programs remain protective of public health and the environment. We agree with STRONGER this is especially true as states with oil and gas exploration, production, or infrastructure periodically update their NAAQS, State Implementation Plans (SIPs), Title V, and other Clean Air Act delegated programs.

However, streamlined permitting programs and permits by rule do not remain the most protective. Voluntary measures, industry driven pledges, and market-based incentives can never substitute for effective regulation and enforcement.

Conclusion

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Overall, these AQGs point state air programs in the right direction. These guidelines acknowledge that the baseline regulatory standard begins with adoption and implementation of federal rules, include EPA's methane rule. States should also inventory their oil and gas emissions sources while they hire, train, and equip more enforcement officials. With updated systems, staffing, and emissions data, the state can use sound science and community input to develop air programs more protective of public health and the environment.

Finally, we appreciate the opportunity to provide our comments on these AQGs. Most importantly, these guidelines repeatedly elevate the importance and role of considering public comment in air program decisions. Thank you for your consideration.

Sincerely,

Aaron Mintzes

Senior Policy Counsel, Earthworks

Dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions.

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Message

From: Marsh, Karen [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=03408BEA5D5B4030BE80FA390ED47026-MARSH, KARE]
Sent: 11/19/2018 5:10:30 PM
To: Colon, Toni [Colon.Toni@epa.gov]
Subject: Presentation for today
Attachments: OG NTAA Call 11.19.18.pptx

Toni,

Here's the presentation I plan to use today.

Karen

****
Karen R. Marsh, PE
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United States Environmental Protection Agency

Oil and Natural Gas : 2016 New Source Performance Standards (OOOOa)

Informational Meeting with Tribes

November 19, 2018

Overview

- Oil and Gas Industry
- Timeline of Actions
- 2016 New Source Performance Standards (NSPS)
- 2018 Proposed Amendments
- Resources

Oil and Gas Industry

Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines

Production & Processing

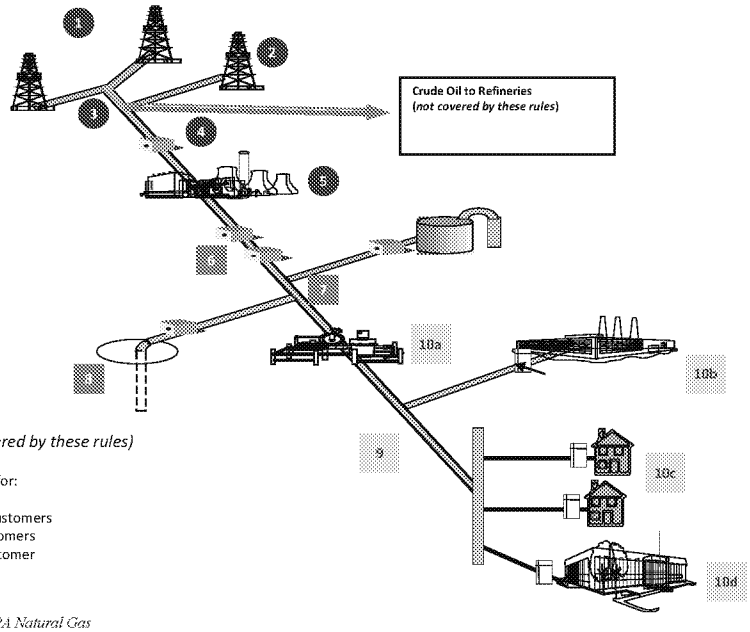
1. Drilling and Well Completion
2. Producing Wells
3. Gathering Lines
4. Gathering and Boosting Compressors
5. Gas Processing Plant

Natural Gas Transmission & Storage

6. Transmission Compressor Stations
7. Transmission Pipeline
8. Underground Storage

Distribution *(not covered by these rules)*

9. Distribution Mains
10. Regulators and Meters for:
    a. City Gate
    b. Large Volume Customers
    c. Residential Customers
    d. Commercial Customer



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

OAQPS Rules: NSPS

- **September 2012:** EPA issued New Source Performance Standards (NSPS) for oil and gas industry, commonly referred to as NSPS OOOO
- **June 2016:** EPA issued additional NSPS for oil and gas industry, commonly referred to as NSPS OOOOa
  - **April 2017:** EPA granted reconsideration of fugitive emissions requirements
- **June 2017:** EPA announced reconsideration on two additional requirements:
  - Well site pneumatic pumps standards; and
  - Professional engineer certification requirements for the design capacity of closed vent systems
- **March 2018:** EPA amended two narrow provisions of 2016 NSPS to address two fugitive emissions requirements:
  - Requirement that leaking components be repaired during unplanned or emergency shutdowns
  - Monitoring survey requirements for well sites located on Alaskan North Slope

OAQPS Rules: NSPS (cont.)

- **October 2018:** EPA proposed amendments and clarifications related to the specific reconsideration issues identified in 2017
  - Streamline implementation
  - Reduce duplicative EPA and state requirements
  - Significantly decrease unnecessary burdens on domestic energy producers
  - EPA will continue to consider broad policy issues in 2016 rule, including regulation of GHG in sector; issues will be addressed in separate proposal at a later date
- **November 14, 2018:** Public hearing was held in Denver
- Public comment period open until December 17, 2018
  - Docket ID: EPA-HQ-OAR-2017-0483

2016 New Source Performance Standards: Review

- Set emissions limits for methane and VOCs
  - Owners/operators meet limits using technologies that are cost-effective and readily available
  - Types of sources subject to the 2012 NSPS for VOCs did not have to install additional controls to reduce methane; the same controls reduce both pollutants
- Covered additional sources beyond the 2012 NSPS:
  - Hydraulically fractured oil wells
  - Pneumatic pumps at well sites and gas processing plants
  - Compressors and pneumatic controllers at transmission and storage facilities
  - Fugitive emissions monitoring and repair at well sites and compressor stations

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments

- On September 11, 2018, EPA announced a number of proposed amendments to the 2016 rule
  - Address a range of technical issues in response to administrative petitions
  - Clarify certain requirements in the rule
  - Address implementation issues that have been brought to the Administration's attention since the 2016 standards were issued
- EPA's regulatory impact analysis (RIA) estimates cost savings of up to $75 million per year, or a total of $484 million for the 2019-2025 period (3 percent discount rate)

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments

Fugitive Emissions: Monitoring

- 2016 Rule
  - Well sites: semiannual
  - Compressor stations: quarterly
- 2018 Proposed Amendments
  - Well sites:
    - Non-low production well sites: annual
    - Low production well sites: biennial (once every other year)
    - Monitoring can stop once all major production and processing equipment is removed from a well site, resulting in a wellhead-only well site
  - Compressor stations: semiannual and annual (co-proposal)

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Fugitive Emissions: Repair

- 2016 Rule
  - Repair all leaking components within 30 days of finding a leak
  - Resurvey to verify repair within 30 days of completing repair
- 2018 Proposed Amendments
  - Make first attempt at repair within 30 days of finding leak
  - Complete repairs within 60 days of finding leak

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Fugitive Emissions: Alaska

- 2016 Rule
  - *Well sites* on the Alaska North Slope
    - Initial monitoring:
      - Within 6 months of startup or by June 30, whichever is later (September – March startup)
      - Within 60 days of startup (April – August startup)
    - Annual monitoring thereafter
- 2018 Proposed Amendments
  - Expands well site requirements to *compressor stations* on Alaska North Slope

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Emerging Technologies

- 2016 Rule
  - Provided details for owners/operations to apply for an alternative means of emission limitation (AMEL)
  - Required 12 months of site-specific field data
- 2018 Proposed Amendments
  - Streamlined application requirements
  - Added allowance for modeling results to supplement field data
  - Allows owners/operators to apply with technology vendors or trade associations

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Equivalent State/Tribal Programs

- 2016 Rule
  - Same AMEL application process used for emerging technologies
- 2018 Proposed Amendments
  - Would provide a separate application process for states and tribes to apply for alternative fugitive emissions standards
  - Proposing alternative fugitive emissions standards for specific states, including Ohio and Pennsylvania, to streamline applications for existing state programs

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Pneumatic Pumps

- 2016 Rule
  - Required 95% control of emissions at well sites
  - Required a qualified PE to certify technical infeasibility of routing emissions to control at brownfield sites
- 2018 Proposed Amendments
  - Would provide technical infeasibility assessment at all well sites
  - Would provide option for in-house engineer to certify assessment

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Professional Engineer Certifications for Closed Vent Systems

- 2016 Rule
  - Required PE certification of closed vent systems
- 2018 Proposed Amendments
  - Would provide option for in-house engineers (appropriate expertise) to evaluate designs of closed vent systems and certify design/capacity sufficiency

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

2018 Proposed Amendments (cont.)

Other Proposed Amendments

- Would clarify requirements or improve implementation:
  - Definition of "capital expenditure" as it relates to equipment leaks at onshore natural gas processing plants
  - Definitions related to well completions
  - Calculation of "maximum average daily throughput" for storage vessels

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

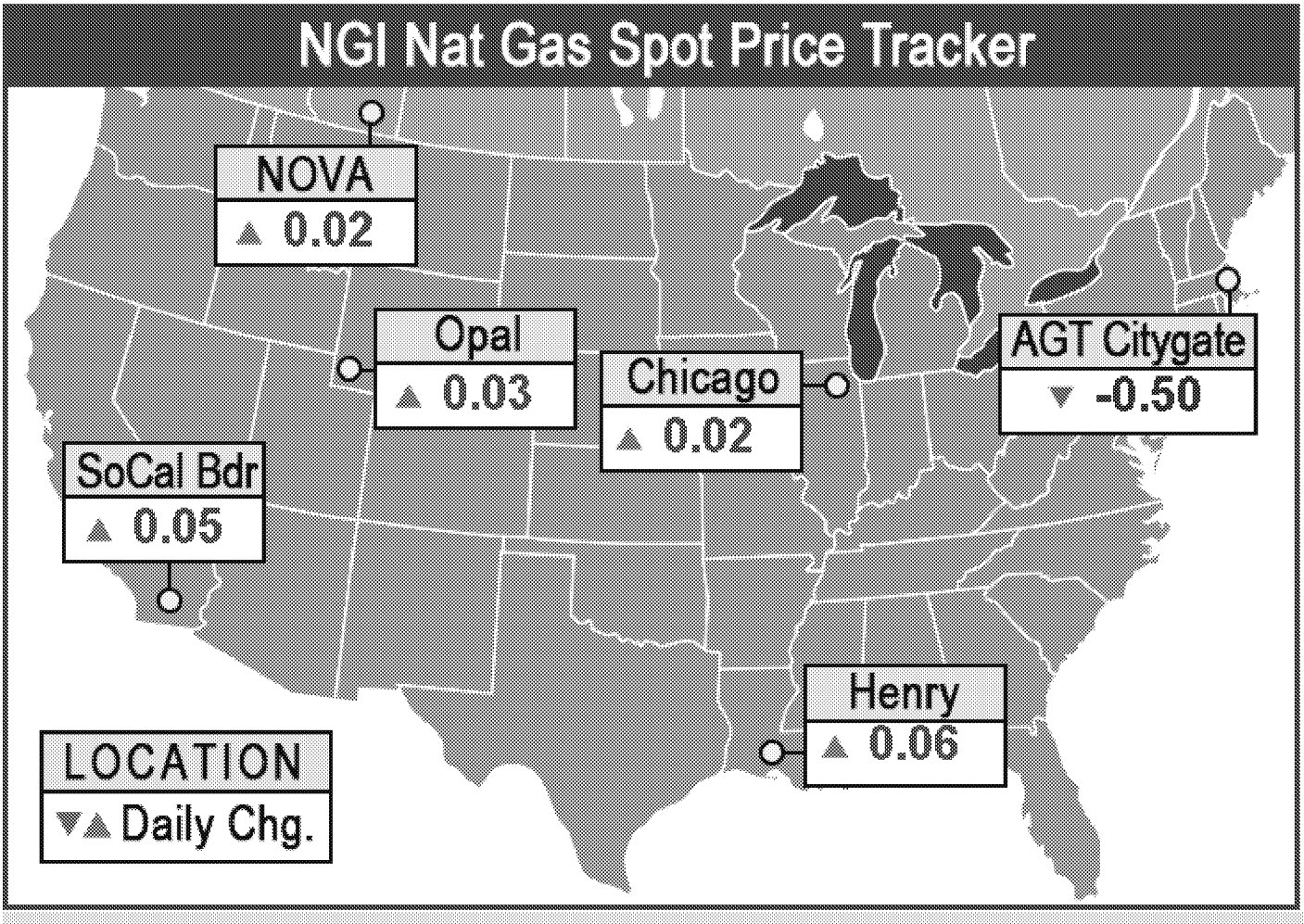
Oil & Gas Rule: Resources

- Contacts
  - NSPS:
    - Karen Marsh, marsh.karen@epa.gov
    - Amy Hambrick, hambrick.amy@epa.gov
- Resources
  - Small entity compliance guide for NSPS OOOOa (as of August 2016): https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

Message

From: Gilbreath, Jan [Gilbreath.Jan@epa.gov]
Sent: 4/20/2017 4:46:43 PM
To: Cozzie, David [Cozzie.David@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]
Subject: Methane rule



SoCal Bdr. | Opal | NOVA
Henry | Col. Gas | Chicago

Price Tables: *Daily* | *Weekly* | *Bidweek*

1Q2017 Earnings Calls List & Coverage

NGI's NatGas Prices - Biggest Movers			
Daily	Algonquin Citygate	▼	-0.50
Weekly	Tenn Zone 6 200L	▼	-0.94
Bidweek	Tennessee Zn 4 313 Pool	▲	+0.70
Shale	Haynesville - E. TX	▲	+0.08

- Cash Market Prices

EPA Reconsidering Methane Rules Covering Oil and Gas Industry

Charlie Passut

April 19, 2017

The U.S. Environmental Protection Agency (EPA) announced Wednesday that it will reconsider proposed rules governing new sources of methane emissions from the oil and natural gas industry, and it said it would delay by three months a compliance deadline for the rules.

The move comes less than two weeks after the Trump administration asked an appellate court to delay a series of lawsuits over three final rules -- collectively updates to the New Source Performance Standards (NSPS) that are designed to reduce methane, volatile organic compounds (VOC) and toxic air pollutants -- that EPA unveiled in May 2016, during the Obama administration.

An executive order (EO) issued by Trump on March 28 includes a directive for EPA to immediately review regulations on energy sources, and then to either suspend, revise or rescind them.

"EPA is continuing to follow through with President Trump's Energy Independence EO," said EPA Administrator Scott Pruitt. "American businesses should have the opportunity to review new requirements, assess economic impacts and report back, before those new requirements are finalized."

EPA said it will stay a June 3 compliance date for the rules for 90 days. In the interim, the agency will take public comments on the matter. EPA sent a two-page letter, which was signed by Pruitt, to petitioners that objected to the rules, including the American Petroleum Institute (API), the Texas Oil and Gas Association and the GPA Midstream Association.

According to Pruitt, the petitioners "raised at least one objection to the fugitive emissions monitoring requirements included in the final rule that arose after the comment period or was impracticable to raise during the comment period, and that is of central relevance" under rules governing the federal Clean Air Act.

"Among the issues raised...are objections regarding the provisions for requesting and receiving alternative means of emissions limitations and the inclusion of low-production wells," Pruitt wrote. "These provisions, or certain aspects of these provisions, were not included in the proposed rule so the public could not have raised objections to these provisions during the public comment period."

On April 7, Acting Assistant Attorney General Jeffrey Wood asked the U.S. District Court of Appeals for the District of Columbia Circuit to hold the lead case in the dispute, *API et al v. EPA et al*, No. 13-1108, in abeyance until 30 days after the EPA completed the review called for in the EO. Thirteen states, API and several other industry groups oppose the rules, while at least nine states and a coalition of environmental groups is in support.

Under the EO, Pruitt has 45 days to submit a review plan to the White House's Office of Management and Budget. A draft report on the EPA's actions is due within 120 days of the EO being enacted, and a final report is due within 180 days.

The rules were designed to help meet a goal by the Obama administration to slash by 2025 methane emissions from the oil and gas sector by 40-45% from 2012 levels.

EPA built NSPS upon VOC emission reduction requirements for new oil and gas wells that the agency first unveiledin April 2012. Those requirements called for a two-phase process to reduce VOCs: requiring flaring followed by "green completions," a term that means deploying equipment to capture and sell natural gas emissions that are otherwise lost.

EPA previously said it expected NSPS to reduce 510,000 short tons of methane in 2025, which is the equivalent of reducing 11 million metric tons of carbon dioxide. The rules were also expected to reduce other pollutants, including 210,000 tons of VOCs and 3,900 tons of air toxics, by 2025.

Jan Gilbreath, PhD
U.S. Environmental Protection Agency
Washington, D.C.
202-564-6279

Message

From: Srivastava, Ravi [Srivastava.Ravi@epa.gov]
Sent: 2/21/2017 9:36:05 PM
To: Carey, Angela [Carey.Angela@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]
CC: Srivastava, Ravi [Srivastava.Ravi@epa.gov]
Subject: Materials
Attachments: Oil & Gas_2-20-2017.pptx; Characterization_of_O&G_Operations_Sector_Emissions.doc; EmissionReduction-072011x.pdf; estimating-air-emissions-from-oil-and-g.pdf; methane_emission_reduction_opportunities.pdf; Methane_Emissions_from_Oil_Gas_Industry.pdf; reducing-methane-us-working-paper.pdf

Attached.

Thanks,
Ravi

Characterization of Greenhouse Gas Emissions Involved in Oil and Gas Exploration and Production Operations

Review for the California Air Resources Board by Angela Zahniser

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What greenhouse gas (GHG) emissions are associated with oil and gas extraction operations? The most significant sources in the oil and natural gas industries are carbon dioxide (CO_2) and methane (CH_4). However, nitrous oxide (N_2O) and Volatile Organic Compounds (VOCs) could be an important indirect air pollutant to account for, as hydrocarbon VOCs aid in the creation of ozone and in prolonging the life of methane in the atmosphere. However, effects can be variable and depend upon air quality conditions in the local area.

What are the different kinds of oil and gas extraction operations that produce emissions? GHGs are produced and emitted by various sources during the exploration, well development, production, and site abandonment phases. The American Petroleum Institute (API) categorizes the emissions sources of all oil and gas operations (including refineries) into five classifications:

a.) Combustion Devices—includes stationary (burners, flares) and mobile (trucks, ships) sources
b.) Point Sources—includes emissions from stacks, vents, ducts
c.) Non-point Sources—includes fugitive emissions of methane, wastewater treatment facilities, and other sources involved in waste handling
d.) Non-routine activities—activities associated with non-rscheduled maintenance or emergency operations
e.) Indirect emissions—emissions associated with company operations but physically occurring elsewhere, such as purchased electricity.[1]

During the exploration and well development phases, emissions occur from 1.) clearing the well pad and building roads; 2.) rigging up, drilling, and rigging down and 3.) well completion and testing. During the site production and abandonment phases, GHG emissions are produced by compressor engines, rigging pumps, and pipeline leaks, and will be affected by the number of well site visits and the well site facilities, which are composed of the type of disposal well, the plant and compressor station emissions, and other facilities. Emissions of CO_2 and CH_4 may also occur as a product of the biological oxygen demand (BOD) of wastewater, and as a result of abandonment procedures. The biological oxygen demand of the insects that are contained in the wastewater will determine if there are greenhouse gas emissions. Emissions will be CO2 if conditions are aerobic and CH4 if there are anaerobic conditions. GHG emissions will be highly dependent on the content of the wastewater, and the process through which it is handled.

Oil and Gas extraction processes and procedures are not uniform within the recovery industry and will vary according to well number and size, type of resource (oil, natural

---

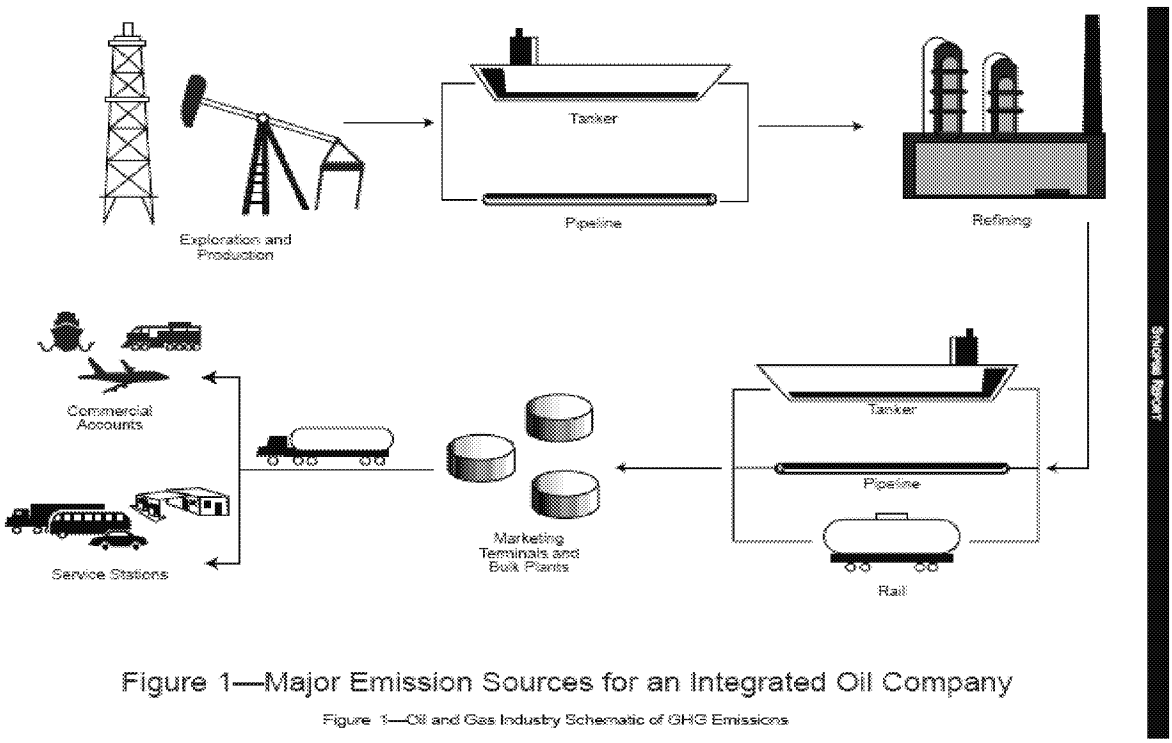
[1] American Petroleum Institute: Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations. Page 5.

gas, coalbed natural gas, or oil), amount of reserve, and geographical distribution (e.g. onshore or offshore) of the resource.

Carbon dioxide emissions are mostly the result of combustion emissions (vehicles, stationary engines, etc.), but could also be fugitive because CO_2 is also a component of natural gas. In estimating CO_2 emissions from combustion devices, it is important to determine the amount of fuel consumed, but categorizing it by the type of combustion device is unnecessary because the emission factors for CO_2 are relatively uniform across type of combustion devices.

The majority of CH_4 emissions are fugitive emissions from equipment such as separators, dehydrators, pipelines, wells, gas-powered devices, and miscellaneous other equipment. Methane is also emitted in the exhaust of natural gas combustion engines and turbines, and from operator and control devices. Accidental release can also be a source of methane emissions. Emission factors for methane do vary according to the type of combustion device, and could contribute as much as 17% of greenhouse gas fuel-use emissions.[2] N_2O emissions from fuel combustion are a much less important contributor to overall fuel-use GHGs.

While this report focuses on emissions in the oil and gas exploration and production side, the diagram below depicts the operations and emissions sources for the lifecycle of oil and gas industry operations:



Source: American Petroleum Institute: Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations. Page 4.

[2] Canadian Association of Petroleum Producer, Technical Report on A National Inventory of Greenhouse Gas, Criteria Air Contaminant, and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry, Volume 4. Page 16. [HYPERLINK "http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=86224"]

The following is a more detailed outline of the process of oil and gas exploration and production, and the possible sources of greenhouse gas emissions associated with them:

1. Exploration Phase:

A. Seismic waves are generated in an area to determine if there is a reasonable chance that a sufficient amount of hydrocarbons (oil and/or gas) is present and will be discovered if an exploratory well is drilled. These waves can be generated by a variety of sources including the detonation of explosives in holes below the earth's surface; marine airguns (commonly used in offshore exploration); and vibroseis, (specialized trucks that place vibrating pads on hard surfaces such as paved roads in order to create seismic waves). In California, vibroseis is the most common exploration method, and explosive devices are rarely used.

GHG Emissions: Depending on method used, CO_2 emissions from truck motors used in vibroseis or th sue of explosive devices.

2. Well Development Phase:

Natural gas taken from the process is usually the principal type of fuel used for stationary combustion devices. Liquid fuels such as diesel or gasoline are generally used for mobile sources such as trucks and construction equipment. Compressors, pumpjack engines, and portable heaters and torches also sometimes use propane.

A. *Clearing Area for the Well Pad:* Large diesel powered trucks are often used to clear an area where the well pad is located. In more recent years, smaller amounts of acreage have been disturbed for the actual well pad. Increased use multi-rig pads can also reduce amount of surface acre disturbance, therefore decreasing number of trucks and truck trips needed for well pad clearance. Additionally, depending on the size of the well, the location, and the number of well pads being cleared, disturbing vegetation could have the effect of eliminating an already established carbon sink through destruction of vegetation and through disturbing organic carbon stored in soil.

GHG Emissions: CO_2 combustion emissions from fuel used in trucks. Additionally, one-time and potentially long-term effects could include lost carbon sinks due to surface and vegetation disturbance.

B. *Constructing Roads:* Constructing Roads for oil and gas extraction is also a source of GHG emissions, mainly due to fossil fuel combustion emissions from vehicles used to build roads to the wells and rigs. In addition, surfactants are often used on roads for dust prevention. Depending on the type of surfactant used, there could be greenhouse gas emissions associated with the manufacture and application of these surfactants. Generally, there are two types of roads:

1. Access Roads –shorter roads that lead the resource road to the individual well pad

2. Resource Roads--longer, wider, more arterial roads that feed into the access roads

GHG Emissions: Combustion emissions, CO_2, from fuel used in trucks. Additionally, one-time effects could include lost carbon sinks due to surface and vegetation disturbance (see Section 2A).

C. *Rigging Up and Drilling*: The process of setting up a drill rig and performing the actual drilling is a source of GHG emissions from fossil fuel combustion. "Rig" is a general term that refers to the complex set of equipment that is used to drill through the surface of the earth to sample and extract resources. In addition to the actual drill, equipment could include de-sanders, de-silters, vacuum de-gassers, diesel engines, the derrick, etc. Several factors may influence the type and amount of GHG emissions. First, drill rigs are used for both exploration and production, i.e. they are used to identify reservoirs as well as extract resources from those reservoirs over the longer term. A pumping rig is sometimes called a derrick—it is generally the centerpiece of the rig. Rigs and derricks can either be mobile or stationary, small and portable (e.g. rigs used in exploration drilling), or very large and capable of drilling through thousands of feet. Factors influencing the size and type of rig are: whether or not directional drilling is being performed, the size of the operation, anticipated length and intensity of the operation, and the depth and range of the well. Rigs often have a lot of equipment, such as de-sanders and de-silters, and vacuum degassers, which remove gases. Drilling rigs could have fugitive emissions from leaks in equipment (i.e. pipe fittings), and combustion emissions from operation of the engines and heaters used by the rigs. Combustion emissions should be assessed based on fuel consumption, including the type of fuel consumed by engines and boilers.

GHG Emissions: CO_2 combustion emissions from fuel used by rigs. Many rigs are powered with electricity. Therefore, indirect CO_2 emissions could occur from the fuel input used in the electrical generating unit.

D. Drilling Fluids: Drilling fluids are used to cool and lubricate the drill bit and to remove rock fragments, and to balance formation pressures. Drilling fluids may be gas, foam, or liquid-based fluids (such as water-based muds). Water-based muds are the most common. There are two potential causes for GHG emissions from drilling fluids: entrainment of solution natural gas and volatilization of drilling fluids. Generally, the net emissions from entrainment are considered to be insignificant when compared to GHG emissions from other sources at the drill site. Usually, invert fluids are composed of about 80% diesel 20% water vapor. The Canadian Association of Petroleum Producers estimate emissions from use of invert fluids by calculating the evaporation rate in the mud

tanks, and applying the result to the total number of operating hours accumulated in the reference year.[3]

GHG Emissions: Possible CO_2 and CH_4 from flaring or venting of the vapors associated with the drilling fluids

E. Casing: To stabilize the well hole and prevent caving, well casing is placed in the well. The casing is important because it prevents natural gas, oil, and brine from leaking into nearby aquifers.

GHG Emissions: Although likely to be insignificant, possible CH_4 fugitive emissions leaks.

F. *Well Completion and Testing (drilling is complete):* When drilling to the reservoir is complete, the well is tested to ensure whether there are enough hydrocarbons to justify well completion and production. Possible tests that may be performed are coring, wireline logging, and drill stem testing. CO_2 and CH_4 may be emitted during the process, depending on which method is used. Fugitive emissions of methane from initial rock fracturing, from flaring, and from compressor stations may occur during this stage.

1. **Fracturing:** Fracturing may also occur during well completion and is a process that involves injecting a substance (usually water) under high pressure down into the rock to blow it open and open up pore space in the rocks, which releases the oil or gas. It occurs after the well is drilled and when it has been determined that the oil or gas doesn't easily come to the surface. Some operations will use produced water from other wells.

   GHG Emissions: Fugitive CH_4 emissions, CO_2 from fuel used in injection machinery. Diesel trucks are often used.

2. **Flaring:** Flaring, or burning off of excess or waste gas or flammable gas, is sometimes performed when the gas has become over-pressurized. It is also sometimes done prior to initial resource extraction to burn off initial waste gas for one or two days, and then intermittently as needed throughout the extraction process.

   GHG Emissions: CO_2 and CH_4 However, in California, flaring is allowed only in specific circumstances and it is on a case by case basis. The company must apply for a permit to flare, which is issued by the county or local air board.

3. **Venting:** Venting is the direct release of gas into the atmosphere. It occurs at a number of points in both the oil and gas development process, including well completion, well maintenance, pipeline maintenance, and tank maintenance. Large quantities may be vented to the atmosphere.

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[3] Canadian Association of Petroleum Producer, Technical Report on A National Inventory of Greenhouse Gas, Criteria Air Contaminant, and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry, Volume 4. Page 66. [HYPERLINK "http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=86224"]

The alternative to venting is flaring (see F.2.). This raw natural gas may also contain carbon dioxide.

GHG Emissions: Because venting in California is not allowed, CO_2 or CH_4 from fugitive emissions could occur. All tanks are covered tanks, and often, a unit will have a vapor recovery system attached. Also important to note is that compliance with venting procedures could be a critical factor in the estimation of GHG emissions.

4. **Compressor Engines:** Compressor engines pressurize the gas in the pipe so that it can more easily move throughout the reservoir. They may be located on the ground next to the well head; however, if the gas is under high natural pressure, compressor engines are unnecessary. Smaller compressor engines have less overall emissions, though they have higher emission rates. Compressor units generally operate with either a reciprocating engine or a turbine engine. Reciprocating engines that operate on natural gas range in size from about 30 to 3500 kW, and operate at speeds of 800 to 1800 rpm. Gas turbine engines generally range from 1 to 25 megawatts. Gas turbines generally emit less exhaust than reciprocating engines, where methane emissions are an order of a magnitude lower than in reciprocator engines.[4]

GHG Emissions: CO_2 associated with combustion of fuel input (diesel or natural gas) into the compressor engine.

5. **Tubing Installation:** Tubing to carry liquids and gas to the surface is usually installed after testing has warranted well production capability. Equipment and installation could include pump separation equipment, and a pipeline connector or storage tank.

GHG Emissions: Fugitive CH_4 emissions and CO_2 emissions from fuel combustion associated with installation of equipment.

3. Primary and Secondary Production Phases:

A. Compressor Equipment: As in the well completion and testing phase, equipment used to increase the reservoir pressure is often used. Equipment may include compressor engines, stations, pumps, or gas lift valves. They are used throughout the production phase in order to continue to pressurize the gas in the pipeline(s) so that it can more easily move throughout the reservoir. They may be located on the ground next to the well head; however, if the gas is under high natural pressure, compressor equipment may be unnecessary. Smaller compressor engines have less overall emissions, though they have higher emission rates. In multi-pad operations, there may also be centrally located compressor stations, which provide energy to the smaller wellside stations in the

[4] Canadian Association of Petroleum Producer, Technical Report on A National Inventory of Greenhouse Gas, Criteria Air Contaminant, and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry, Volume 4. Page 21. [HYPERLINK "http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=86224"]

area. They are usually large buildings and can be fueled by diesel or natural gas. Compressor units generally operate with either a reciprocating engine or a turbine engine. Reciprocating engines that operate on natural gas range in size from about 30 to 3500 kW, and operate at speeds of 800 to 1800 rpm. Gas turbine engines generally range from 1 to 25 megawatts. Gas turbines generally emit less exhaust than reciprocating engines, where methane emissions are an order of a magnitude lower than in reciprocator engines.

GHG Emissions: CO_2 and CH_4 associated with combustion of fuel input (diesel, natural gas) by the compressor equipment.

B. Secondary and Tertiary Recovery: Because primary recovery of oil and gas only extracts a fraction (about 25%) of the available resource, secondary and tertiary recovery methods are often employed. Water is often re-injected. Gas could also be injected to enhance gas cap drive. Substances, such as steam, carbon dioxide, surfactants, and microbes, can also often be injected to help mobilize the resource. This process is often energy intensive.

GHG Emissions: Fugitive CH_4 if gas is reinjected; CO_2 from combustion emissions of injection equipment. Fugitive emissions of CO_2 if used as an injectable fluid.

E. Wellsite Visits: During production, there will generally be routine wellsite visit schedule. Frequency of visits will vary among operations, but fossil fuel emissions associated with truck trips can be significant. Documentation of frequency and distance traveled is important.

GHG Emissions: CO_2 from fuel combustion during truck visits

F. Wellsite facilities: Two pieces of important equipment at the well site are the separator and the dehydrator. With these two pieces of equipment, there are sometimes smaller flares to prevent pressure buildup. There are also sometimes disposal wells or evaporation ponds installed next to the well pad.

1. **Separator**–the piece of equipment separates the resource from any other organic liquids. The liquid that is taken off (separated) is called condensate. The gas is fed into the pipeline, and the condensate remains.

   Crude Oil Separation (oil recovery only): After the oil is extracted, gaseous components and other solids must be separated and removed before it is transported to a refinery.

   GHG Emissions: Fugitive CH_4 emissions and CO_2 emissions associated with separation equipment.

   Natural Gas Conditioning (natural gas recovery only): After extraction, natural gas is conditioned to remove impurities from the stream so that it can be transported through pipelines. However, it is not always required if the natural gas is pure enough. Impurities may

include hydrogen sulfide and nitrogen. Conditioning is performed either through dehydration or sweetening. Sweetening removes H_2S and CO_2 from the gas stream, usually by amine treatment. The sulfur may be disposed of by flaring or sending it to a sulfur-recovery unit for sale.

GHG Emissions: CO2 emissions that may be vented after separated from the gas stream

2. **Dehydrator**—the dehydrator removes the water from the resource. The most common type is called a glycol dehydrator. The emissions associated with these are volatile organic compounds (which indirectly adds to the lower atmosphere ozone load), and methane leaks associated with the hooking up of pipes.

   GHG Emissions: CO_2 or CH_4

3. **Wastewater Disposal:** After the condensate is separated from the resource, the disposal method by which the condensate is dealt with varies among operations. Sometimes, trucks will transport it away. Other times, a pipe system is constructed and the condensate is piped out to a central facility for treatment or disposal. Generally, condensate is only piped out when a large operation is ongoing. Still other times, this water is used for fracturing or is reinjected into a well for disposal. Other times, evaporation ponds are created to dispose of the contaminated wastewater. Contaminants in the wastewater are highly variable depending on the geology of the area. Most of it is inorganic, and includes salts, sodium chloride, sulfates, bicarbonates and other salts and minerals. There may also be some VOC's mixed in with the resource, including benzene. The concentrations of these contaminants varies widely. Areas on the western side of California generally contain a higher salt content than those on the east side of the valley.

   California water quality regulations require that, prior to wastewater discharge to evaporation ponds, the operator must inform the Water Quality Board. The Water Quality board will then determine if a permit is required. If the wastewater is being re-inject or otherwise recycled back into the earth, the operator must go through the California Division of Oil, Gas, and Geothermal Resources to determine proper procedures.

   Because of the contaminants in the wastewater, the biological oxygen demand (BOD or Chemical Oxygen demand, COD) may result in CO_2, CH_4, or N_2O emissions, especially if the disposal unit is an evaporation pond. These emissions are the result of aerobic respiration and anaerobic fermentation. Earthen pits that are exposed to the air are often used to store or evaporate the wastewater from the dehydration and/or separation equipment, and also to store the wastes from the drilling fluids and fracturing fluids. Natural gas, VOCs, and chemical

emissions from surfactants, solvents, and lubricants may be emitted. Some of the lighter or more volatile chemicals and compounds will evaporate from the ponds into the atmosphere. To determine emissions from the wastewater in terms of methane per BOD, one should look at the type of treatment system that is used to manage the waste. Larger, centralized treatment facilities can control anaerobic environments, and are more likely to capture and re-use methane while smaller decentralized methods have less control over the anaerobic environment and are unlikely to capture methane emissions for re-use.

GHG Emissions: CO_2 , CH_4, and VOCs

4. **Other Facilities:** There may be other plants or facilities used to meet industry needs, which may result in other types of emissions sources (e.g. amine plants, evaporation ponds, land farming operations).

   GHG Emissions: CO_2, CH_4, others.

G. Leaks: Throughout the lifetime of the well (exploration, development, and production), fugitive emissions from leaks will occur. This could include leaks in the casing and tubing, valves, tanks, open pits, or leaks that occur from routine maintenance and replacing of motors and other equipment. The primary types of equipment that leak are: reciprocating compressor packing systems, centrifugal compressor seals, valves, pump seals, connectors, pressure regulator diaphragms, pressure-relief devices, and open-ended valves and lines. Almost all equipment is expected to leak some amount, yet most of it doesn't leak sufficiently from one particular source to warrant a repair. Generally, if excessive leaks are under 2% of the potential leak sources, the operations are considered normal.[5]

GHG Emissions: CH_4, CO_2, and other VOCs

H. Accidental Acute Release: Though rare due to installed control measures, an oil or gas well will occasionally have a blowout. They can occur at any phase of the operational process, and happens when a drill encounters a zone of unexpected or non-uniform pressure. Formation fluid and drilling fluid can rise to the surface, and can ignite an engine spark. Blowouts can take from several days to several months to control.

GHG Emissions: CH_4, CO_2 that is a natural part of the gas

[5] Canadian Association of Petroleum Producer, Technical Report on A National Inventory of Greenhouse Gas, Criteria Air Contaminant, and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry, Volume 4. Page 51. [HYPERLINK "http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=86224"]

4. Site Abandonment:

A. When the well is finished producing, plugging and abandoning the well can take various forms. Each state has specific requirements that govern well abandonment. In California, regulations require that heavy drilling mud and several cement plugs be placed at specific intervals.[6] These plugs are strategically placed to prevent migration of residual oil and gas to other zones, aquifers, or to the surface. Sometimes, when CO_2 has been used for enhanced secondary or tertiary recovery, part of the abandonment procedure involves blowing down the well to release any existing pressure. If this is done, large amounts of CO_2 could be released into the atmosphere.

GHG Emissions: CO_2 and CH_4 from venting

Information Sources:

American Petroleum Institute: Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations
[HYPERLINK "http://www.climatevision.gov/sectors/oil_gas/pdfs/ghg_synopsis.pdf"]

U.S. Environmental Protection Agency, Office of Compliance Sector Notebook: Project Profile of the Oil and Gas Extraction Industry, October 2000.
[HYPERLINK "http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oilgaspt1.pdf"]

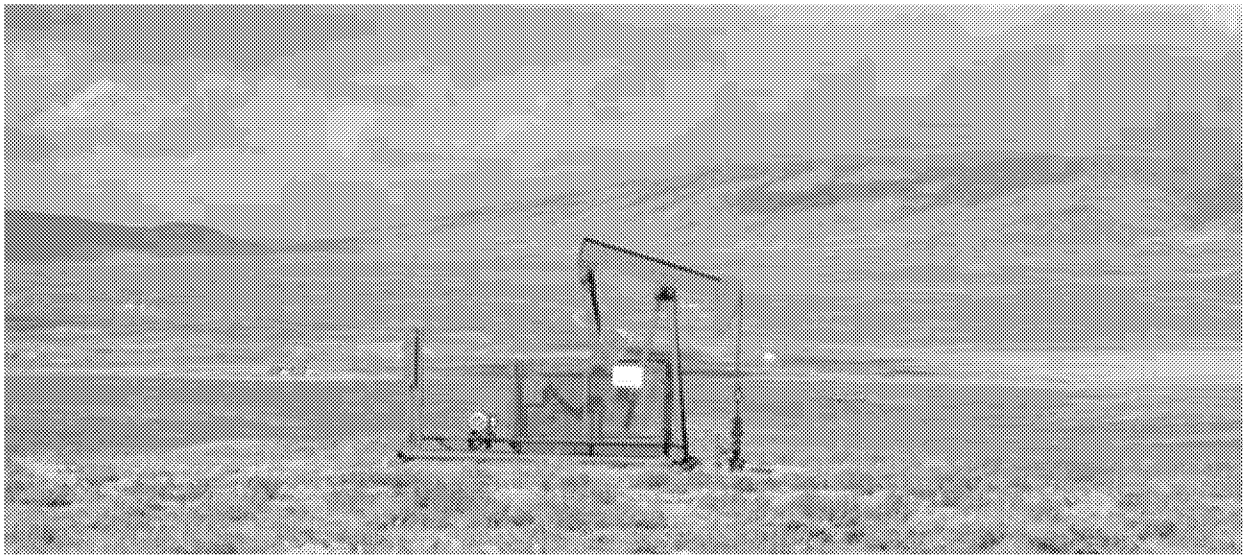
2007 Draft U.S. Greenhouse Gas Inventory Report Draft Inventory Of U.S. Greenhouse Gas Emissions And Sinks: 1990-2005, February 2007. **[HYPERLINK "http://epa.gov/climatechange/emissions/usinventoryreport07.html"]**

Canadian Association of Petroleum Producer, Technical Report on A National Inventory of Greenhouse Gas, Criteria Air Contaminant, and Hydrogen Sulphide Emissions by the Upstream Oil and Gas Industry, Volume 4. [HYPERLINK "http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=86224"]

[6] [HYPERLINK "http://web.ead.anl.gov/dwm/regs/state/california/index.cfm"]

Emission Reduction Techniques for Oil and Gas Activities

U.S. Forest Service
2011



FOREWORD

This document is intended to provide techniques which may be applied to oil and gas operations to reduce or mitigate emissions from development and production operations. Emission reduction techniques described herein can be applied to existing operations or considered as mitigation measures to be applied in planning and analysis of potential future development. Depending upon their intended applications, users of this document may consider directly using or recommending an emission reduction technique described here, modify one of the described emission reduction techniques for use in a unique situation, combine two or more techniques, or use this information as a basis to research other unforeseen technology.

How to Use This Document

The table of contents is designed to provide information on the specific emission reduction technique (such as the emission type it will correct), the actual pollutants that will be reduced, and the pollutant effects. Each technique is color-coded to easily display the types of emissions that will be addressed by that specific technique. After each technique in the table of contents is an abbreviated listing of the pollutant(s) that will be reduced by that specific technique and a symbol that represents the pollutant effects this technique will reduce. The key for color coding reduction techniques, pollutant reduced, and pollutant effects is located on the following page.

This document is based on a powerpoint presentation created by the BLM in 2009 and technical material from the EPA Gas Star program. (References)

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Foreword

Key to abbreviations & symbols:

POLLUTANT REDUCED

PM	coarse particulate matter
NOx	oxides of nitrogen
CO	carbon monoxide
VOC	volatile organic compounds
HC	hydrocarbons
CH4	methane

POLLUTANT EFFECTS

◆	near-field visibility
✤	far-field visibility
✪	deposition
✳	ozone

REDUCTION TECHNIQUE

Color coding:

- dust treatment
- reducing roadway emissions
- controlling or reducing combustion emissions
- controlling or reducing hydrocarbon emissions

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Introduction

Oil and gas development that occurs on or near public lands, including lands managed by the USDA Forest Service, brings potential impacts to air quality and an accompanying focus on means to reduce emissions. Reducing emissions to the air may occur in any phase of oil and gas development; this document is organized by emission reduction techniques that apply to transportation, construction and drilling, production, and monitoring and maintenance. Use of these techniques may reduce project emissions and thus prevent significant impacts to Ambient Air Quality Standards or Air Quality Related Values.

As explained further below, this document is intended to serve as a reference and guide. It may apply to oil and gas projects that federal decision makers determine to be actions under the National Environmental Policy Act (NEPA). However, the document is neither intended to be used solely for NEPA purposes nor will it be binding when it informs the NEPA process. End users of this document must be conscious of their authority (see section 0.5) and will have the responsibility to interpret the use of this information in the appropriate context.

0.1 Users of This Document

The primary intended audience of this document will be front-line NEPA practitioners in Forest Offices, District Offices, and Regional Offices of the USDA Forest Service. Nevertheless, it is hoped that the document will prove useful to a wide array of users including other Federal Land Managers, oil and gas operators, state and federal regulators, and tribal governments. This document provides information that will be valuable when proposing and conducting an analysis of proposed projects (such as in NEPA and other air quality analyses outside the NEPA setting), and mitigating impacts from proposed emissions. The information presented here can also be used to retrofit existing operations if or when Ambient Air Quality Standards or Air Quality Related Values are exceeded or impacted. Examples of suggested wording for use in planning documents such as NEPA documents are included as tables 1 through 4, which can be found at the ends of their respective sections.

0.2 Intended Use

By using the color-coding and quick reference symbols for pollutant effects shown in the key on page iv, casual users should be able to readily use the document as a general source book for emission reduction techniques. In such use, the reader can use the mitigation tables simply as additional reference material. The document can also serve as a reference for staff in an advisory capacity in a non-NEPA setting (such as for oil and gas development near a National Forest but where no federal action is involved). Oil and gas operators may refer to the document as an aid in planning development and may find wording that will be the basis of operator-committed practices. Operators may be aware of effective emission reduction techniques not included in this document; they are encouraged to use these techniques and bring them to the attention of the USDA Forest Service.

In a NEPA setting involving formal discussions among the USDA Forest Service and other stakeholders, wording in this document may be adapted into mitigation language. If such language is ultimately written into a Record of Decision, it will be revised to be mandatory. The U.S. Environmental Protection Agency (EPA) recommends that mitigation measures, whether discretionary or required, that affect emissions from NEPA projects always be disclosed in NEPA documents including the Records of Decision.

The sections below describing emission reduction techniques or technologies and their characteristics

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include general information on emissions reduced and other benefits, authority and applicability, and limitations. Benefits and limitations do not all carry equivalent weights; some benefits may outweigh some limitations and vice versa. Applicability may depend upon the setting, and some emission reduction techniques may be required or restricted depending upon the jurisdiction and the airshed.

Cost is often a factor and is mentioned in connection with several of the techniques discussed below. In order to limit the length of this document and extend its useful lifetime, it does not attempt to analyze the costs and benefits of specific techniques. Thorough cost-benefit analyses can be complex and are subject to change with the economy and advances in technology. Nevertheless, cost-benefit analysis is a useful tool and should be considered in decision making. Resources such as EPA's Gas STAR Web site (see section 5.0) give information on cost-benefit for emission reduction techniques. This document will be updated annually to incorporate new techniques.

0.3 Protection of Air Resources

This paper identifies a range of typical emission reduction techniques for protecting air resources during oil and gas development and production operations. This is a partial list. For additional air resource emission reduction techniques and more detailed technical and investment-payback information, please visit the websites listed in section 5.0. Nothing in this presentation is an endorsement of a particular company, product, or service.

Please consult with the appropriate Forest Service Air Quality Resource Manager and the appropriate Air Quality Regulatory Agencies to discuss the use or implementation of these techniques to reduce emissions.

Using emission reduction techniques can reduce the following emissions:

- Hazardous Air Pollutants – can cause serious health problems
  - Benzene, toluene, xylene, formaldehyde
  - Ethyl-benzene, n-hexane
- Criteria Pollutants – national standards to protect health and welfare
  - PM_{10} (dust), $PM_{2.5}$, carbon monoxide, sulfur dioxide, ozone, nitrogen oxides
- Volatile Organic Compounds – contribute to ozone formation
  - hydrocarbon compounds excluding methane and ethane
- Greenhouse Gases – contribute to climate change
  - Carbon dioxide, methane, nitrous oxide (N2O).

0.4 Where Do Emissions Come From?

This document presents emission reduction techniques that may apply to the transport, drilling, and production phases of oil and gas development. Various categories of sources can emit pollutants during each phase.

- Combustion Emissions: include criteria pollutants, volatile organic compounds, greenhouse gases, hazardous air pollutants.
  - Come from: vehicle tailpipe exhaust emissions, dehydrators, mobile and stationary engines, flaring

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- Fugitive Emissions: include criteria pollutants, volatile organic compounds, hazardous air pollutants, greenhouse gases
  - Equipment leaks, evaporation ponds and pits, windblown dust (from truck and construction activity)
- Vented Emissions: include greenhouse gases, volatile organic compounds, hazardous air pollutants
  - Dehydrator vents
  - Condensate tanks, storage tanks
  - Venting during completion events

0.5 Who Has the Authority to Authorize or Require Emission Reductions?

The authority to select or require an emission reduction technique will vary depending upon the laws and regulations that apply to a given situation. Emission reduction techniques may be selected or committed to by the applicant or operator. Such a commitment may not require regulatory authority; however, it may still be necessary to disclose the commitment as mentioned in section 0.2. In some cases, emission reduction technologies or goals for emission reductions will be required as a lease notice or stipulation by the Federal Land Manager. Air quality regulators and Federal Land Managers may require emission reduction techniques with the operator as a form of mitigation under NEPA. Many categories of sources and processes are regulated under federal or state law. Coordination with the appropriate state air quality control agency is essential.

The following sections of the document discuss selection of emission reduction techniques in more detail. There is also a discussion of air quality monitoring and the maintenance aspect of oil and gas development. Each section contains a part on air resource planning that suggests concepts to use when writing planning documents. Most of the examples of wording come from documents that were written pursuant to the National Environmental Policy Act; as explained in section 0.2, some of the wording may need to be revised if it is to be adapted to a Record of Decision, for example.

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1.0 Air Resource Emission Reduction Techniques Transport

Transportation of workers, materials, and equipment begins with initial surveys and continues for the life of the project. Vehicles can emit pollutants directly and by disturbing dust on paved or unpaved roadways. Some of the techniques described in this part involve various forms of centralization, which can reduce emissions by reducing the distance traveled on roads or the number of trips. However, centralized development can present its own set of problems. As discussed further in subsequent sections, centralization can increase some emissions such as by increasing the time and power required to drill wells. Similarly, electrification can reduce emissions in the immediate project area but, by increased use of electricity, lead to greater emissions from distant electric generating stations. A planning process that involves the proponents or operators, the state air quality control agency, and other stakeholders should evaluate the relative emissions of the techniques described below and their alternatives. In addition, check with local authorities regarding allowable use of any of these emission reduction techniques.

Representative Emission Reduction Techniques – Transport

Emission reduction techniques that may apply to transportation include directional drilling; centralized water and condensate storage, water delivery, fracturing, and liquids storage; use of liquids gathering systems; telemetry; automation of wells; control of fugitive dust control; and vanpooling. These topics are discussed in this section.

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1.1 Traffic Reduction

Much oil and gas development occurs in rural, and sometimes remote, areas with sparse access to infrastructure such as rail lines and mass transit. Most transportation around rural oil and gas fields is by truck or car, with their accompanying emissions. In remote areas, the ability to combine trips or carpool is limited or nonexistent, particularly in early stages of development. Nevertheless, reducing trucking and service traffic can reduce associated dust and tailpipe emissions.

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust and construction activities.

Benefits:

- Reduces on-road emissions from exhaust.
- Reduces entrained particulate matter as road dust.
- Reduced road wear.
- Improved safety.

Where this can be applied:

- At least to some extent, to most projects.
- During development when coordinated crews are working rotating shifts.
- May more readily apply as development of a field progresses by gradually decreasing the ratio of miles traveled to sites visited and increasing opportunities for multi-passenger trips.

Limitations:

- Requires administrative authority (such as by company policy), otherwise will be limited as a voluntary program.
- Limits to the minimum number of trips required for tasks including safety-related activities and essential maintenance.

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1.2 Directional Drilling of Multiple Wells Per Pad

This section discusses the use of directional drilling to drill multiple wells from a well pad, although directional drilling can also occur on a single-well pad. The environmental benefits to be gained from directional drilling will vary depending upon the location, geology, and other factors. In spite of other environmental benefits, air quality benefits relative to vertical drilling may not be realized in all cases. Accordingly, we treat this technique as one in which the potential to reduce air emissions is not pre-ordained but still should be considered.

Where directional drilling reduces emissions, reductions come from decreasing the number of pads and thus not constructing an equal number of separate roads. Accordingly, one obvious and immediate environmental benefit is to limit fragmentation of the landscape. Construction of a single pad normally can substantially reduce surface disturbance thereby reducing dust emissions relative to building multiple drill sites.

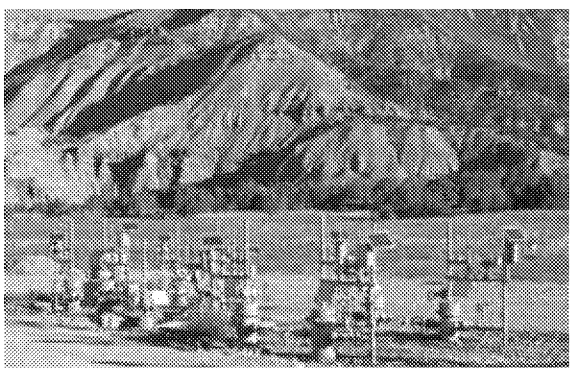
Directional drilling may require more power and thus have a greater potential for emissions than vertically drilling to the same point of contact with the producing horizon. However, drilling from a single pad can also reduce future travel on the network of roads in the oil and gas field. Recent advances in technology have also reduced drilling time on directional wells. Other experience with emission reduction for large drilling engines, such as with tier 2 and tier 4 diesel engines, has successfully shown reductions in air emissions from directional drilling. Large (over 750 horsepower) tier 2 diesel engines have been available from manufacturers since the early 2000s, and the manufacture of large tier 4 diesel engines is to be phased in by 2015.

Given the above issues, a careful analysis will be required to weigh the advantages and limitations of directional drilling. The topic is discussed further below.

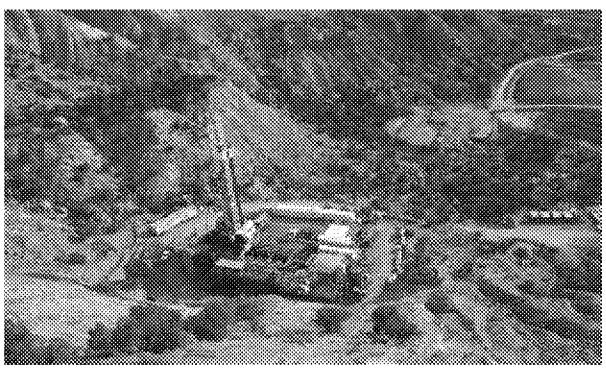
Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust and construction activities.
- Future reduction of volatile organic compounds due to consolidated production facilities by making the capture of volatile organic compounds and methane more economically viable.

Benefits:



There are sixteen wells on this well pad.



View of an efficiency drilling rig.

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- May decrease vehicle traffic; i.e., reduce road and pad construction related dust and emissions, in the construction and rig move phases.
- Reduces road network.
- May reduce truck traffic dust and emissions during production.
- Facilitates the use of consolidated production facilities, making controls more efficient and cost-effective on volatile organic compound and oxides of nitrogen emissions.

Where this can be applied:

- This may be applied in most development scenarios, though it is sometimes used in exploratory developments where access is limited due to terrain or minimal ground disturbance is desired.

Limitations:

- Oxides of nitrogen, carbon monoxide, and carbon dioxide and other engine emissions from drill rigs are much larger per engine than those associated with vehicle traffic. Therefore, the increase in drill time from directional drilling may result in a short-term emissions increase, even if emissions from vehicle traffic decrease in the long term.
- This may not work in exploration phase of development, because the field has not yet been delineated.
- In some areas, the geologic structures are not suited to directional drilling.
- Total air emissions might actually increase as a result of directional drilling due to the increase in true depth, i.e., greater distances drilled, greater drill times, and increased overall energy use.
- Technical, down-hole limits on directional drilling remain in spite of tremendous advances.

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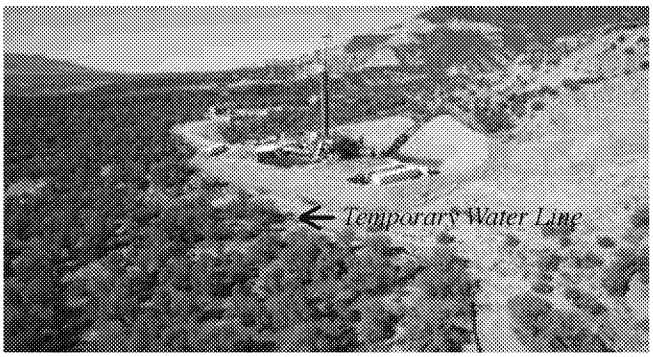

1.3 Centralized Water Storage and Delivery

Using centrally stored water that is piped to the well pads and fracturing facilities through a temporary, plastic, surface line.

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Reduces the number of truck trips for hauling water.
- Decreases dust from road traffic.
- Reduced tailpipe emissions.
- Less disturbance of wildlife.

Where this can be applied:

- Can be used for developed and producing wells.
- Can be applied to individual or consolidated facilities.

Limitations:

- May not be feasible in some terrain.
- May not be feasible if wells are too far apart.
- Emissions occur during construction of centralized facility.
- May not be feasible if the collection point is too far away. However, water could be piped to a consolidated collection point thereby still reducing some of the road traffic.

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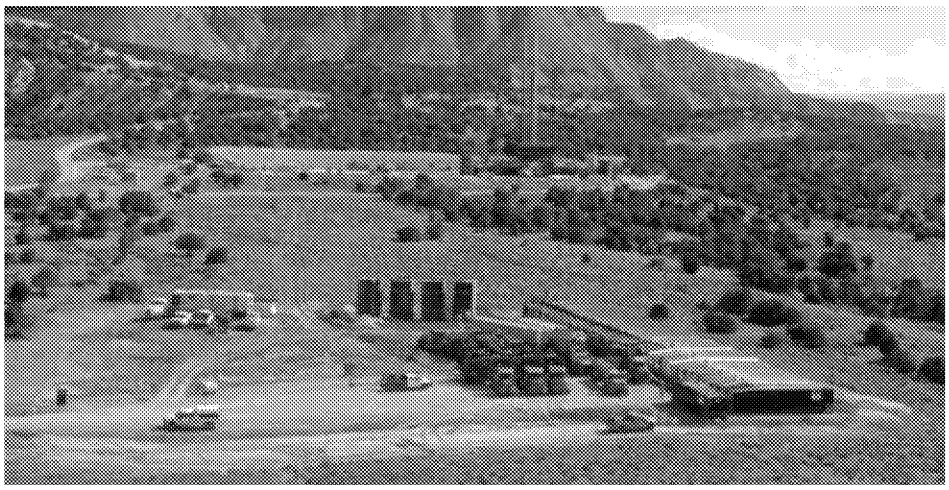

View of Fracking Site

1.4 Centralized Fracturing

Using centralized fracturing pads with hard-line fracturing pipes, some running over one mile, that can serve many well pads - representing hundreds of wells in all.

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Reduces movement of fracturing trucks and personnel.
- Decreases dust from road traffic.
- Reduced tailpipe emissions.
- Less disturbance of wildlife.

Where this can be applied:

- Where geological conditions are conducive.
- Where emissions from constructing fracturing pipes and other costs do not outweigh emission reductions.

Limitations:

- In some areas, the geologic structures are not suited to centralized fracturing.
- Emissions occur during construction of centralized facility.

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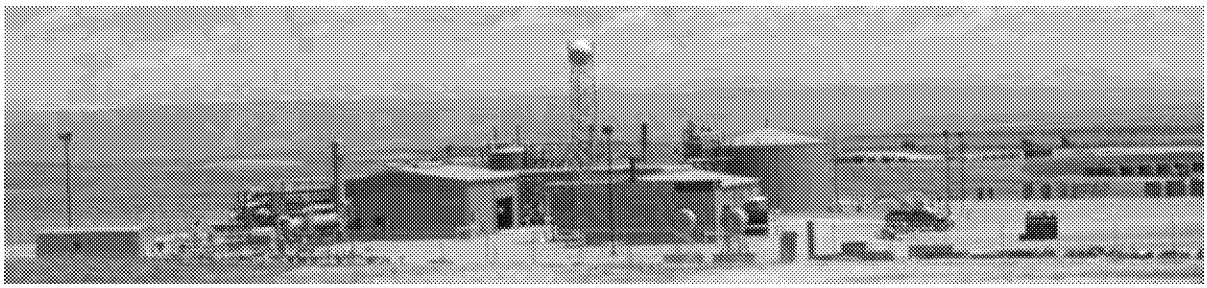

View of liquid storage site

1.5 Off Site Centralization of Production and Use of Liquids Gathering Systems

Using liquids gathering systems to collect and pipe produced fluids from each remote well location to a centralized production and collection facility situated more closely to a major county or state highway.

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.
- Volatile organic compounds from the absence of venting tanks at well pads.

Benefits:

- Creates fewer emission sources and consolidates control of emissions.
- Reduces haul truck trips and decreases associated dust and tailpipe emissions.
- Increased economic viability of capturing flash emissions and returning them to market rather than venting.

Where this can be applied:

- In fields that produce significant quantities of natural gas liquids.
- Where construction of pipelines is feasible and permissible.

Limitations:

- May not be feasible in some terrain conditions.
- May not be feasible if wells are too far apart.
- Concentrated emissions occur during construction of centralized facility.
- Requires installation and maintenance of pipelines.

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1.6 Telemetry and Well Automation

Using telemetry, rather than daily visits by operators, to remotely monitor and control production.

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Reduces truck trips and engine emissions.
- Decreases associated dust emissions.
- Increased safety.

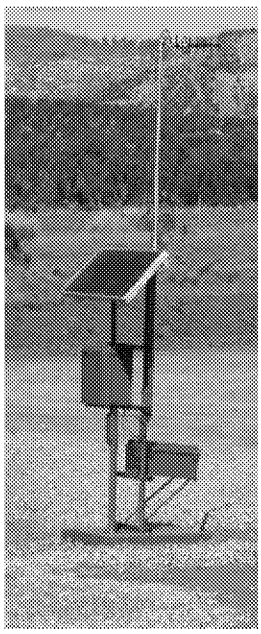
Where this can be applied:

- At least to some extent, can be applied to most projects.
- Subject to availability of licensed spectrum and bandwidth.

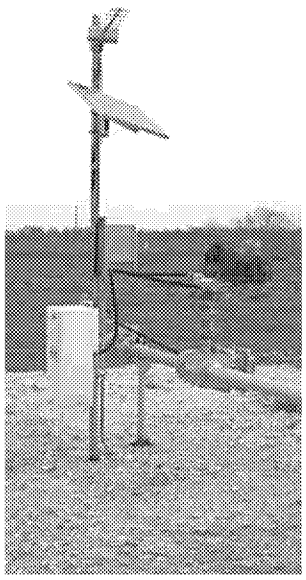
Limitations:

- May require application-specific development or adaptation.
- Training required.
- Specialized servicing.

Two meters with solar & telemetry



Valve with solar power and telemetry



Insrument box with solar panel and antenna

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1.7 Dust Suppression with Water

Reducing fugitive dust from vehicle traffic by applying water to unpaved roadways.

Watering truck

Emissions reduced:

- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Emission reduction; can greatly reduce dust near roadway and, to some extent, up to several miles away from roadway.
- May reduce road wear somewhat.
- Improved safety for drivers.
- Low initial cost.

Where this can be applied:

- Unpaved and partially paved roadways.
- At least to some extent, can be applied to most projects.

Limitations:

- Most effective with low traffic.
- Lasts only hours; requires frequent applications and maintenance.Availability of water in arid areas.
- Tailpipe emissions from vehicles making applications.
- Requires administrative authority for implementation and enforcement.

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1.8 Dust-Suppressant Mixtures

Reducing fugitive dust from vehicle traffic by applying dust suppressants such as magnesium chloride, calcium chloride, lignin sulfonate, and asphalt emulsions to unpaved roadways.

Emissions reduced:

- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

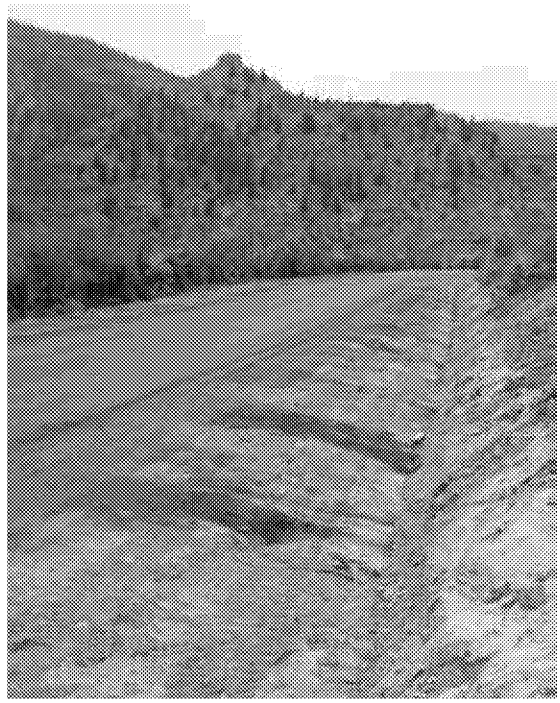
- Emission reduction; can greatly reduce dust near roadway and, to some extent, up to several miles away from roadway.
- Reduced road wear.
- Improved safety for drivers.
- Moderate initial cost.
- Lasts up to a year.
- Good for low-traffic roads.

Limitations:

- Higher cost than water.
- Requires periodic re-treatment and maintenance.
- Tailpipe emissions from vehicles making applications.
- Possible migration of treatment materials.
- Requires administrative authority for implementation and enforcement. Check with local authorities regarding the allowable use of specific dust suppressants.

Where this can be applied:

- Unpaved and partially paved roadways.
- At least to some extent, to most projects.



Road with dust suppressant

Paved roadway

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1.9 Road Sealing and Surfacing

Reducing fugitive dust from vehicle traffic by sealing or paving roadways using chip-seal, asphalt, or other road surfaces.

Emissions reduced:

- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Emission reduction; can greatly improve air quality near roadway and, to some extent, up to several miles away from roadway.
- Significantly reduced road wear and erosion of roadbed.
- Improved safety for drivers.
- Effective on high-traffic roads.
- Can withstand traffic for several years.

Where this can be applied:

- Unpaved or partially paved roadways.
- Where construction of permanent, paved roadways is feasible and permissible.

Limitations:

- High or very high initial cost; more cost-effective for roads with higher average daily traffic.
- Possible increase in multi-use traffic, with corresponding increases in tailpipe emissions.
- Fragmentation of the landscape.

Dust Control — Examples and Illustrations. Treated and untreated sections of road. Dust Suppressant – good reduction in dust. (Dust trail still visible where there was no treatment.)

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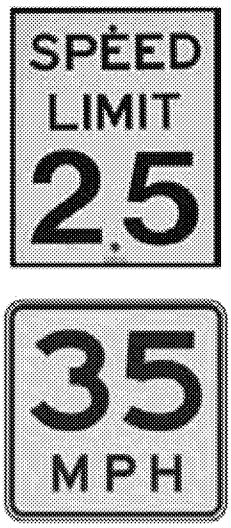
1.10 Administrative Controls on Roadways

Using reduced vehicle speeds to decrease fugitive dust.

The quantity of dust entrained increases with vehicle speed. In addition to the engineering controls of roadway emissions mentioned above, administrative controls may be feasible. These administrative controls include restricted access and, more frequently, speed limits. An issue of authority arises because access roads in and near public lands including national forests typically are public roads under state or local jurisdiction for traffic control. Accordingly, effectively applying these administrative controls will require coordination with these officials. In addition, oil and gas operators in a field can enforce speed limits as company policies.



Government suv making way for truck on unpaved road

Emissions reduced:

- PM_{10} and $PM_{2.5}$ from road dust.
- Tailpipe emissions including oxides of nitrogen, volatile organic compounds, carbon monoxide, and carbon dioxide due to improved fuel economy.

Benefits:

- Emission reduction.
- Reduced road wear.
- Improved safety.

Where this can be applied:

- At least to some extent, can be applied to most projects.
- Unpaved and partially paved roadways.
- On roads with high traffic and high dust potential.

Limitations:

- Requires authority to post speed limits.
- Requires effort to implement and enforce.

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1.11 Vanpooling

Using vans and buses to shuttle employees to the worksite, thereby reducing the number of vehicle trips.

A Vanpool Van

Emissions reduced:

- Tailpipe combustion emissions, including oxides of nitrogen.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Reduced overall vehicle emissions through reduction in vehicle miles traveled.
- Reduced road wear.
- Improved safety.

Where this can be applied:

- Most projects.
- Tasks not requiring movement of specialized or heavy equipment.
- Tasks occurring at fixed locations and where inter-site transportation can be arranged as needed.

Limitations:

- Requires exceptions for unscheduled trips.
- Costs of fleet operation and maintenance.

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1.12 Planning Documents

This section presents ideas on how to word sections of documents prepared under the National Environmental Policy Act (NEPA) or other planning documents. As indicated above, some emission reduction techniques used during the transport phase may develop as applicant- or operator-committed practices. This means that an applicant or operator will commit to using an emission-reducing technique, usually in writing. The commitment might or might not appear in NEPA documents.

Table 1 shows a partial list of emission reduction techniques and suggests some wording that could be used in describing them. Complete wording and more detailed versions of the suggestions below can be found on the web site of the Natural Resources Law Center (http://www.oilandgasbmps.org/browse.php?cat=1) and in other resources. Refer to the responsible state air quality control agency to ensure that any emission reduction strategies comply with regulations and permit requirements.

Table 1. Ideas for planning documents: transport phase.

Situation	Suggested Language
Develop an annual transportation plan.	*"Annual transportation planning will occur in coordination with efforts required for the project area."*
Carry out normal road maintenance activities.	*"Maintenance activities normally required include monitoring, blading, surface replacement, dust abatement, spot repairs, slide removal, ditch cleaning, culvert cleaning, litter cleanup, noxious weed control, and snow removal."*
Reduce traffic and surface disturbance and associated dust and tailpipe emissions.	*"Where practical and feasible, the operator commits to reduce traffic and surface disturbance and associated dust and tailpipe emissions by utilizing hub and spoke drilling and completion techniques, centralized fracturing operations, and centralized condensate and water collection."*
Implement dust suppression.	*"Implement dust suppression to minimize impacts to air, water, vegetation, and wildlife."*
In dust abatement, use no more water than necessary.	*"Only the water needed for abating dust should be applied."*
Apply dust suppressants to roads and stockpiles.	*"Operators will . . . apply water or suitable chemicals to keep dust in place on roads or material stockpiles."*
Control transportation-related dust throughout the duration of the project.	*"Operator responsibilities for preventive and corrective maintenance of roads in the project area would extend throughout the duration of the project and include blading; cleaning ditches and drainage facilities; dust abatement; control of noxious and invasive species; maintenance of fences, gates, and cattle guards; and other requirements as directed."*
Use gravel, water, or other dust suppressors.	*"The companies will use gravel, water, or other dust suppressors, as needed, to reduce dust associated with facility access roads."*
Surface roads and well locations.	*"Mitigation measures may include surfacing roads and well locations."*
Design roads to limit erosion and emission of fugitive dust.	*"The following standard practices limit the emission of fugitive dust: appropriate road design including shape, drainage and surface material to protect road bed from being eroded."*
Carpool.	*"Carpool to reduce vehicle numbers, dust, noise."*

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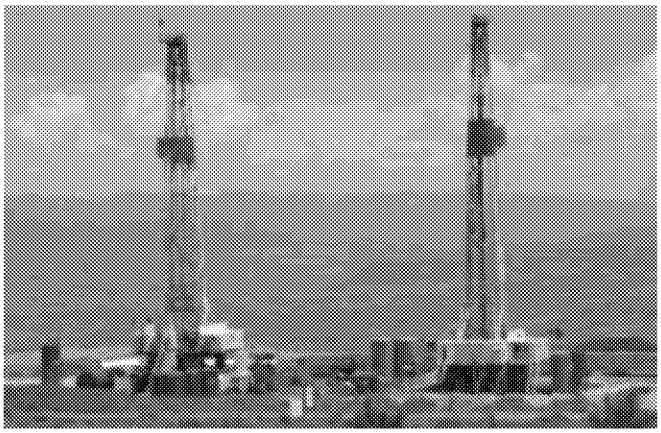
2.0 Air Resource Emission Reduction Techniques Drilling Phase



Twin rigs

The drilling phase also involves construction of roads, well pads, and other infrastructure in the project area. Emissions from earth-moving equipment; drilling engines; pits, tanks, and sumps; flares; and fugitive dust from roads and construction can occur during this phase. Although the groups of emission sources associated with construction are treated separately here, the construction phase often overlaps in time with the production phase. The likelihood that peak emissions will occur during development, production, or a period of overlap between the two phases will depend upon field characteristics such as well density; the depth and geological surroundings of the producing formation; the predominance of oil, wet gas, or dry gas in production; and the power needed for compression. It is important that State air quality control agencies be notified of planned operations during construction and drilling.

Representative Emission Reduction Techniques – Construction and Drilling

Emission reduction techniques that may apply during construction and drilling include selecting engines such as recently-available diesel engines with lower emissions or natural gas engines. Technology in this area is continually changing. For example, large nonroad diesel engines (over 750 horsepower) manufactured for sale in the U.S. through 2010 must meet emission standards known as tier 2. The same category of engines when manufactured from 2011 through 2014 must meet tier 4 transitional emission levels, and beginning in 2015 they must meet the final tier 4 standards. See section 2.1 below and the following Web site:

www.epa.gov/nonroad-diesel/regulations.htm

Venting releases methane and other hydrocarbons, including volatile organic compounds and hazardous air pollutants. Methane has approximately 21 times the global warming potential of carbon dioxide.

Flaring can be considered an emission reduction technique because it burns methane and other hydrocarbons that might otherwise be vented. Flaring natural gas is usually a better alternative than venting gas; however, some combustion products are also air pollutants. Flaring presents potential fire hazards and impacts to visibility, and citizen concerns may preclude the use of flaring at certain sites. As explained in section 2.3 below, flaring is usually regulated except in emergency circumstances and this document does not endorse flaring as a preferred technique. Well completion techniques with reduced emissions, sometimes referred to as "green completions," which should be considered as an alternative to flaring, are discussed further in section 2.4 below.

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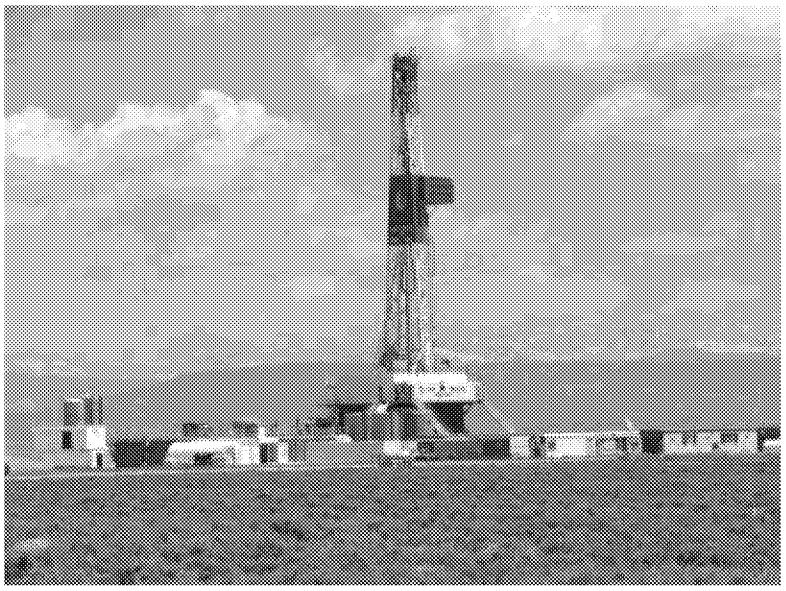
2.1 Cleaner Diesel Power



A Tier 2 diesel engine powers an electric motor to drill this well.

Reducing engine emissions by moving toward cleaner diesel (or compression-ignition) engines, such as engines meeting the tier 2, tier 4 transitional, or tier 4 final emission standards as they become available.

Emissions reduced:

- Oxides of nitrogen, carbon monoxide, PM_{10}, and $PM_{2.5}$.
- Carbon dioxide.
- Hydrocarbons.

Benefits:

- Uses engines manufactured to meet standards.
- Engines are to be available on a regulatory schedule.

Where this can be applied:

- Generator sets where diesel-electric drilling is to be used.
- Small and medium wellhead engines, if in use.
- May be considered for applications for permits to drill or records of decision; states typically do not regulate mobile-source drill rig engines.

Limitations:

- Cost of purchasing newly manufactured engines meeting current emission standards.
- Drillers operate under contract to applicants or field operators; any specification of engine type must flow through a contract.

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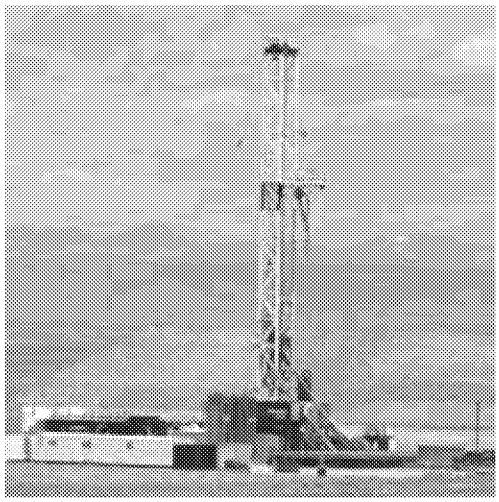
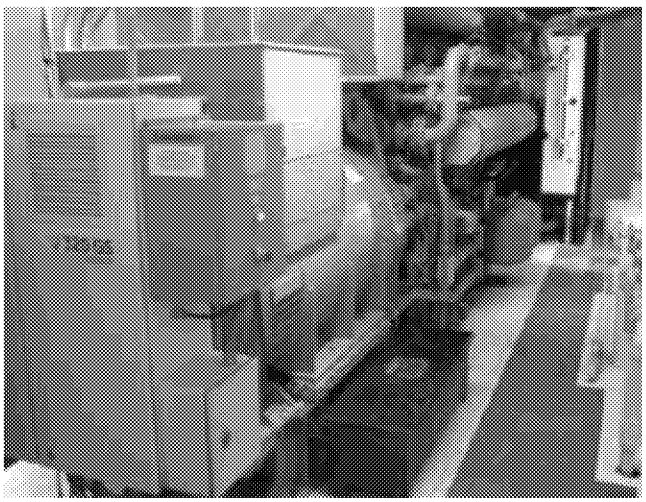
2.2 Natural Gas Power

Reducing engine emissions by using engines and generator sets fueled with natural gas.



Natural gas powered engines are typically cleaner than diesel engines and are the approximate equivalent of Tier 4 diesel engines.



Natural gas fueled engines power electric motors to drill this well.

Emissions reduced:

- Oxides of nitrogen, carbon monoxide, sulfur dioxide, PM_{10}, and $PM_{2.5}$.
- Hydrocarbons.

Benefits:

- Low emission characteristics.
- Fuel may be available on-site, following suitable processing.

Where this can be applied:

- In lieu of diesel-electric generator sets, as indicated by comparison of emission benefits and economics.
- Compressor stations.
- Small and medium wellhead engines, if in use.

Limitations:

- Requires selection of correct engines to meet power requirements.
- Cost of capital equipment.
- Drillers operate independently of applicants or field operators

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2.3 Well Completions – Flaring

Venting, as shown in this photograph, releases methane and other hydrocarbons.

A Flaring flame

Flaring of natural gas in order to avoid venting and prevent safety hazards.

In the past, flaring of natural gas was more commonplace in the United States. Regulations now prohibit this practice in many areas except in the case of emergency orders; check with the responsible authorities for regulations that apply in any specific area. This discussion does not recommend or endorse flaring aside from its use in emergency conditions. Instead, flaring is considered as an emission reduction technique relative to major venting (such as in well blowdown) and in contrast with the reduced-emission well completions covered in the next section. Where flaring and venting occur on public lands, these emissions should be tracked and recorded. More information can be found at:

www.epa.gov/gasstar/documents/installflares.pdf

Emissions reduced:

- Methane greenhouse gas emissions.
- To some extent, volatile organic compounds.

Benefits:

- Avoids extensive venting, which may be prohibited by state regulation.
- May cheaply and directly eliminate safety hazards posed by natural gas under pressure.

Where this can be applied:

- Where venting is impracticable (e.g., to prevent forceful venting of natural gas under emergency upset conditions) or prohibited (e.g., by state regulation).
- Where permitted, to flare natural gas considered to be economically irrecoverable at condensate wells or oil wells (an increasingly atypical circumstance).

Limitations:

- Emits oxides of nitrogen, carbon monoxide, and $PM_{2.5}$.
- Carbon dioxide (a less potent greenhouse gas than methane).
- Possibly emits volatile organic compounds that remain after incomplete combustion.
- Wastes valuable natural gas resources.
- Prohibited in some circumstances and jurisdictions.

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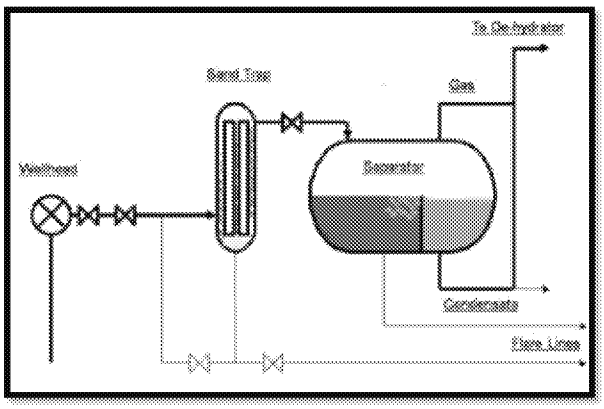
2.4 Reduced-Emission Well Completions



Green completion diagram

High-pressure separators

Using "green completions" to recapture a significant portion of product that would have been vented or flared. This type of device separates gas, sand, and water.

- High-pressure vessel separates sand from field gas.
- Gas vessel separates gas from water used for hydrologic fracturing.
- Gas is routed to sales line.
- Sand dumps to drill pit manually.
- Water dumps to media tanks automatically.
- Water is filtered and reused for future fracturing jobs

More information is available at:

www.epa.gov/gasstar/documents/greencompletions.pdf

Emissions reduced:

- Methane and volatile organic compounds (relative to venting).
- Oxides of nitrogen, carbon monoxide, and $PM_{2.5}$ (relative to flaring).

Benefits:

- Reduces methane and volatile organic compound emissions.
- Recovers product for sale.
- Improved overall safety at the well site.
- Recovers water for reuse.

Where this can be applied:

- Where safety permits recovery of gas (e.g., green completions are not inherently suitable to catastrophic releases of pressure such as blowouts).
- Where economics point toward using the technology.
- Where a sales line or other gas line with sufficient capacity is available to receive produced gas.
- Where natural gas liquids or, in some cases, crude oil accompany produced natural gas.

Limitations:

- Cost.
- Requires adequate reservoir pressure.
- Pressure of the gas must not exceed the rating of the sand trap or separator vessels.
- Gas must meet pipeline specifications.

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2.5 Planning Documents

This section presents ideas on how to word sections of NEPA documents or other planning documents. Emission reduction techniques during construction and drilling can also include applicant- or operator-committed practices. Forest Service offices will determine the role of operator-committed practices case by case. Normally this occurs during NEPA review, though additional operator-committed measures may be imposed or negotiated at the time of applications for permits to drill to address changed conditions or new information.

Table 2 shows a partial list of emission reduction techniques and suggests some wording that could be used in describing them. Complete wording and more detailed versions of the suggestions below can be found on the web site of the Natural Resources Law Center and in other resources. Learn about the available construction and drilling technology from the project proponents, and refer to the responsible state air quality control agency to ensure that any emission reduction strategies comply with regulations and permit requirements.

Situation	Suggested Language
Conduct a pre-construction field meeting prior to beginning any dirt work.	*"A pre-construction field meeting shall be conducted prior to beginning any dirt work approved under this plan of development."*
Implement fugitive dust control measures.	*"Develop a transportation plan to incorporate the following strategies: Implement fugitive dust control measures."*
Employ dust suppression to minimize impacts.	*"Employ dust suppression to minimize impacts to air, water, vegetation, and wildlife."*
Construct a flare pit on the well pad for drilling operations.	*"A flare pit will be constructed on the well pad for use during drilling operations. It will be located at least 125 feet from the well head and will be located down-wind from the prevailing winds."*
Institute necessary precautions to minimize fire hazards.	*"If this well is drilled during the fire season (June-October), the operator shall institute all necessary precautions to ensure that fire hazard is minimized, including but not limited to mowing vegetation on the access route(s) and well location(s), keeping firefighting equipment readily available when drilling, etc.".*"

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Situation	Suggested Language
Disturbed areas shall be reclaimed as early as possible to their original condition.	*"All disturbed areas affected by drilling or subsequent operations, except areas reasonably needed for production operations or for subsequent drilling operations to be commenced within twelve (12) months, shall be reclaimed as early and as nearly as practicable to their original condition or their final land use as designated by the surface owner and shall be maintained to control dust and minimize erosion to the extent practicable."*
Use Tier 3 (or Tier 4) engines or the equivalent.	*"By [date], the operator commits to achieve average drilling rig emissions equivalent to Tier 3 standards or better from 100 percent of drilling engines hired or run by the operator."*
Commit to vertically drill wells (in order to minimize emissions from drilling).	*"Wherever possible, the operator commits to vertically drill all of the natural gas wells in the project area in order to reduce associated oxides of nitrogen, sulfur dioxide, and PM_{10} emissions."*
Bring well-site portable equipment that cleans up most of initial produced gas to pipeline sales standards.	*"Green Completions -- Completions that are able to defer initial gas volumes through specialized equipment rather than flaring to atmosphere are a proactive effort that is beneficial for all elements of the environment. 'Green Completions' reduce noise levels, visual effects from flaring, reduce air pollution, and are an economic gain in many cases."*
Use water or chemicals to limit dust in demolition, construction, grading, or clearing.	*"The following standard practices limit the emission of fugitive dust: the use of water or chemicals to control dust in the demolition of structures, in construction operations, grading of roads, or clearing of land."*
Minimize emissions of particulate matter from well pad and road construction.	*"During construction, emissions of particulate matter from well pad and resource road construction will be minimized by application of water, or other dust suppressants, with at least [the specified level of] control efficiency. Roads and well locations constructed on soils susceptible to wind erosion could be appropriately surfaced or otherwise stabilized ..."*
Drill rigs powered by direct electrical power.	*"The operator is also evaluating the possibility of providing electrical service to power drilling rigs with direct electrical power, reducing emissions to negligible amounts."*

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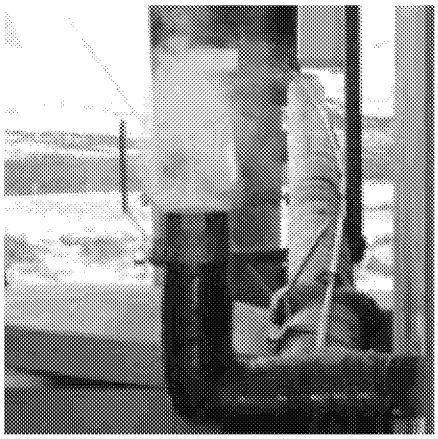
3.0 Air Resource Emission Reduction Techniques Production Phase

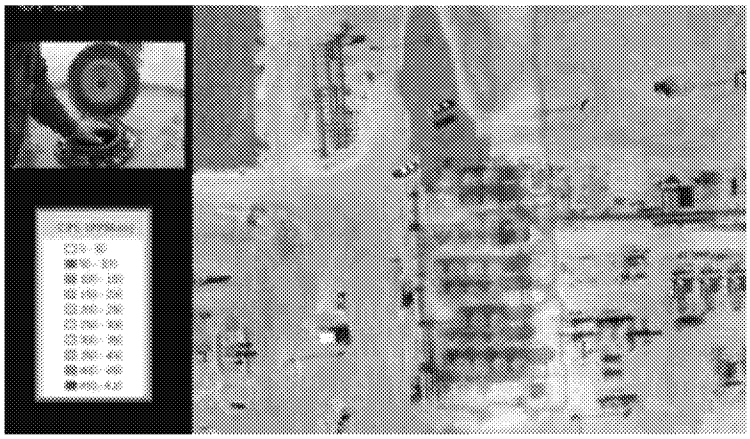
This section presents ideas on how to word sections of NEPA documents or other planning documents. Emission reduction techniques during construction and drilling can also include applicant- or operator-committed practices. Forest Service offices will determine the role of operator-committed practices case by case. Normally this occurs during NEPA review, though additional operator-committed measures may be imposed or negotiated at the time of applications for permits to drill to address changed conditions or new information.

Table 2 shows a partial list of emission reduction techniques and suggests some wording that could be used in describing them. Complete wording and more detailed versions of the suggestions below can be found on the web site of the Natural Resources Law Center and in other resources. Learn about the available construction and drilling technology from the project proponents, and refer to the responsible state air quality control agency to ensure that any emission reduction strategies comply with regulations and permit requirements.

- Release methane, a greenhouse gas (greenhouse gas) that has 21 times the global warming potential of carbon dioxide.
- Emit volatile organic compounds, which contribute to ozone formation.
- Emit hazardous air pollutants such as benzene, toluene, and xylene.
- Waste valuable natural gas resources.



Leaking ball valve



Aerial photo with imaging

Pneumatic devices convert gas pressure to mechanical energy. In this document, pneumatic devices are assumed to operate on natural gas except where natural gas is replaced with air as an emission reduction technique. Pneumatic devices such as liquid level controllers, pressure regulators, and valve controllers release natural gas into the atmosphere in normal operation.

On-site engines or turbines, whose combustion of fuel is another source of emissions, may be present to produce the power needed to move the hydrocarbon fluids. Storage vessels can emit vapors through working, standing breathing, and flash emissions and other direct emissions to the atmosphere. Although these sources of emissions may be subject to state permitting requirements, additional emission reduction techniques may need to be considered.

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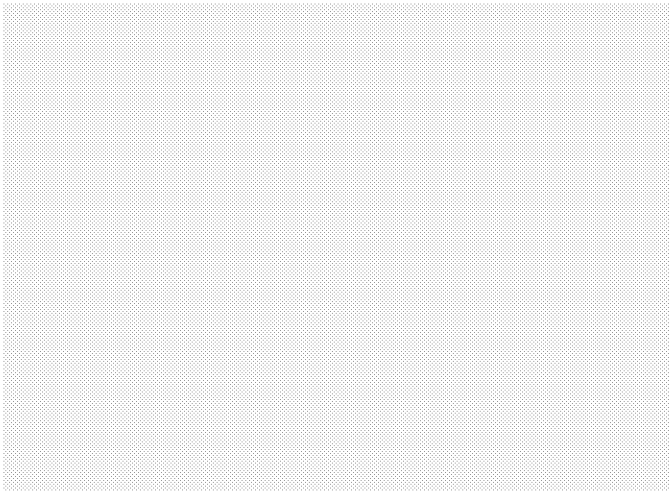

Metering Houses

Representative Emission Reduction Techniques – Production

Several techniques exist to control or recover hydrocarbon vapors and gases that could otherwise escape to the atmosphere. Operators have shown that the benefits of electrifying gas and oil fields can in some cases outweigh the disadvantages. Supplemental or alternative power sources can reduce emissions and can often operate with low maintenance in remote locations. Operators should also select engines with the best fuel requirements, power, and emission characteristics for individual field applications. Emission controls for engines, including large compressor engines, continue to evolve.

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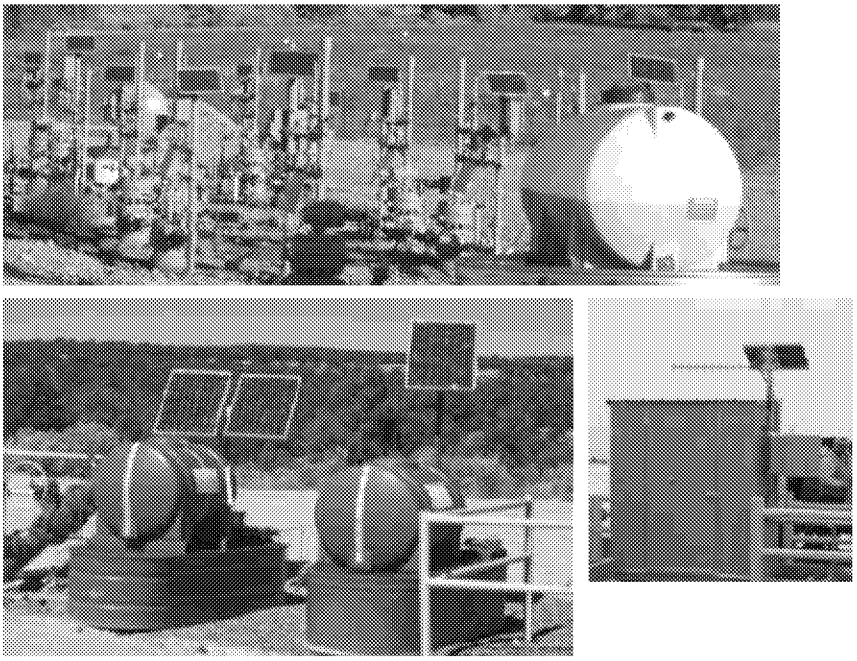
3.1 Solar Power

Using chemical pumps and well monitoring telemetry powered by solar panels.



Examples of solar-power at production facilities

More information is available in the presentation, Solar Power Applications for Methane Emission Mitigation:

www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland6.ppt

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Reduces truck trips, engine emissions, and methane emissions from gas pneumatic pumps.
- Silent operation.

Where this can be applied:

- At least to some extent, can be applied to most projects.
- At unshaded well and battery locations.

Limitations:

- Cost of capital equipment.
- Requires adequate number of panels to meet power requirements.
- Batteries, other electric storage, or alternative power sources needed during darkness.

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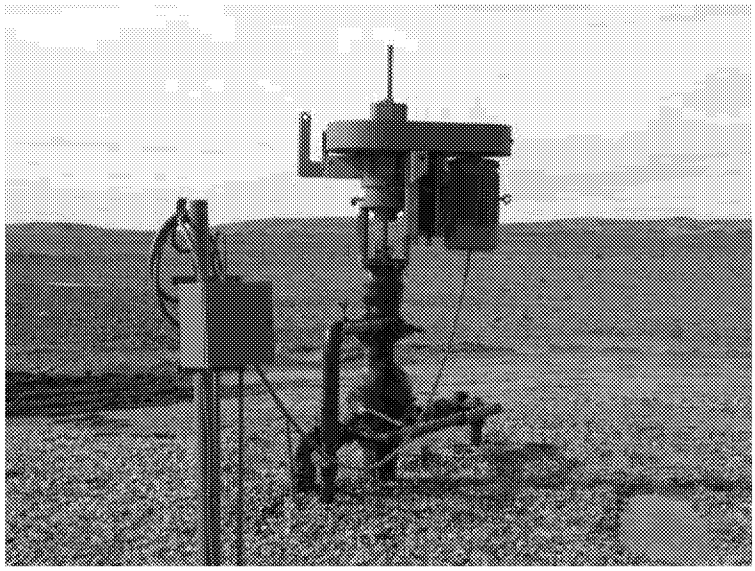
3.2 Electric Power

Using electricity from the nation's power grid is typically cleaner than using onsite diesel or natural gas engines to power drill rigs, compressors, and pumping units. However, overhead power lines may have wildlife or visual impacts.



Electric wellhead pump

Emissions reduced:

- Oxides of nitrogen from tailpipe emissions.
- Volatile organic compounds, carbon monoxide, and carbon dioxide from tailpipe emissions.
- PM_{10} and $PM_{2.5}$ from road dust.

Benefits:

- Standard rates available from utility.
- Eliminates in-field emissions from engines replaced by electric motors.
- Eliminates emissions from vehicles hauling product (e.g., condensate trucks).
- Reduces methane emissions from gas pneumatic pumps.
- May reduce overall traffic for maintenance-related trips.
- Silent operation.

Where this can be applied:

- Wherever grid power is available.

Limitations:

- Proximity to the grid.
- Increased load on grid with increased emissions at electric generating units.
- Power loss in transmission (line loss) proportional to the square of the current.
- Permitting requirements for new service.

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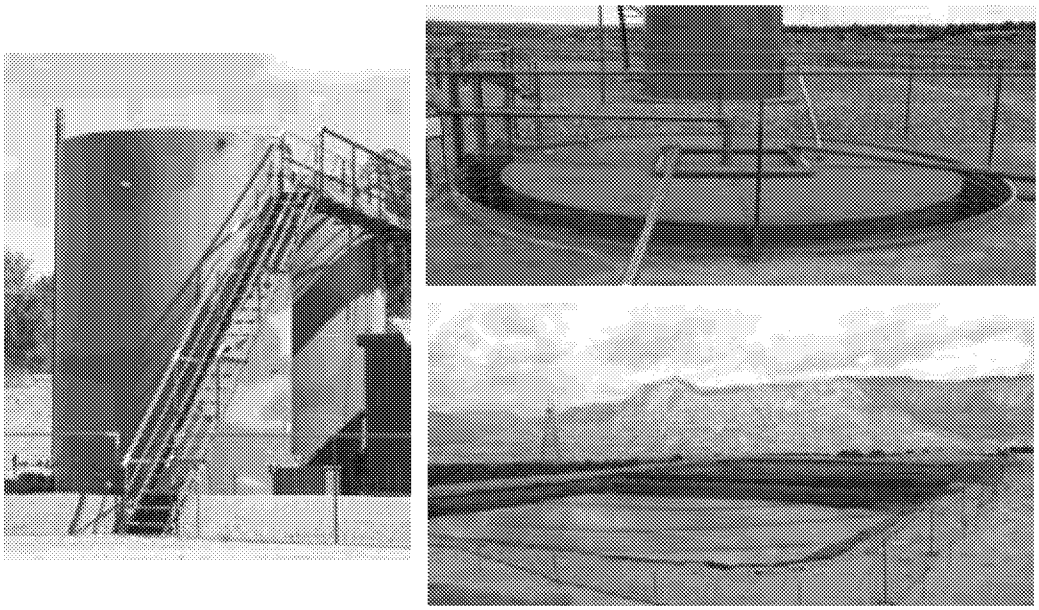
3.3 Tanks

Storing crude oil or condensate in enclosed tanks instead of open pits to reduce fugitive volatile organic compound emissions.



Examples of tanks and pits

Emissions reduced:

- Methane, volatile organic compounds, hazardous air pollutants

Benefits:

- Containment and control of product.
- Improved safety and wildlife protection.

Where this can be applied:

- Projects involving storage of liquid hydrocarbons.

Limitations:

- Construction, including access road.
- Cost of tank, fittings, and installation.
- Operation and maintenance costs.

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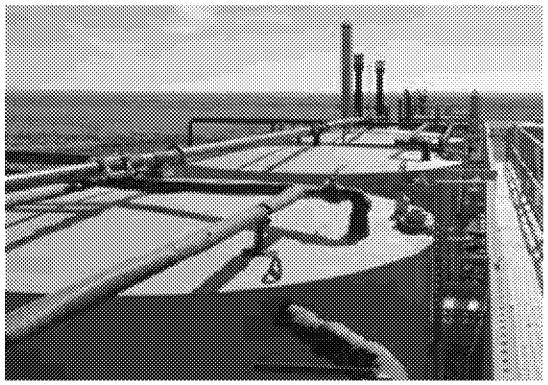
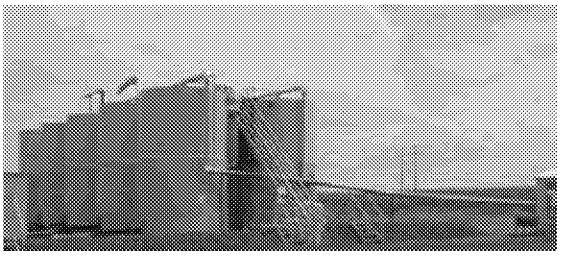
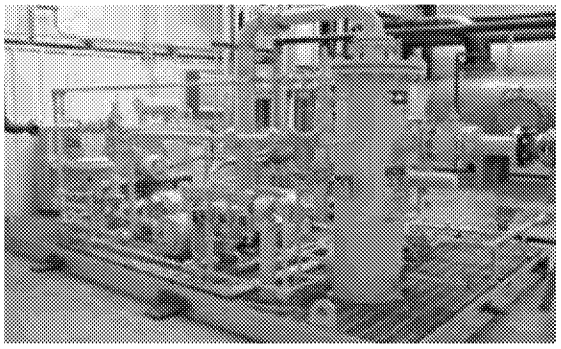
3.4 Vapor Recovery Units

Using vapor recovery units on oil, condensate, and produced water storage tanks reduces vented emissions of volatile organic compounds and recovers valuable hydrocarbon vapors for sale or use on site. Vapor recovery can readily capture 95 percent of the vapors that would be emitted from tanks if left uncontrolled, and capture efficiencies of virtually 100 percent are possible.







Examples of vapor recovery

More information is available at:

www.epa.gov/gasstar/documents/ll_final_vap.pdf

Emissions reduced:

- Methane, volatile organic compounds, hazardous air pollutants, and

Benefits:

- Recovery of product otherwise lost.
- Potential improvements in fire safety.

Where this can be applied:

- Projects involving storage of liquid hydrocarbons.
- On storage tanks, where pressures of hydrocarbons are at or near atmospheric pressure.
- Where oxygen can be excluded or explosive mixtures otherwise avoided.

Limitations:

- Cost-effectiveness varies with volume of hydrocarbons that can be recovered.
- Must be correctly engineered for safe operation.

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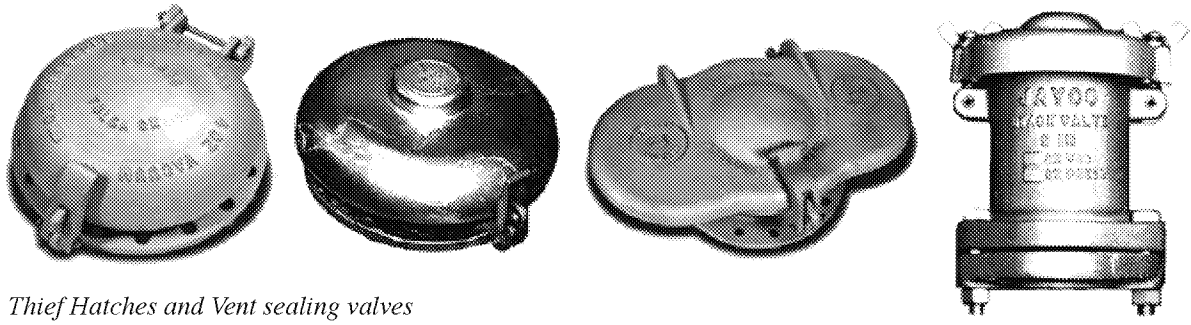
3.5 Hatches, Seals, and Valves

Using and maintaining proper hatches, seals, and valves to minimize volatile organic compound emissions.



Thief Hatches and Vent sealing valves

In order to minimize emissions and in addition to selecting appropriate hatches, seals, and valves relative to tank design, it is important to establish optimum pressure settings for this equipment.

Emissions reduced:

- Methane, volatile organic compounds, hazardous air pollutants, and

Benefits:

- Well-established technology.
- Moderate cost.

Where this can be applied:

- Projects involving storage of liquid hydrocarbons.
- On storage tanks, where pressures of hydrocarbons are at or near atmospheric pressure.
- Where oxygen can be excluded or explosive mixtures otherwise avoided.

Limitations:

- Must be selected appropriately for application.
- Will release hydrocarbon vapors at designed pressure and temperature.

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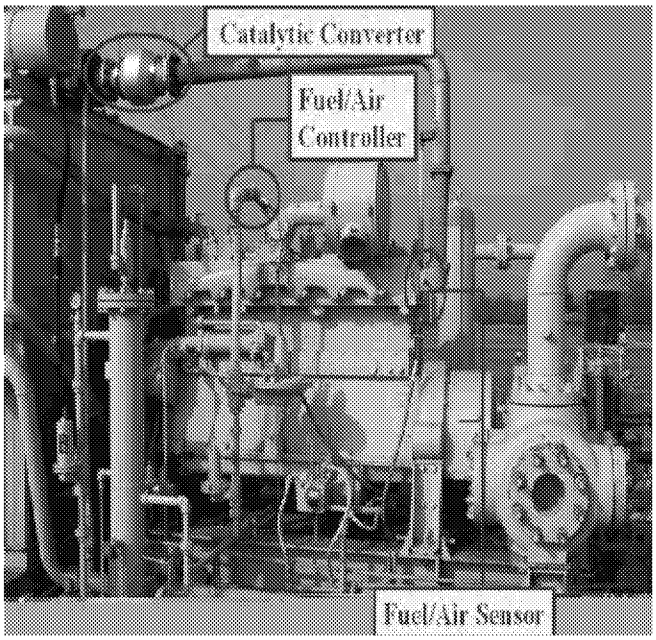
3.6 Controls for Compressor Engines

Improve emission controls on new or existing engines using a combination of techniques such as the following:

- Closed loop engine control,
- Selective catalytic reduction (covered as a stand-alone technique in section 3.7),
- System-installed power supply (solar powered, battery powered),
- Ultra-low sulfur diesel,
- Diesel particulate filter,
- After burner, and/or
- Other new technologies.



Controls on engine

Emissions reduced:

- Oxides of nitrogen, sulfur dioxide, carbon monoxide, and carbon dioxide.
- Some $PM_{2.5}$.

Benefits:

- Moderate cost, depending upon application and options selected.

Where this can be applied:

- Projects involving natural gas compression.
- Include control package as an option on new engines.
- Retrofit on existing engines.
- May be subject to regulatory approval by state.

Limitations:

- Availability by engine type and year of manufacture.

May require testing to confirm target emission rate is achieved.

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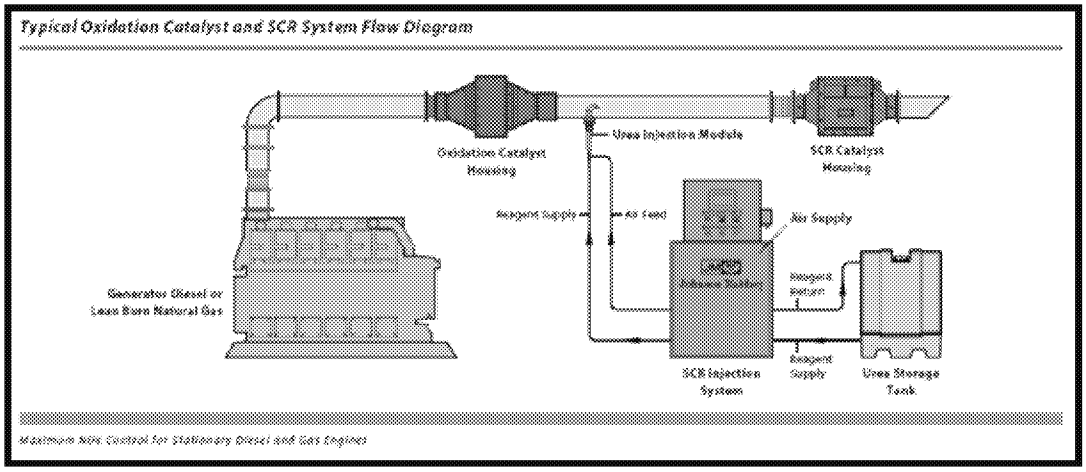
3.7 Selective Catalytic Reduction

Selective catalytic reduction works by injecting diesel exhaust fluid (DEF, a mixture of water and urea) into the exhaust. The DEF works with the heat of the exhaust and a catalytic converter to convert the oxides of nitrogen into nitrogen and water vapor. Commonly, a diesel particulate filter is included in the emission control package with selective catalytic reduction.



Emissions reduced:

- Oxides of nitrogen and
- $PM_{2.5}$ and hydrocarbons (if diesel particulate filter is included).

Benefits:

- Proven capability to reduce emissions.
- Feasibility of retrofitting.

Where this can be applied:

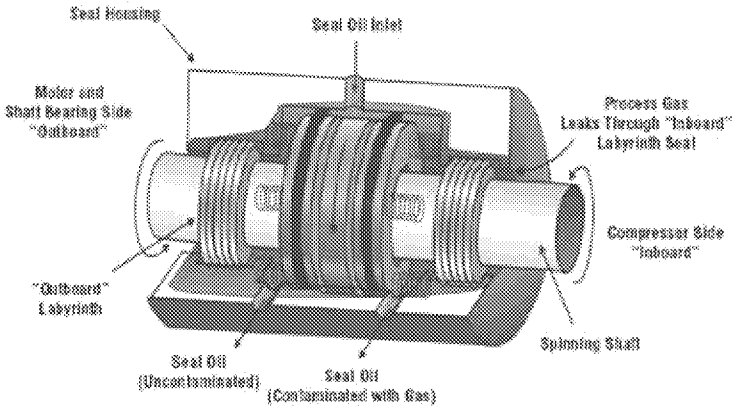
- Exhaust streams, e.g., on large engines, particularly where loads are steady or predictable.
- Where oxides of nitrogen emissions are of concern.

Limitations:

- Cost.
- Availability by for specific application.
- May require testing to confirm target emission rate is achieved.
- May be subject to regulatory approval by state.

3.8 Dry Seals in Centrifugal Compressors

Centrifugal wet seal compressor emissions from the seal oil degassing vent can be reduced by the replacement of wet seals with dry seals that emit less methane and have lower power requirements.



Centrifugal pump

More information can be found at:

www.epa.gov/gasstar/documents/ll_wetseals.pdf

Emissions reduced:

- Methane.
- Volatile organic compounds.

Benefits:

- Feasibility of retrofitting.

Where this can be applied:

- Natural gas compression where centrifugal compressors are in use.

Limitations:

- Relatively specialized applications.

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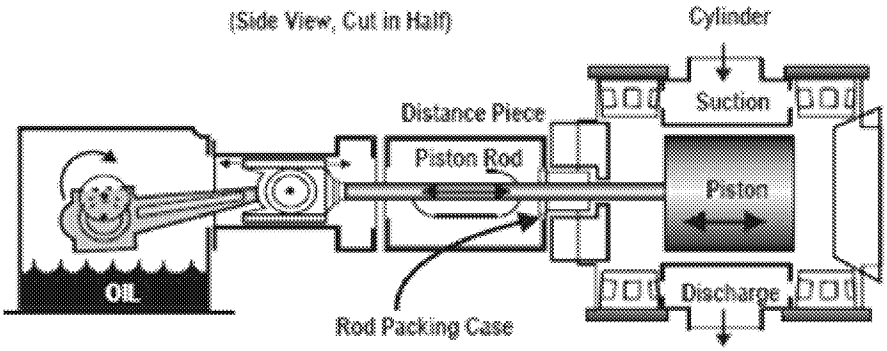
3.9 Packing Seals for Compressor Rods

The packing seals of reciprocating-rod compressors leak some gas by design. Emissions from rod packing can be reduced by the economic replacement of rod packing at frequent intervals as:

- Newly installed packing may leak 60 cubic feet per hour.
- Worn packing has been reported to leak up to 900 cubic feet per hour.



Reciprocating rod

More information is available at:

www.epa.gov/gasstar/documents/ll_rodpack.pdf

Emissions reduced:

- Methane.
- Volatile organic compounds.

Benefits:

- Feasibility of retrofitting.
- Proven capability to reduce emissions.

Where this can be applied:

- Natural gas compression where reciprocating-rod compressors are in use.

Limitations:

- Additional operational burden due to more frequent maintenance.
- Cost.

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3.10 Reduced-Emission Pneumatic Systems

To reduce emissions of methane and volatile organic compounds:

- Replace high-bleed devices with low-bleed.
- Retrofit bleed reduction kits on high-bleed devices.

Looking at controller

More information is available at:

www.epa.gov/gasstar/documents/ll_pneumatics.pdf

http://www.methanetomarkets.org/events/2005/oil-gas/docs/methanerec_pd_vru_dehy.pdf

Emissions reduced:

- Methane.
- Volatile organic compounds.

Benefits:

- Feasibility and ease of retrofitting with fairly quick cost recovery.
- Product recovery.
- Proven capability to reduce emissions.

Where this can be applied:

- Fields using natural gas in pneumatic controls.
- Where conversion to air-actuated or electric controls is economically infeasible.

Limitations:

- Accessibility of components.
- Continues to use natural gas.

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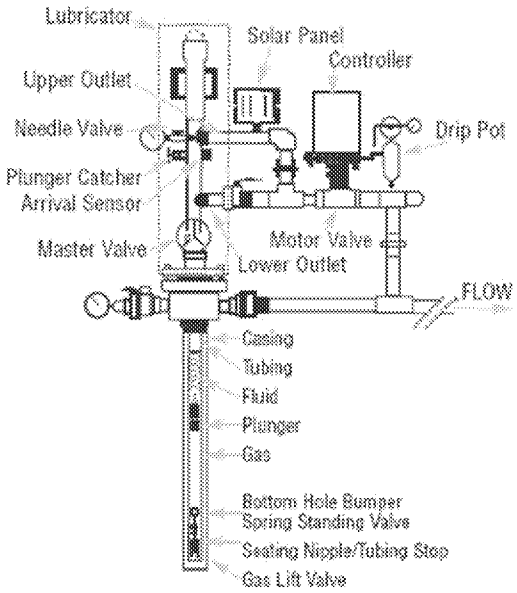
3.11 Plunger Lift Systems and Automated Systems in Gas Wells

Methane emissions from well blowdowns can be reduced by installing plunger lifts and smart automation systems which monitor well production parameters.



More information can be found at:

www.epa.gov/gasstar/documents/ll_plungerlift.pdf

www.epa.gov/gasstar/documents/smart_automation.pdf

Emissions reduced:

- Methane.
- Volatile organic compounds.

Benefits:

- Greater recovery of product.
- Operation and maintenance may be simplified.
- Potentially improved safety.

Where this can be applied:

- Typically in mature gas wells.
- Where down-well accumulation of liquids tends to compel blowdown to restore flow of natural gas.

Limitations:

- Cost-effectiveness.
- Relatively specialized applications.

3.12 Planning Documents

As in the preceding parts of this document, the section on air resource planning presents a partial list of ideas on the wording of planning documents. Considering field-specific conditions and continually developing technology, applicant- or operator-committed emission reduction techniques can play a particularly important role in the production phase. It is equally important to discuss these techniques with the operators or applicants. Many of the emissions in the production phase originate with stationary sources; accordingly, it is essential to refer to the responsible state air quality control agency to ensure that any emission reduction strategies comply with regulations and permit requirements.

As an illustration of field-specific challenges, table 3 below suggests wording on the possible use of desiccant dehydrators in place of glycol dehydrators. Some desiccant dehydrators may present problems in cold climates, depending upon the volume of water produced. However, other low-emission dehydrators are also available. Decisions about selecting a specific piece of equipment will depend on such factors as performance, capacity, and power requirements as well as the potential for emission reductions.

Table 3 shows a partial list of emission reduction techniques and suggests some wording that could be used in describing them. Complete wording and more detailed versions of the suggestions below can be found on the web site of the Natural Resources Law Center and in other resources.

Table 3. Ideas for planning documents: production phase.

Situation	Suggested Language
Require natural gas-fired engines for compressors and generators.	*"The air quality objectives for the proposed action include … requiring natural gas-fired engines for compressors and generators, except in areas with sensitive resources, including people, where noise is an issue."*
Install catalytic converters.	*"Install catalytic converters to minimize emissions."*
Replace gas starters with air.	*"Engines for compressors, generators, and pumps are often started using small gas-expansion turbines. Pressurized gas expanded across the starter turbine rotates the engine for startup, and then vents to the atmosphere. Replacing the natural gas with compressed air will eliminate this source of methane emissions."*
Install electric starters.	*"Gas-expansion starter turbines on compressors, generators, and pumps can also be replaced by electric starter motors, similar to an automobile engine starter."*
Convert gas-driven chemical pumps to instrument air.	*"Replacing natural gas with instrument air to drive the glycol circulation and chemical-transfer pumps increases operational efficiency, decreases maintenance costs, and reduces emissions of methane, volatile organic compounds, and hazardous air pollutants."*

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Situation	Suggested Language
Convert gas pneumatic controls to instrument air.	*"Converting natural-gas-powered pneumatic control systems to compressed-instrument-air systems eliminates 100 percent of the methane emission from valve controllers and may also be used to eliminate methane emissions from pneumatic pumps and compressor-engine pneumatic starters."*
Convert gas pneumatic controls to mechanical controls.	*"The most common mechanical control device is a level controller, which controls the position of a drain valve by mechanical linkages to the position of a liquid-level float. The mechanical device eliminates both the process controller bleed and the valve-actuation vent emissions. Mechanical controls can be used where the process measurement is close to the flow control valve, with a savings of 500 Mcf/yr per controller."*
Use low-bleed pneumatic controllers.	*"All new and replaced pneumatic controllers will be a no-bleed or low-bleed design."*
Replace glycol dehydrators with desiccant dehydrators.	*"Glycol dehydrators vent methane, volatile organic compounds, and hazardous air pollutants to the atmosphere from the glycol regenerator, bleed natural gas from pneumatic control devices, and burn natural gas in the glycol reboiler. Replacing glycol dehydrators with desiccant dehydrators reduces methane, volatile organic compound, and hazardous air pollutant, emissions by 99 percent and saves fuel gas for sales."*
Eliminate well-site dehydrators.	*Operator "will not use well-site dehydrators."*
Reroute glycol skimmer gas.	*"Some glycol dehydrators have glycol still condensers and condensate separators to recover natural gas liquids and reduce volatile organic compound and hazardous air pollutant emissions. Rerouting the skimmer gas to the reboiler firebox or other low-pressure fuel-gas systems reduces methane emissions and saves fuel. Using glycol skimmer gas as a fuel directly offsets use of saleable gas, increasing product revenues and quickly paying back the low capital, operating, and maintenance costs."*
Prevent emissions from storage tanks.	*"Emission controls will be utilized on all condensate storage batteries with emissions greater than five tons per year" "At a minimum. The applied control technology must be capable of reducing emissions by 95 percent."*

Situation	Suggested Language
Recover gas during condensate loading using recycle lines.	*"Condensate, when transferred from storage into tank trucks, can generate significant volumes of gas caused by pressure and temperature changes and evaporation. This gas is typically vented to the atmosphere but can be contained by connecting the tank truck vent to the condensate storage tank with a vapor-recovery system."*
Calculate an economic replacement threshold for compressor-rod packing systems.	*"Gas leaks from compressor rods represent one of the largest sources of emissions at natural gas compressor stations. All packing systems leak under normal conditions. A simple calculation using company-specific financial objectives and monitoring data can determine emissions levels at which it is cost-effective to replace rings and rods."*
Decrease heater-treater temperature.	*"Heater-treaters use thermal, mechanical, gravitational, and chemical methods to break emulsions and separate crude oil from water. Elevated temperature is effective in lowering oil viscosity and promoting phase separation, but requires fuel gas and causes volatile hydrocarbons in the oil to vaporize and vent. Heater-treater temperature settings at remote sites may be higher than necessary, resulting in increased methane and volatile organic compound emissions."*
Reduce emissions from process heaters.	*"Use low-oxides of nitrogen burners in process heaters."*

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4.0 Air Resource Emission Reduction Techniques

Monitoring and Maintenance

Agreement on reasonable emission reduction techniques can produce a plan of development that will prevent unnecessary emissions to the atmosphere. As development proceeds, monitoring, enforcement by regulatory and land management agencies, and record-keeping ensure that mitigation is effectively implemented. By introducing technology and practices designed to reduce emissions, applicants and operators can reduce overall emissions from a project. Once repaired, most emissions linked to equipment problems tend to stop; therefore, timely maintenance and repair can significantly reduce emissions. This part of the paper presents techniques that apply to monitoring and maintenance.

While most closely associated with production, monitoring and maintenance apply to all phases of development. As discussed above, consultation with air quality experts of the state air quality authority regarding monitoring and maintenance is essential.

Spraying tank

Highlights of Monitoring and Maintenance

Examples of monitoring and maintenance activities: directed inspection and maintenance, infrared leak detection and ambient quality monitoring.

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4.1 Directed Inspection and Maintenance and Infrared Leak Detection (DI&M)

Fugitive gas leaks can be reduced by implementing a DI&M Program which identifies and cost effectively fixes fugitive gas leaks using:

- Leak Detection
  - Infrared Camera
  - Organic Vapor Analyzer
  - Soap Solution
  - Ultrasonic Leak Detectors
- Measurement
  - Calibrated Bagging
  - Rotameters
  - High Volume Sampler

Leak-testing a component

More information can be found at:

www.epa.gov/gasstar/documents/03_dim_in_gas_production_facilities.pdf

Emissions reduced:

- Methane.
- Volatile organic compounds.

Benefits:

- Detects emissions by remote sensing.
- Ease of use following minimal training.

Where this can be applied:

- Most projects involving hydrocarbon production and treatment.
- In order to detect leaking process components, including valves, flanges, and connections.
- Sealing mechanisms, such as on reciprocating rods and pump seals.
- Hatches and seals on tanks.

Limitations:

- No direct quantification of emission rates.
- Most effective when used in a structured program requiring oversight and management.
- Cost of purchase and repair of instrumentation.

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4.2 Air Quality Monitoring

Using air monitoring for:

1. Monitoring current and modeling future air quality conditions.
2. Designing emission control strategies.
3. Reviewing monitoring data and adapting to findings:
   - Adjusting development rates, timing, and places of development.
   - Refining mitigation measures

Emissions reduced:

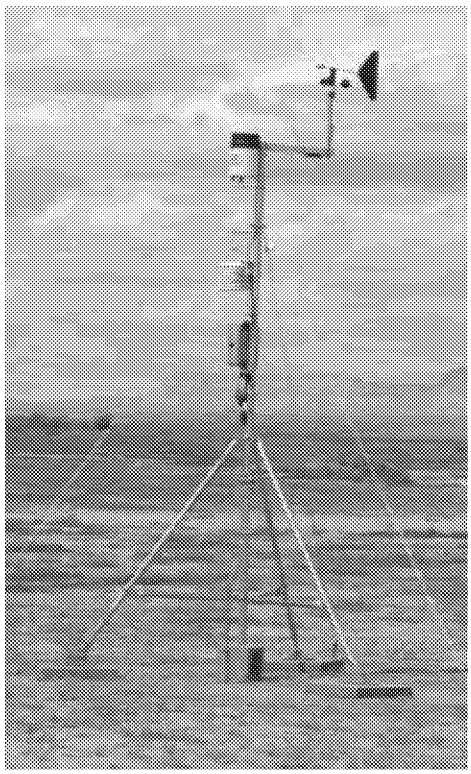
- Indirectly, emissions of any pollutant of concern which can be monitored.

Benefits:

- Gives knowledge of concentrations and trends in the ambient air.
- Produces information that can be shared with the public.
- Supports air dispersion modeling efforts.

Where this can be applied:

- Large projects or project areas where adequate funding can be arranged.



Portable metorological station

- At a location that is representative under the monitoring objective(s).
- In areas where Federal Land Managers and regulatory agencies concur that monitoring is warranted.
- Where land access, possibly long-term, can be gained.
- Where electric power is available, unless passive sampling or monitoring using low-power equipment can suffice.
- In the "ambient air," as defined for regulatory purposes, if required.

Limitations:

- Cost.
- Time required in order to collect and report data.
- Difficulty of meeting expectations of data users.
- Does not directly control or reduce emissions.

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4.3 Planning Documents

Downstream oil and gas processing facilities are normally subject to more regulations covering leak detection and repair than upstream production. However, inspection rules also apply to some upstream units and the operators should refer to state regulatory agencies about their specific situations. Although it cannot directly measure source-specific emission rates, ambient air monitoring can support tracking of regional trends. The lower the emissions per unit of equipment, the more likely that oil and gas development may proceed without jeopardizing air quality standards.

Table 4 builds on the examples above with a partial list of emission reduction techniques and suggests some wording that could be used in describing them. Complete wording and more detailed versions of the suggestions below can be found on the web site of the Natural Resources Law Center and in other resources.

Table 4. Ideas for planning documents: monitoring and maintenance.

Situation	Suggested Language
Begin a directed inspection and maintenance at compressor Stations.	*"Fluctuations in pressure, temperature, and mechanical stresses on pipeline components (such as valves and seals) eventually cause them to leak. A directed inspection and maintenance program concentrates on components such as valve packing, pneumatic controllers, open-ended lines, blowdown lines, pneumatic engine-starter motors, and pressure-relief valves, which are prone to large leaks that are cost-effective to find and fix."*
Inspect flowlines annually.	*"Annual flowline inspection and a regular leak-repair schedule will reduce gas losses and prevent small leaks from growing into major leaks. Leaks in buried flow lines may be detected by using an ultrasound detector, or infrared imaging, or through the temporary introduction of odorant into the gas stream"*
Use ultrasound to identify leaks.	*"Some of the hardest leaks to find, and therefore among the largest leaks, are shutoff valves on open-ended lines that vent through an elevated stack. Ultrasound leak detectors are tuned to detect the high-frequency sounds associated with gas flowing through a valve that is not tightly closed. Lower-frequency background noises are filtered out. The magnitude of the sound corresponds to the magnitude of the leak. Ultrasound detectors can be applied to all in-service shutoff valves and pressure-relief, blowdown, starter-motor, and unit isolation valves."*
Optical leak imaging.	*Operator "will employ forward-looking infrared (FLIR) methodology for detecting fugitive emissions (volatile organic compound and hazardous air pollutant reduction)."*

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5.0 For More Information on Emission Reduction Techniques

EPA Natural Gas STAR Program

http://www.epa.gov/gasstar/tools/recommended.html

California Air Resources Board's Clearinghouse

http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm

Four Corners Air Quality Group

http://www.nmenv.state.nm.us/aqb/4C/

Natural Resources Law Center

http://www.oilandgasbmps.org/browse.php?cat=1

Four Corners Air Quality Task Force, Report of Mitigation Options

http://www.nmenv.state.nm.us/aqb/4C/TaskForceReport.html

BLM Oil and Gas BMP Powerpoint

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices/technical_information.html

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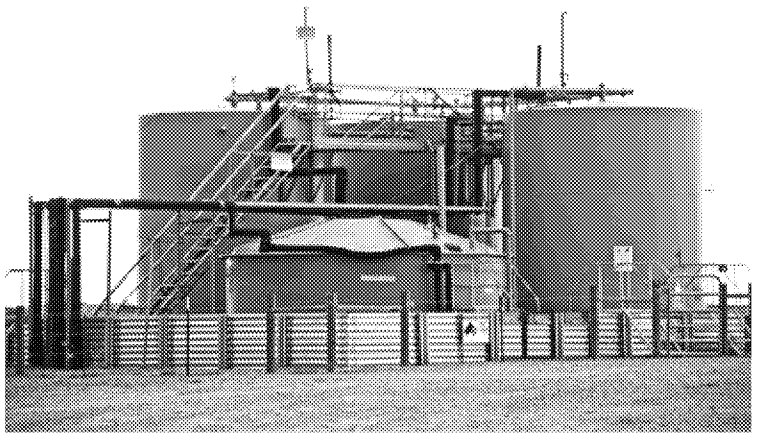
Estimating Air Emissions from Oil and Gas Operations

December 29, 2015

Everyday environmental professionals are estimating emissions from oil and gas production facilities and supplying data that will be used to make decisions that cost companies money. Typically, the estimation is done using a combination of methods as described in this blog. Notably, this data affects the following:

- Type of air pollution controls installed.
- Air permit type that applies based on emission source or facility total emissions such as a minor source or a major source.
- Greenhouse gas (GHG) annual reporting requirements such as the mandatory EPA reporting and voluntary industry reporting.
- Criteria and hazardous air pollutant (HAP) annual reporting requirements to state agencies.



Why is it important to determine emissions as accurately as possible?

- Overestimating facility emissions may trigger major source Part 70/Title V air permitting or require mandatory greenhouse gas (GHG) reporting under 40 CFR 98. Also, keeping emissions as low as possible can help a facility qualify for a "general" minor source air permit (e.g., TCEQ PBR). General permits have a much shorter wait time for approval than individual minor source air permits.
- Underestimating emissions may cause compliance issues if a future required stack test (e.g., NSPS JJJJ for engines) yields a higher emission rate than used in the air permit or required by an applicable standard. Typically, a site specific source/stack test will be more reliable than a published emission factor.
- Companies operating major sources pay air pollutant emission fees based on actual air emissions of criteria pollutants and HAP emissions. Many expect that in the near future fees will be assessed on GHG emissions – possibly for retroactive past GHG emissions.

Methods Used

Typical methods used to estimate air emissions include:

1. Emission factors and equations supplied by a regulatory agency. The U.S. Environmental Protection Agency (EPA) publishes the most widely used source known as AP-42, Compilation of Air Pollutant Emission Factors.
2. Emission factors and equations required by the USEPA for GHG reporting under 40 CFR Subpart 98.
3. Emission factors generated by a manufacturer or supplier. Most engine and catalytic converter suppliers will have published emission data for their products.
4. Source/emission testing. This includes stack testing engines and vent gas measurement and chemical analysis. Many operators prefer direct measurement of vent gas from storage tanks.
5. Process simulation software from regulatory agencies, trade organizations and facility process design simulators.
6. Material balance calculations. Use the difference between inlet mass and outlet mass of a product to estimate losses to the atmosphere for volatile chemicals and particulate matter.
7. Stack testing of engines and enclosed combustors.
8. Direct measurement by metering gas volumes and gas chemical analysis. The ideal gas law relationships can be used with the direct measurement data to calculate mass of natural gas components vented or combusted.

Emissions data from a source test, process simulator, material balance and metered volumes are usually expressed in units of lbs of pollutant per hour. This data can be converted to a site specific emission factor by expressing the emissions data as the mass of emissions per unit of activity.

For example, HY-BON/EDI's IQR services measure the volume of gas vented from a storage tank during a 24-hour period, then sample and chemically analyze the vent gas to yield a lbs of VOC per hour rate. Combining this data with the oil production rate (average barrels per day) allows the user to calculate an emission factor based on the lbs of VOC vented per barrel of oil throughput in the storage tank.

Emission Factor Formulas

The general equation for emissions estimation using emission factors is:

E = (A)-(EF)-(1-ER/100)

where:

E = emissions

A = activity rate (e.g., BOPD, amount of fuel burned per hour, hours operated, volume of gas vented)

EF = emission factor (e.g., lbs VOC per standard cubic feet natural gas vented)

ER = overall emission reduction efficiency, % - if emission controls are operating

AP-42 Emission Factor Ratings

AP-42 supplies "Ratings" for emission factors that range from A through E and Unrated, "U". An "A" rating being "Excellent" considered the most favorable factor. The rating are based on source test data taken from facilities in the industry population. The larger number of samples across a specific source type, the higher the rating.

Due to the large variation in emissions from internal combustion engine and changing emissions standards, AP-42 emission factors may not be the best choice if a stack test will be required.

Potential Issues When Calculating Air Emissions

- Using the wrong emission factor based on the process or emission source type. For example, using emission factors for a 2-cycle, lean burn spark ignition engine for a 4-cycle, lean burn spark ignition engine based upon a lack of enough data for the engine operating.
- Changes in published EPA and state regulatory emission factors can require a facility to recalculate emissions and comply with applicable standards based on use of the new/updated emission factor.
- Changes in facility crude oil, condensate and natural gas chemical makeup based on new well production.
- For process simulations, use of inaccurate data inputs (e.g., operating pressures and temperatures) or use of data not representative (e.g., gas analyses) of the process or products produced.
- Applying a site specific emission factor to another facility that is not representative of operating parameters, fuel used or chemical makeup of the crude oil, condensate or natural gas produced.
- Underestimating or overestimating the emissions reduction from an emission control device.

Air Pollutants calculated

- Criteria pollutants: NOx, CO, VOC, SO2, PM2.5, PM10
- Hazardous air pollutants (HAP): benzene, toluene, ethylbenzene, xylenes, n-hexane
- Greenhouse gases (GHG): CO2, methane, N2O

O&G Emission Sources and Emission Factors

Emission Source Type	Typical Sources for Emission Factors and Estimation Methods
Amine gas sweetening units	AmineCalc; process simulators; direct measurement
Crude oil, condensate, produced water, volatile organic liquids storage tanks	AP-42 Chapter 7 and EPA TANKS4 program; process simulators; direct measurement
Crude oil and condensate loading - trucks, barges, ships	Ap-42, Chapter 5
Flares and enclosed combustors	AP-42, Chapter 13; state regulatory agencies (e.g., TCEQ)
Fugitive sources from valves, flanges, connections, pump and compressor seals	AP-42, Chapter 5; API Documents 4638, 4589, 4615; 40 CFR 98 Subpart W for GHGs; state agencies
Fugitive dust/particulate matter	AP-42, Chapter 13; state regulatory agencies
Glycol dehydrators	GRI-GLYCalc; process simulators
Heater treaters, line heaters, reboilers	AP-42, Chapter 1
Internal combustion engines - reciprocating, turbines	Vendor data; AP-42 Chapter 3; stack testing
Pneumatic pumps, controllers that use natural gas	Vendor data; 40 CFR 98 Subpart W for GHGs
Venting of natural gas from wells and facility processes	Metered or calculated volume, gas analysis and ideal gas law equations

Resources for Air Emission Estimation

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Below is a list of commonly used resources for emission factors and estimation methods for oil and gas industry stationary sources.

Criteria and Hazardous Air Pollutants

- USEPA Technology Transfer Network (TTN) includes the CHIEF Clearinghouse for Inventories & Emissions Factors. Under CHIEF can be found emission factors and estimation tools (software) to calculate air emissions.
- AP-42, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Fifth Edition
- TANKS software – based on methods in AP-42 Chapter 7: Liquid Storage Tanks. TANKS only includes standing and working losses – no flashing losses calculated.
- E&P TANKS (API Publication 4697) by American Petroleum Institute is a software that uses site-specific information to estimate emission from petroleum production storage tanks. Includes standing, working and flash losses.
- WebFIRE – a database management system containing EPA's recommended emission estimation factors for criteria and hazardous air pollutants
- GRI-GLYCalc software – program for estimating air emissions from glycol units using triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
- Oil and gas process simulators such as Aspen HYSYS, Bryan Research & Engineering, Inc. ProMAX, Virtual Materials Group VGM.
- AMINECalc Version 1.0 – Amine Unit Emissions Model (API Publication 4679)

Greenhouse Gases

- 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting
- Compendium of Greenhouse Gas emissions Methodologies for the Oil and Gas Industry, American Petroleum Institute (2009)

Concerned About Venting of Natural Gas?

HY-BON/EDI is your expert at vent gas management. We use our IQR Survey to help O&G operators find leaks, quantify storage tank emissions and rectify the emissions. Our IQR services and VRUs help a company stay in compliance with their air permits and air emission reporting requirements.

Our products and services can also make you money by recovering valuable vent gas that may be lost to the atmosphere or sent to flare to be burned.

Let HY-BON/EDI take away some of your air pollution concerns so your facilities stay in compliance.

vent gas

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Natural Gas STAR Technology Transfer Pre-Conference Workshop

Roger Fernandez, U.S. EPA
Natural Gas STAR Program / Global Methane Initiative

September 24, 2013

SHALE INSIGHT 2013
PENNSYLVANIA CONVENTION CENTER
PHILADELPHIA, PA
SEPTEMBER 25-26

NaturalGas
EPA POLLUTION PREVENTER

Natural Gas STAR Technology Transfer Pre-Conference Workshop

Methane Emissions Reduction Opportunities during Natural Gas Production

Leonard Nelms, Ph.D.

Principal Air Program Manager

Tetra Tech, Inc.

September 24, 2013

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Introduction

- Overview of natural gas production process
- Drivers for implementing methane reduction measures
- Significant sources of methane (natural gas) releases
- Common emission control technologies employed
- Emission reduction successes
- Remaining challenges
- Summary

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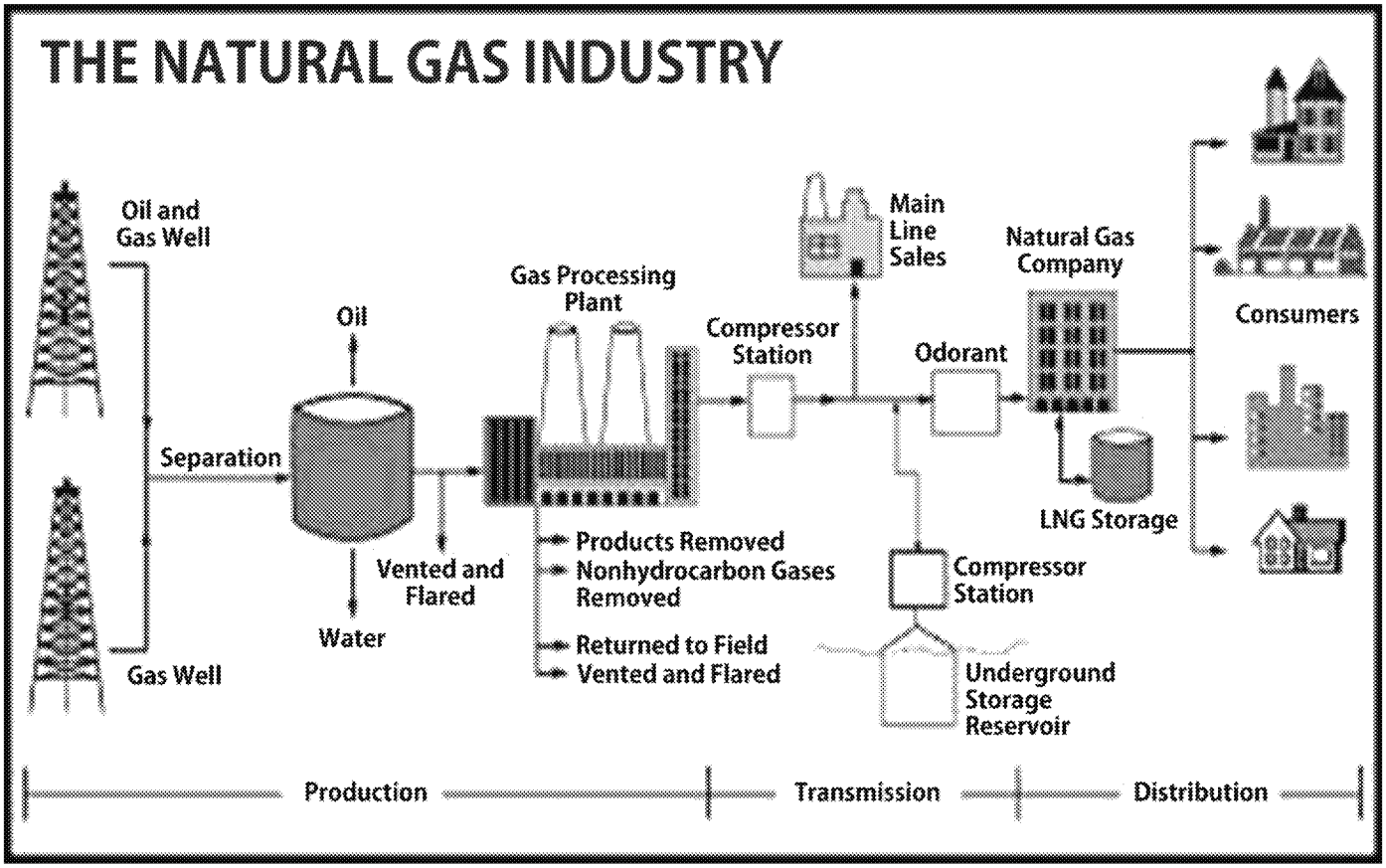
Overview of Natural Gas Production



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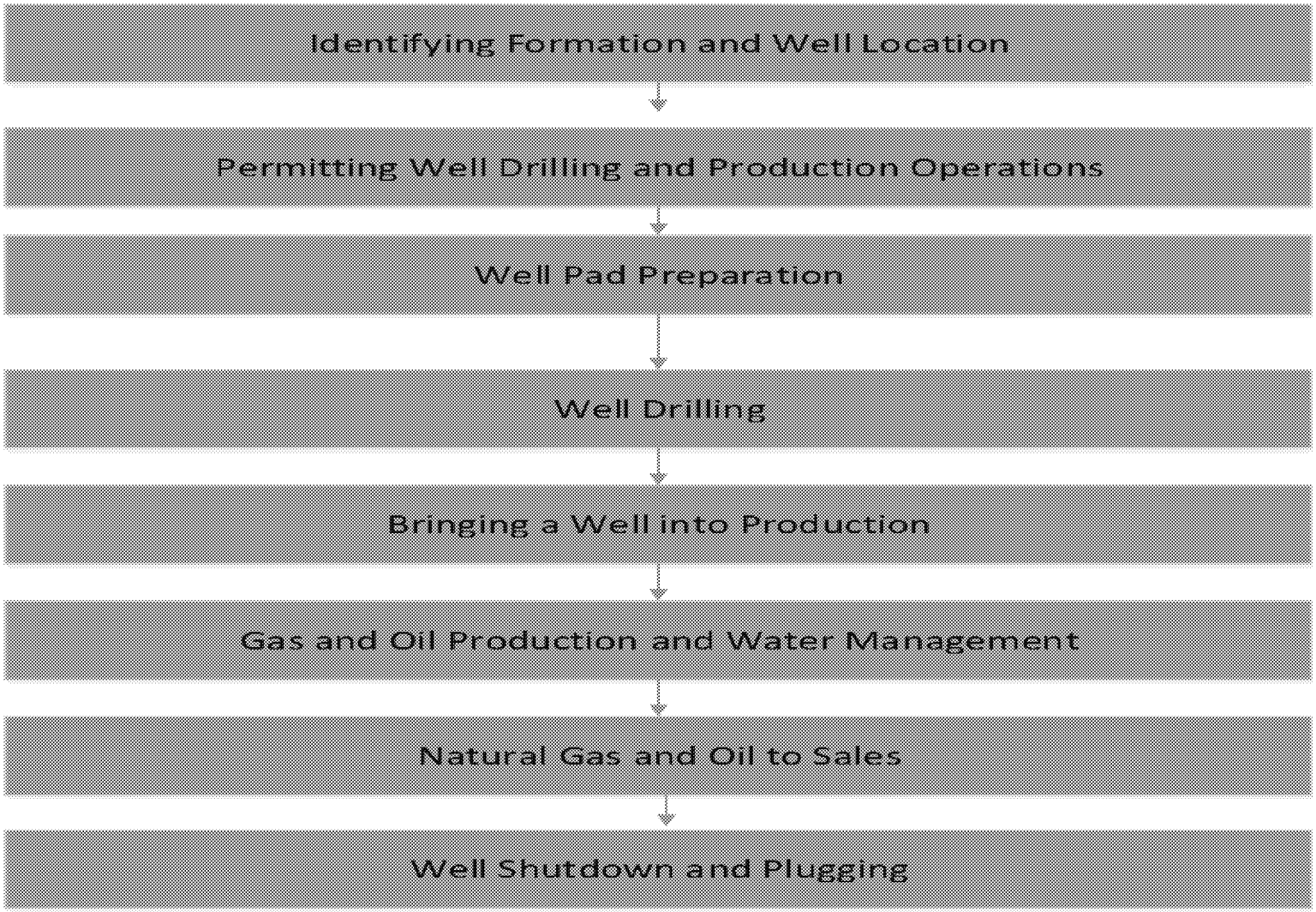
Life Cycle of an Oil and Gas Well



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Drivers to Reduce U.S. Methane Emissions

- **Public perceptions and pressure**
- **Conservation of resources**
- **Improved profitability due to oil and condensate capture**
- **Regulatory changes**
  - EPA GHG reporting rules (40 CFR Part 98, Subpart W)
  - New NSPS rules for oil and gas production facilities
  - Revisions to EPA NAAQS for SO_2 and NO_x
- **New State Regulations**
  - Revisions to state minor source permitting requirements
  - Reductions in thresholds allowing exemption from permitting in some states
  - State-specific GHG reporting regulations
  - State requirements for royalty payment calculations

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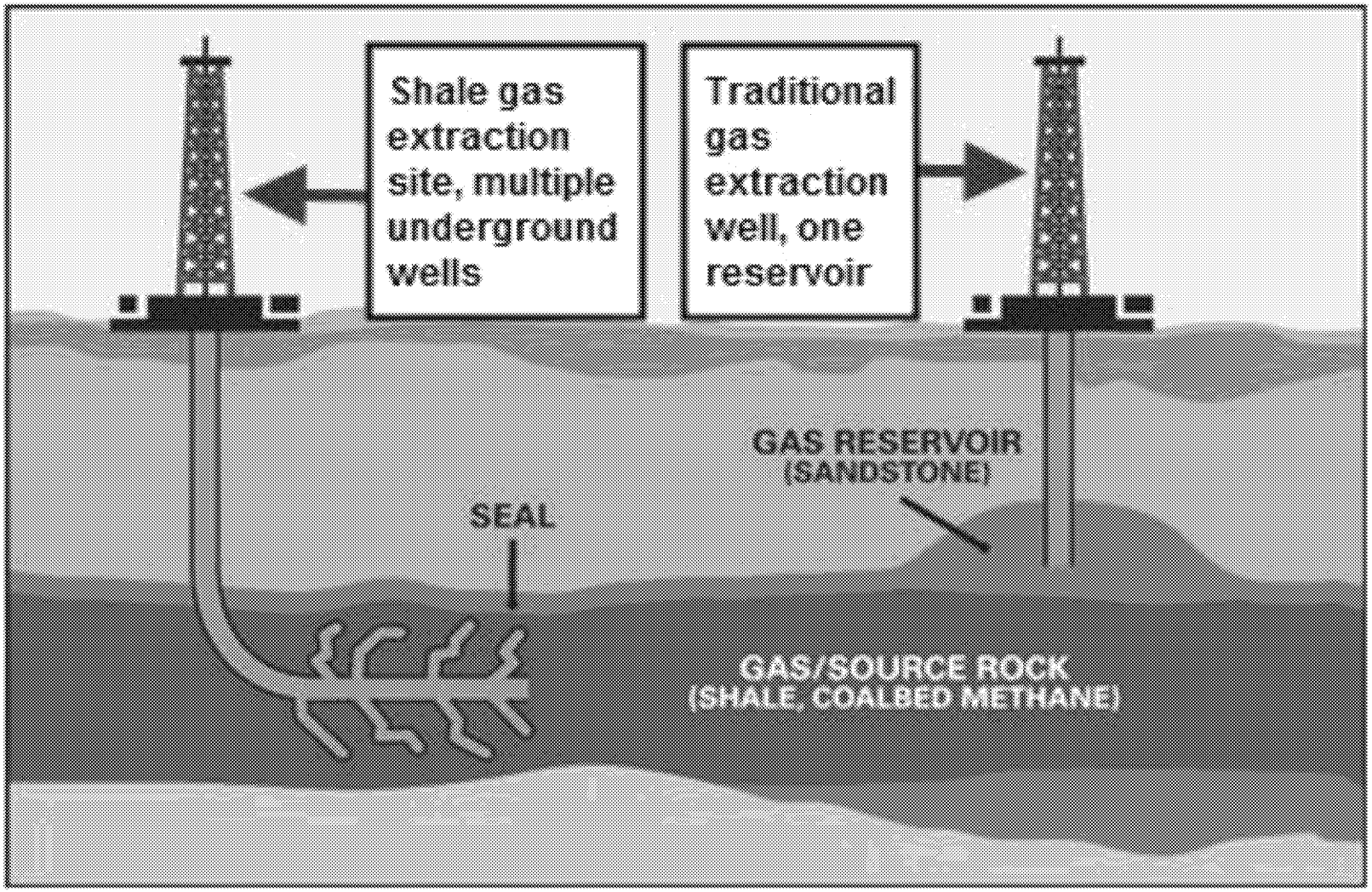
Gas Well Types



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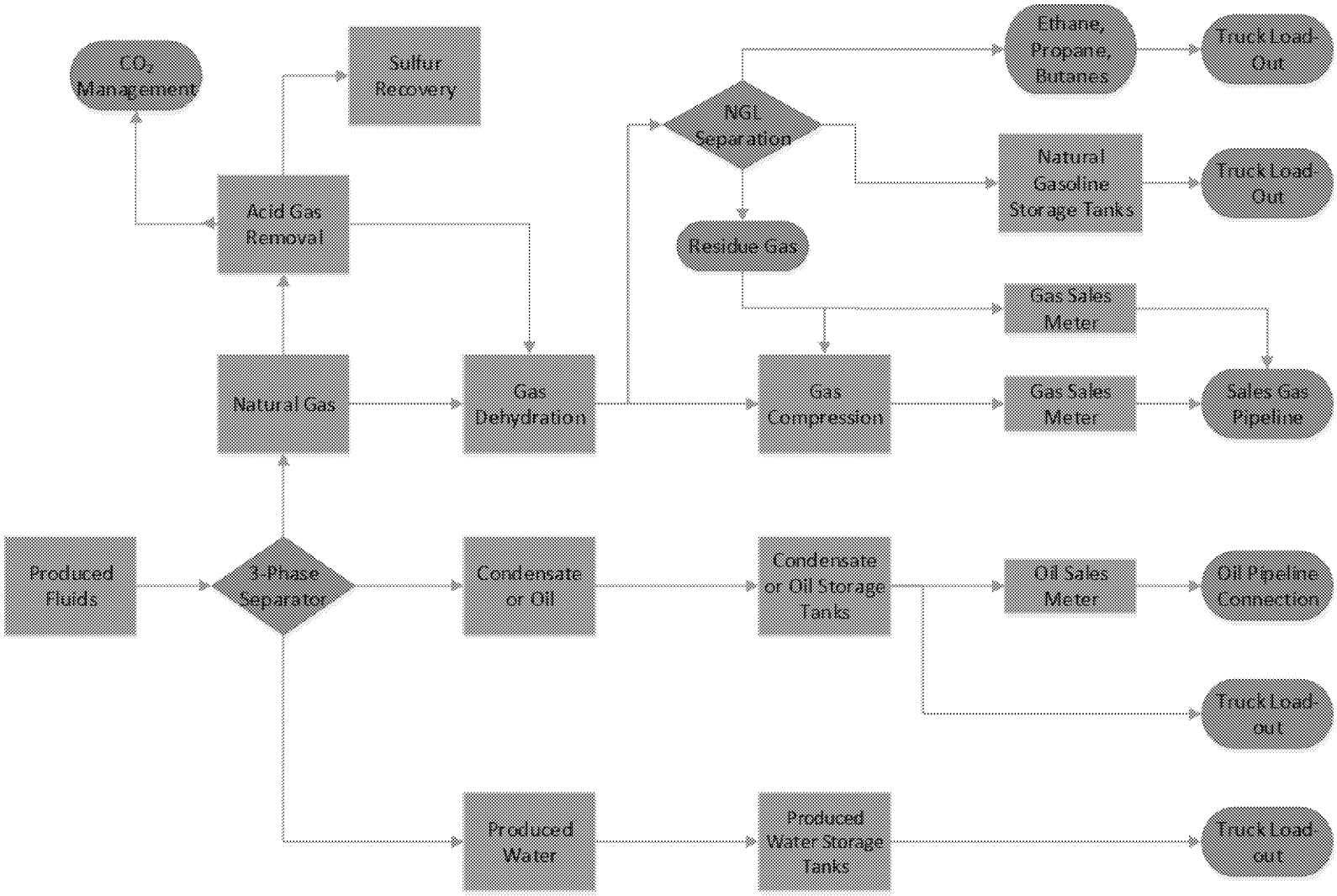
Oil and Gas Production Comprehensive Process Flow Diagram



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Key Sources of Methane Emissions

- **Well drilling**
- **Well completion**
- **Fracking flow back**
- **Natural gas venting during processing**
  - Separation
  - Dehydration
  - Acid gas treatment
- **Storage tank flash gas emissions**
- **Gas compressor seal leaks**
- **Pneumatic controller bleed vents**
- **Pneumatic pump activation**
- **Fugitive leaks from valves, piping and other components**

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GHG Emissions - Petroleum and Natural Gas Sector

GHG MRR Data for 2011

Number of facilities	1,880

Emissions	Million Mg
Total GHGs (CO_2e)	225

Emissions by GHG (CO_2e)	
Carbon dioxide (CO_2)	142
Methane (CH_4)	83
Nitrous oxide (N_2O)	1

Emissions by industry segment (CO_2e) (Million Mg)	
Onshore Petroleum & Natural Gas Production	94
Offshore Petroleum & Natural Gas Production	6
Natural Gas Processing	62
Natural Gas Transmission/Compression	24
Underground Natural Gas Storage	1
Natural Gas Local Distribution Companies	14
Liquefied Natural Gas Storage	<0.5
Liquefied Natural Gas Imp./Exp. Equipment	0.07
Other Petroleum and Natural Gas Systems	23

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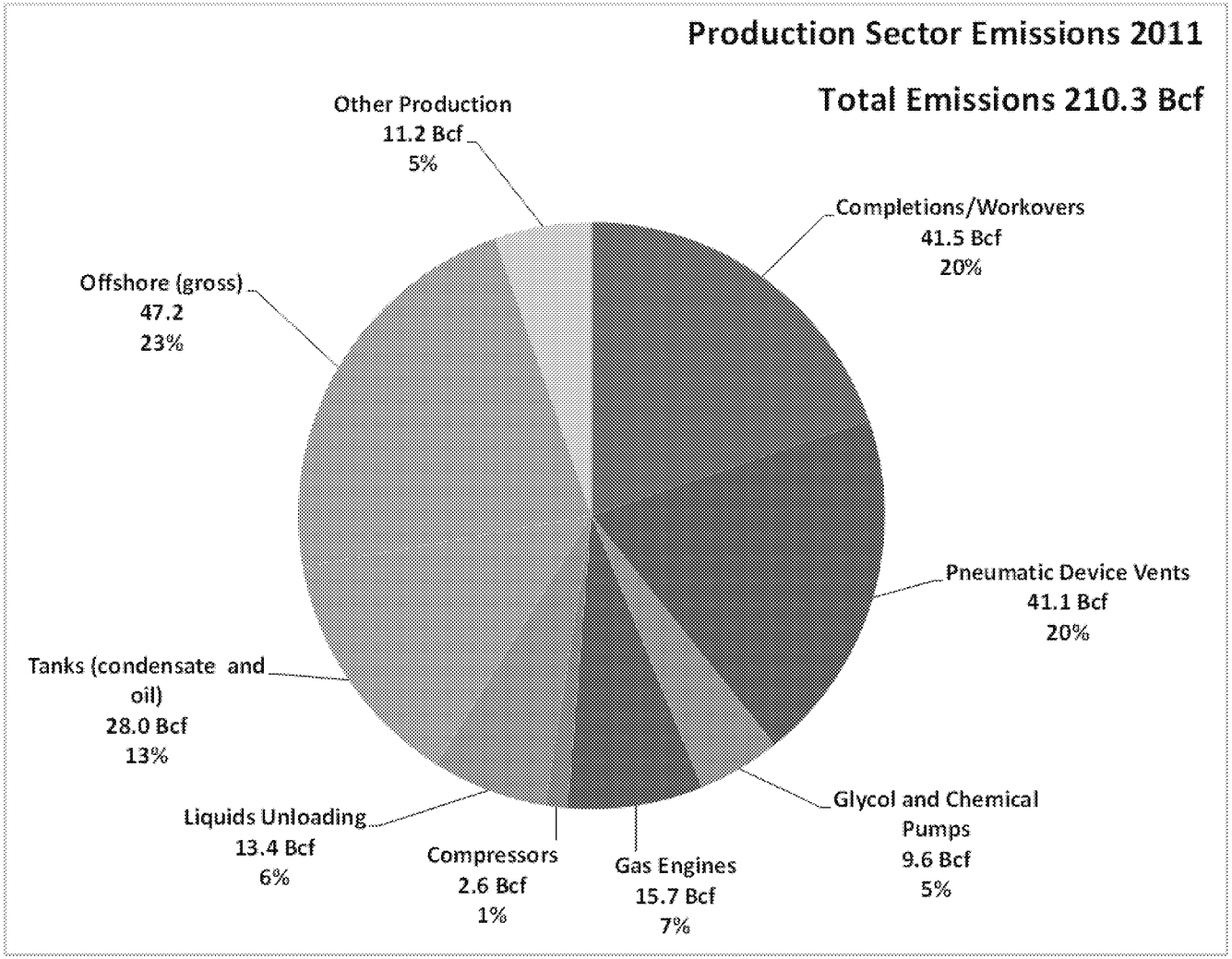
U.S. Petroleum and Natural Gas Production Methane Emissions



Source: U.S. EPA Breakdown of Sector Emissions, http://www.epa.gov/gasstar/basic-information/

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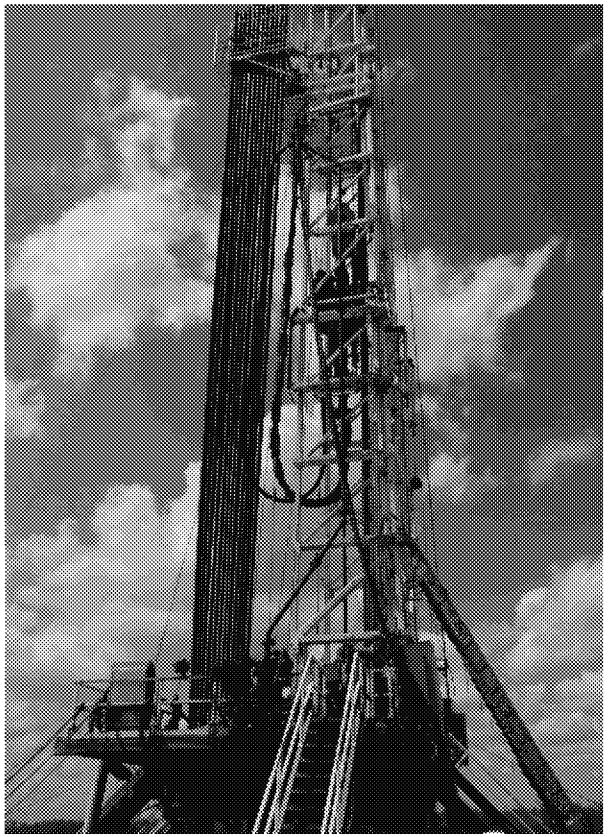
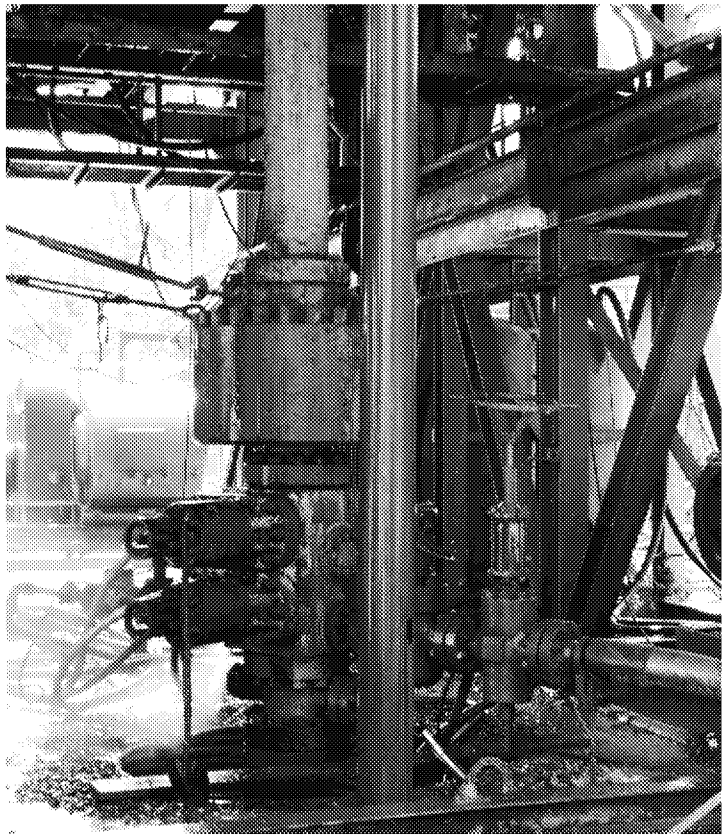
Well Drilling Activities

Drilling Rig (Typical)



Wellhead Blowout Preventer



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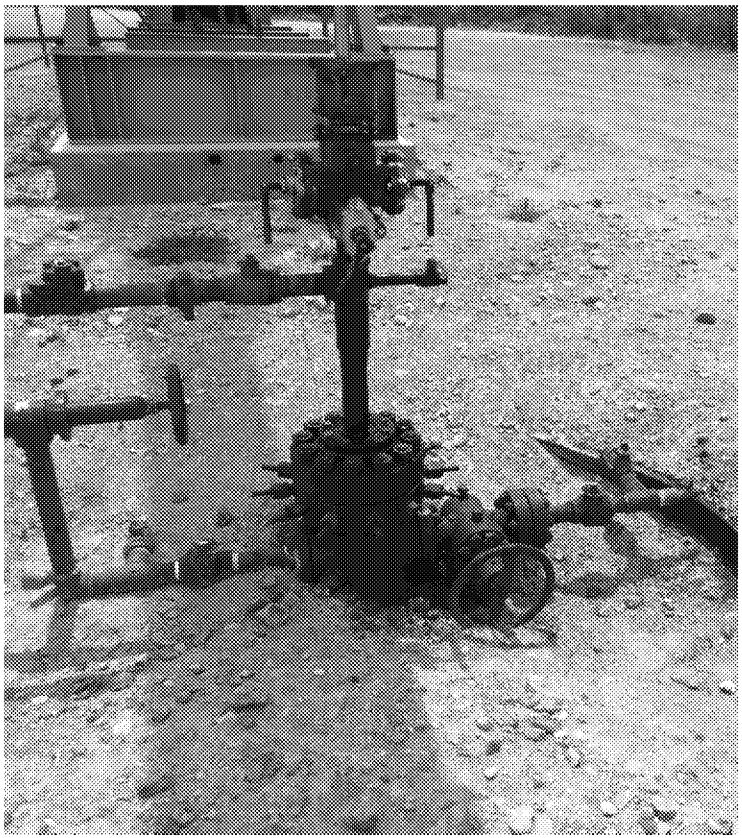
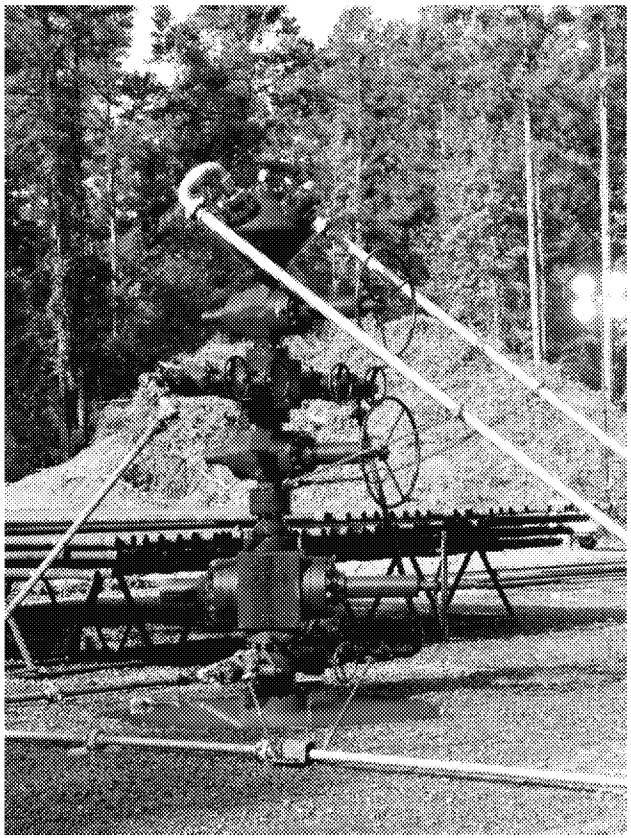
Typical Gas Well Surface Installations

Wellhead in Production Mode



Wellhead Rigged for Fracking



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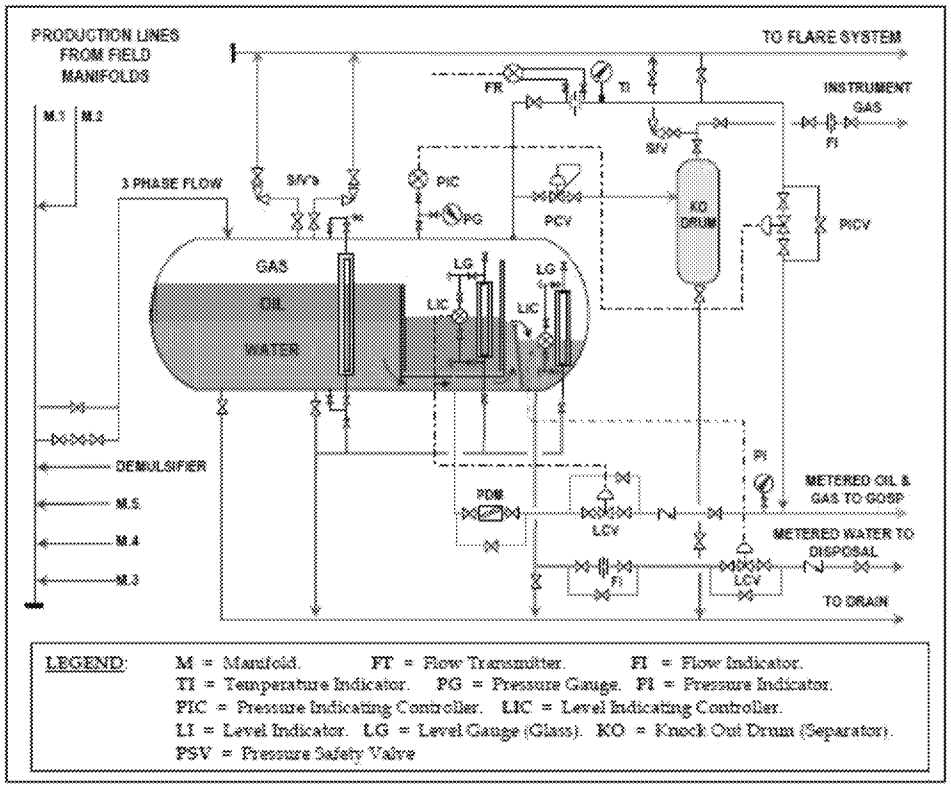
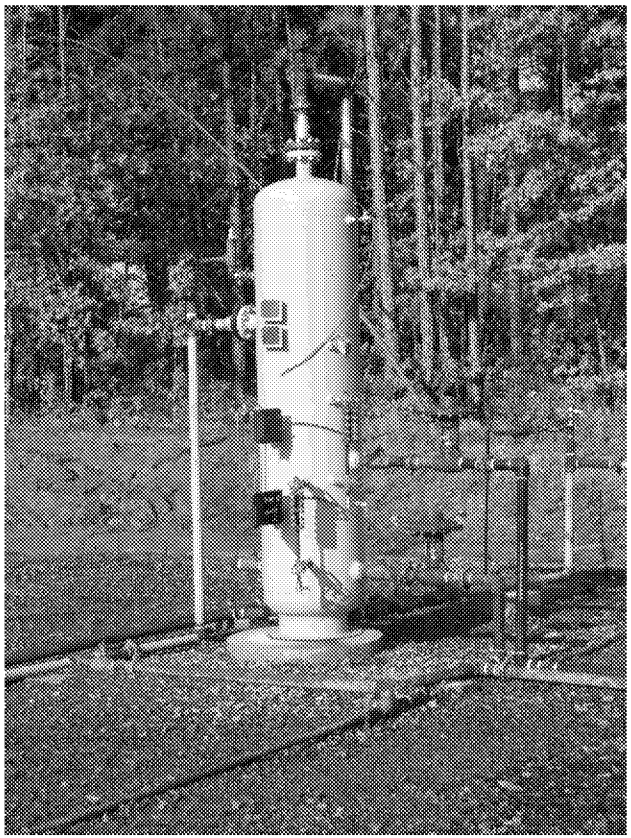
Gas-Liquids Separation

Horizontal Separator Flow Diagram



Vertical Separator Installation



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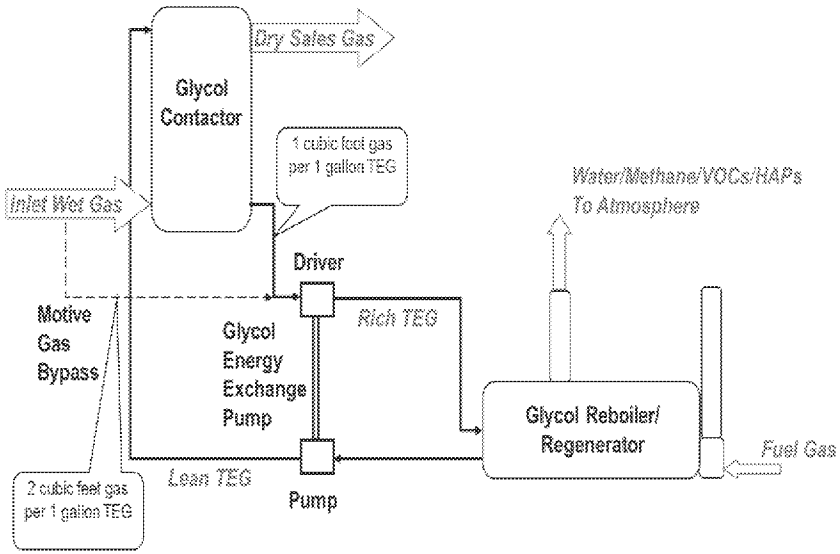
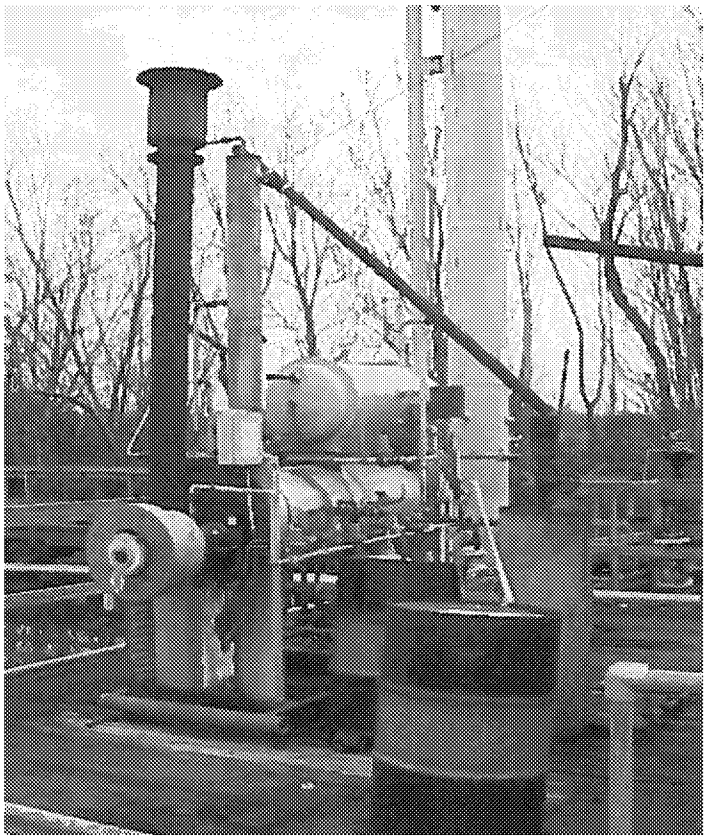
Glycol Dehydrator Unit for Moisture Removal

Process Flow Diagram



Glycol Dehydrator at Well Pad



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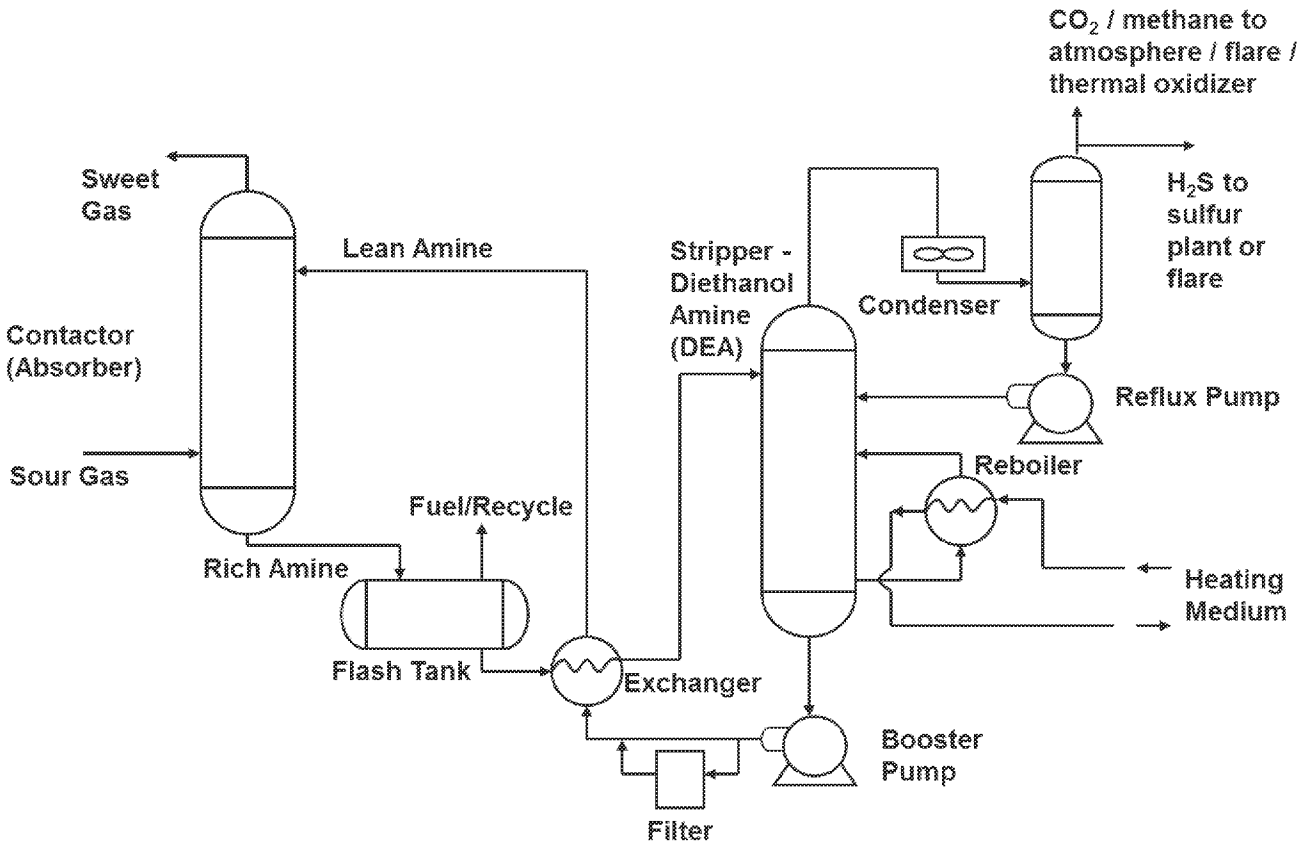
Acid Gas Treatment System



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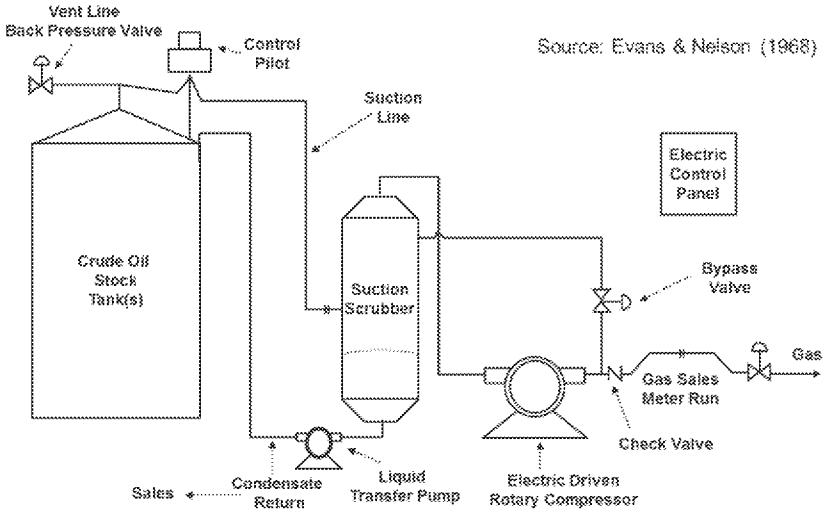
Stock Tank Configurations

Storage Tanks with Venting

Storage Tank with Vapor Recovery



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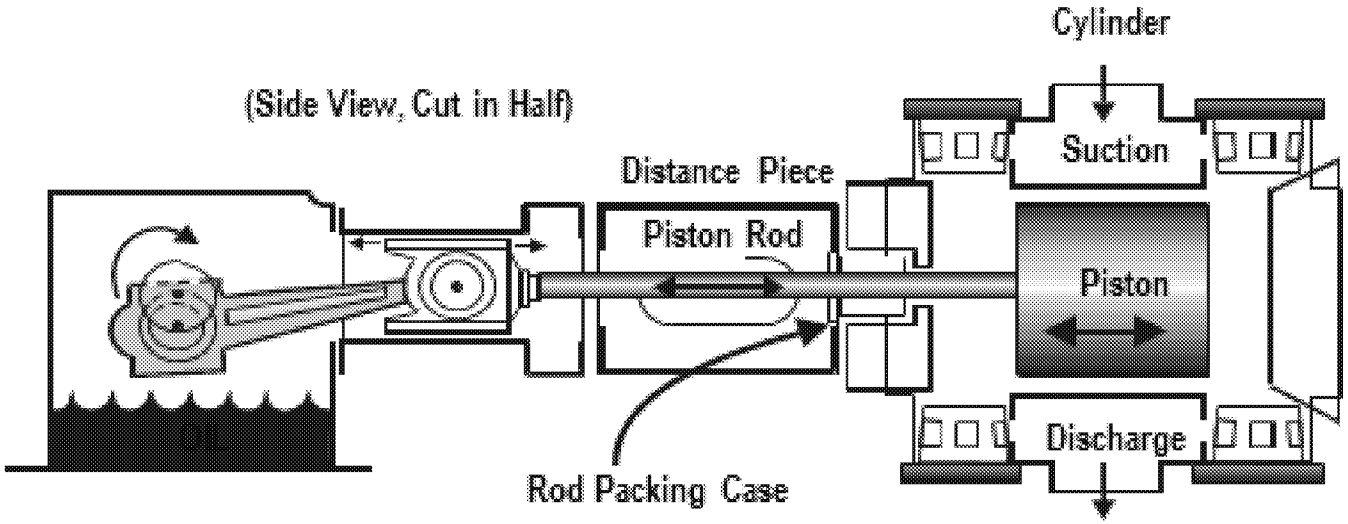
Typical Reciprocating Compressor Design



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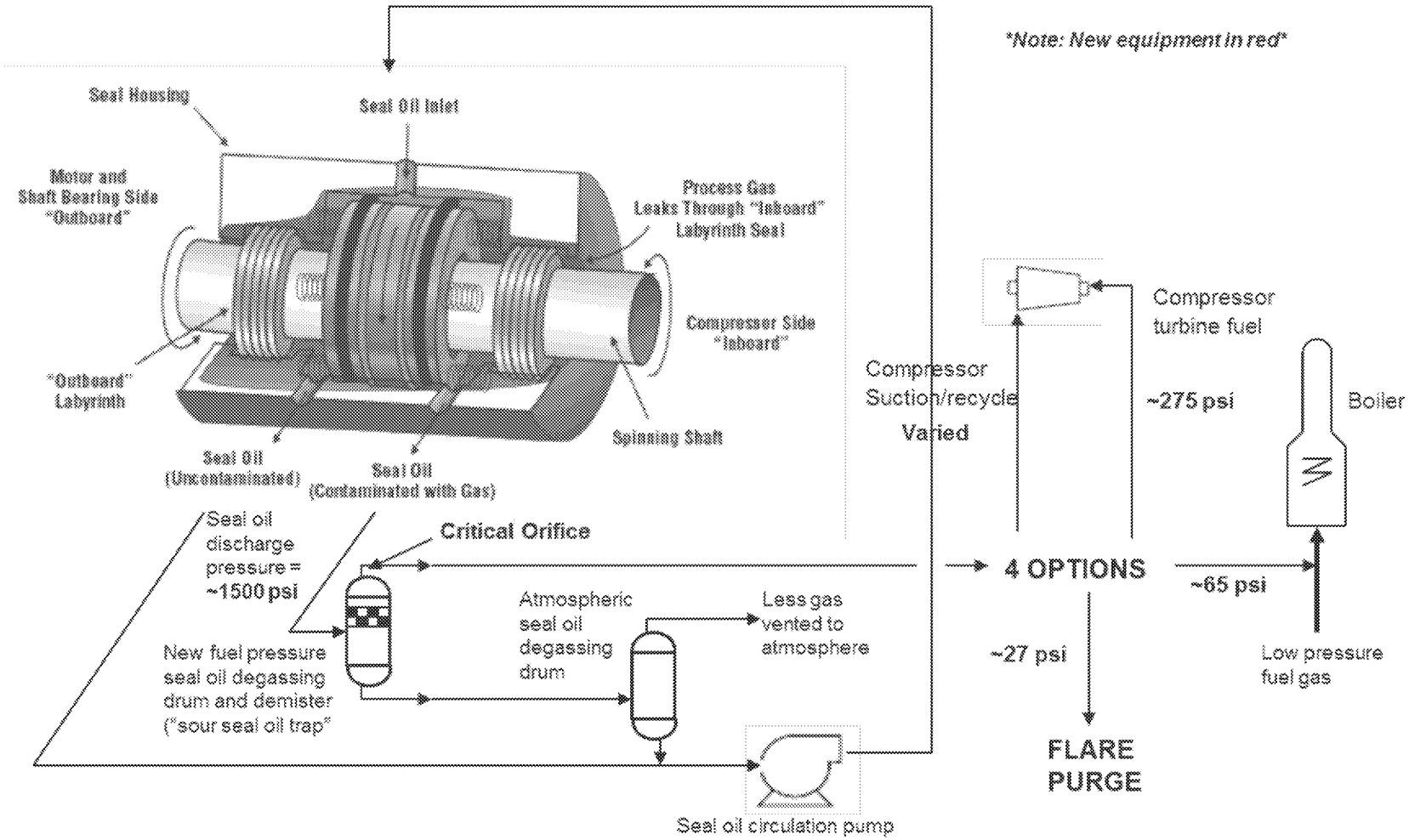
Centrifugal Compressor Wet Seal Design



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Typical Component Counts for Gas Production Emission Estimates

Equipment/Process	Connectors	Valves	Open-Ended Lines	Compressor Seals	Pressure Relief Valves
Wellheads	60	16	3		
Header Piping	105	26	4		
Heaters	147	22	4		2
Separators	160	30	5		3
Dehydrators	155	31	5		
Compressors	195	31	5	2	
Vapor Recovery Units	78	10	3		
Scrubbers	120	24	2		2
Flares	221	71	1		
Miscellaneous	177	32	5		2
TOTAL COMPONENTS	1418	293	37	2	9

Data Sources:

Canadian Association of Petroleum Producers (CAPP) *Calculating Greenhouse Gas Emissions*, Guide (April 2003), based on American Petroleum Institute (API), *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations* (December 1993)

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Reducing Methane Emissions during Liquids Unloading

- Liquids unloading operations at some gas wells are a normal process performed to reduce head pressure and increase gas production.
- Historically, liquids unloading has required opening up the well tubing to remove collected oil, condensate and/or water from the well bore
- This process is sometimes called "blowing the well" because the liquids and associated gas were allowed to vent to the atmosphere, releasing methane and other hydrocarbons
- Recent developments in equipment and controls have allowed an improved approach to removing liquids from gas and oil wells

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New Techniques and Operating Approaches for Liquids Unloading

- Plunger lifts are a proven means for removing well liquids
- Several types of plungers can be used, ranging from the traditional pump jacks to much smaller mechanical or gas operated units.
- Manual operation of plunger lifts is being replaced by automated systems that are customized to a specific well
- Well liquids removal can be continuous periodic to optimize production and energy use
- Well liquids removed are routed into the production stream where the components can be recovered
- Natural gas venting during liquids unloading is reduced or eliminated

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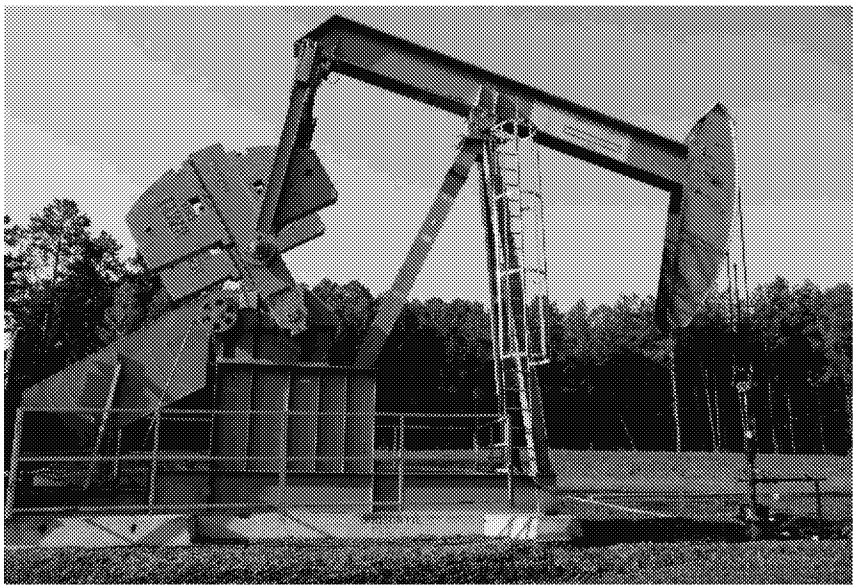
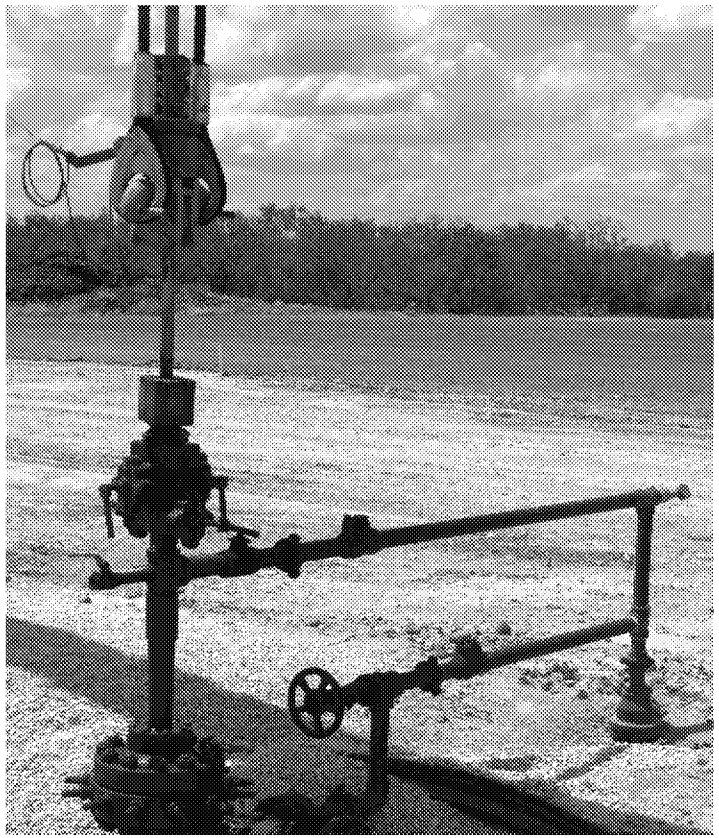
Liquids Unloading with Pump Jacks

Traditional Pump Jack System



Wellhead with Pump Jack Unit



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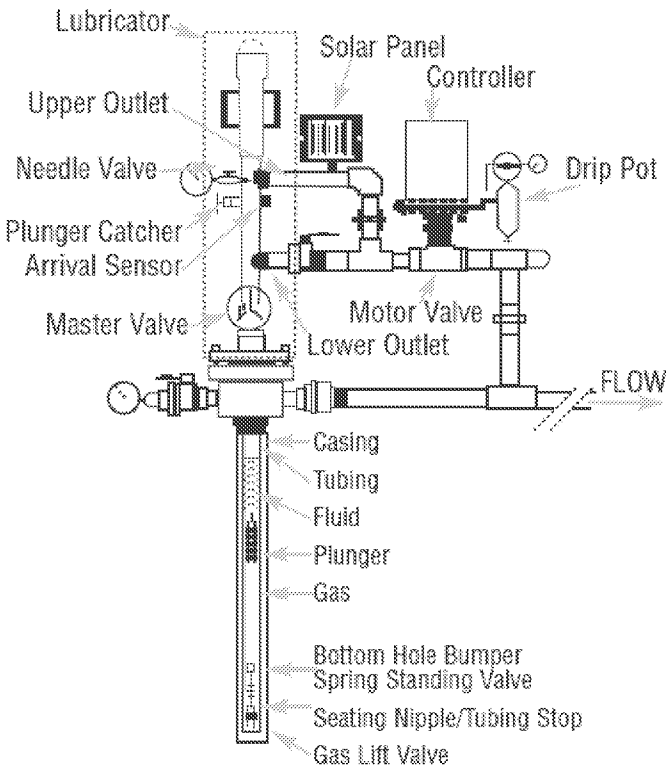
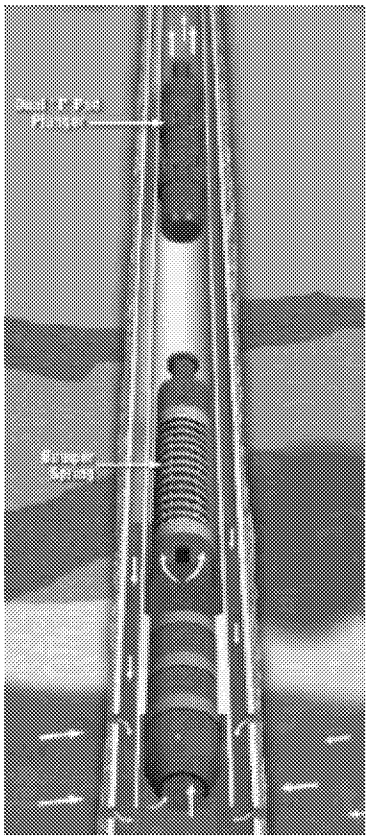
Modern Plunger Lift Systems

Process Flow Diagram



Plunger Lift System (Weatherford)



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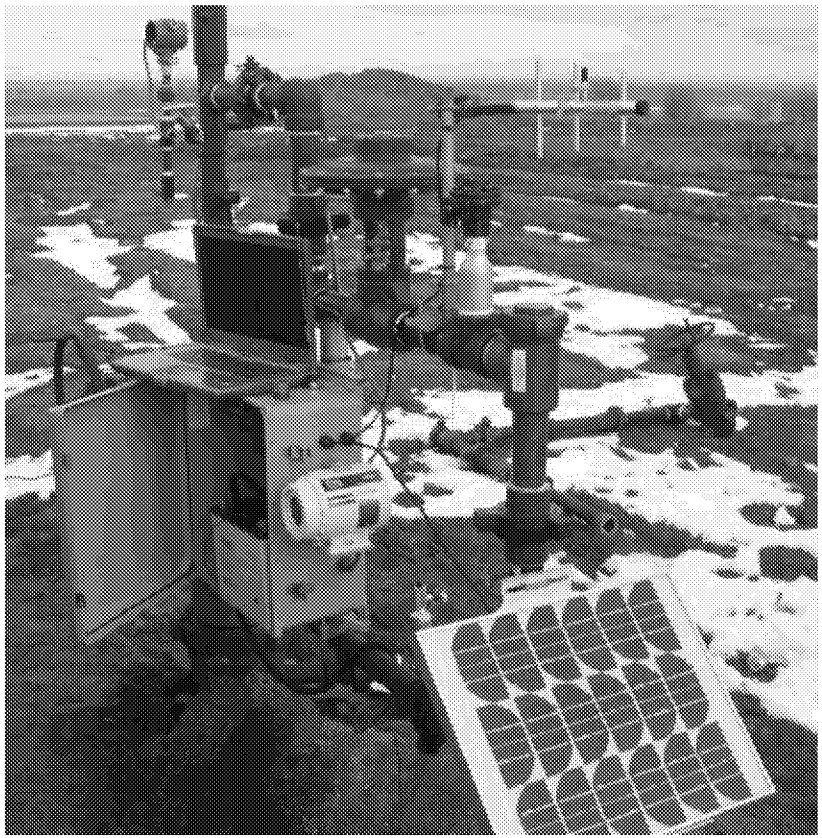
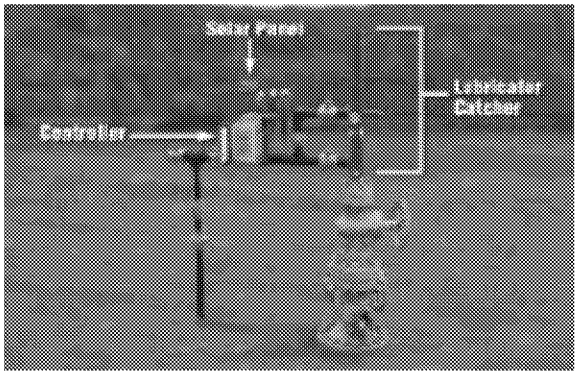
Plunger Lift Installations

Typical Solar-Powered Plunger Lift Installations





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Impacts of GHG Reporting Rules (40 CFR Part 98 Subpart W)

- **Require collection of data and calculation of emissions of methane and other GHGs for most production processes**
- **Establish procedures and data quality objectives for GHG reporting**
- **Specify methods for determining GHG emissions from units**
- **Address major sources of methane releases, including:**
  - Gas venting from well completions, fracking, and work-overs
  - Natural gas releases from pneumatic controller bleed vents and activation of pneumatic pumps and valves
  - Gas venting from uncontrolled separator, glycol dehydrator, and acid gas removal unit process vents
  - Flash gas venting from flash tanks or liquid storage (stock) tanks
  - Gas vented from equipment during maintenance and shutdowns
  - Fugitive emissions from valves, connectors, compressor seals, etc.

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NSPS Crude Oil and Natural Gas Production (40 CFR 60, Subpart OOOO)

- Establishes VOC control standards for oil and gas facilities constructed, modified, or reconstructed after August 23, 2011.
- Applies to each gas well; certain centrifugal and reciprocating gas compressors; high-bleed pneumatic controllers; storage vessels; and all other process units, except compressors at new oil and gas wells.
- Also include requirements that apply to certain existing gas wells that are re-fracked after October 15, 2012.
- Mandate use of low- or no-bleed pneumatic controllers
- Establish operating and maintenance practices for gas compressor seals and rod packings
- Require installation of VOC emission controls on storage tanks with uncontrolled emission rates of >6 tons/year on a schedule not yet published in the Federal Register
- Require, under the general duty clause, capture and beneficial use of produced hydrocarbons where technically feasible.

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Common Technologies Used to Reduce Methane Emissions

- Capture and control natural gas released from well completions, workovers, process vents, and storage tanks
- Replace high-bleed pneumatic controllers with low- or no-bleed devices, compressed air units, or electric actuators
- Utilize "Green Completion" methods to capture natural gas during well completions, fracking, workovers, and liquids unloading
- Replace plunger lift vented to the atmosphere with sealed systems
- Route captured natural gas to sales gas stream to minimize flaring, where practical
- Utilize advanced screening and measurement tools to improve leak detection and repair programs

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Emission Reduction Successes

- **Some states already requiring using "Green Completion" technology in advance of the NSPS OOOO 2015 deadline by:**
  - Routing well flow back to enclosed tanks with gas capture systems
  - Venting casing head gas to capture systems during completions and workovers
  - Reducing time between first production and sales gas pipeline connection
- **Replacement of high-bleed pneumatic controllers with lower emission alternatives has reduced methane emissions**
- **Increased use of central tank batteries for separation and gas processing improves natural gas capture because:**
  - Combined control systems are more economical
  - Centralized equipment improves maintenance and repair activities
  - Sales pipeline interconnection is simplified at a centralized facility

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Challenges Going Forward

- Current low value of natural gas negatively impacts cost recovery
- Lack of pipeline infrastructure or unwillingness to install increased capacity in some major gas producing areas limits the opportunity to route produced natural gas to sales markets
- Some resource recovery opportunities are limited by other constraints, e.g. lack of power grids to accept electric generation from waste gas
- Resistance to change may slow down voluntary implementation

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Summary

- The impacts of various drivers on reducing methane emissions from oil and gas production are already positive
- Regulatory and social mandate to produce pressures are driving oil and gas operators to modify traditional operating practices by reducing natural gas venting during oil and gas production
- Technology developments are allowing these operators to implement changes and capture and sell more natural gas
- Current oil and natural gas prices are driving production more toward liquids (oil and condensate) rather than gas
- As natural gas use and prices increase, the economics of capturing more gas for sales will become increasingly favorable

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QUESTIONS?

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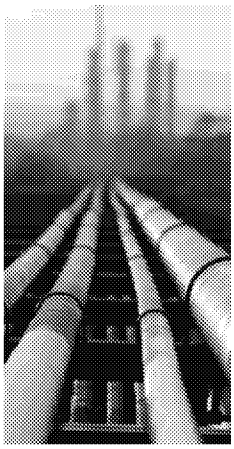
WHITE PAPER

Methane Emissions from the Oil and Gas Industry: "Making Sense of the Noise"



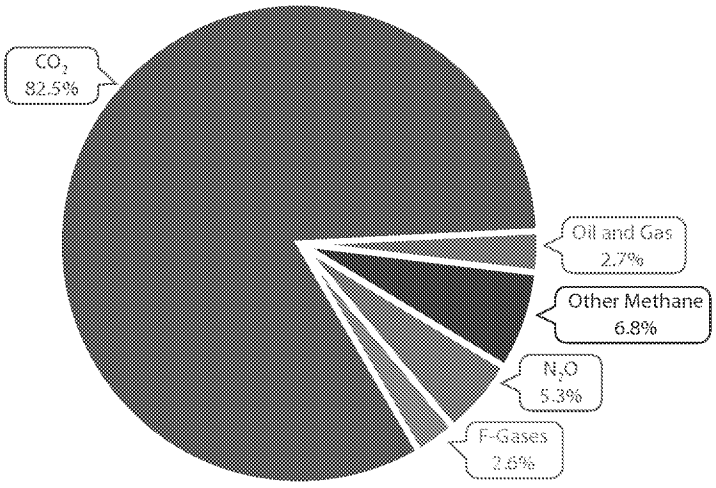
By Joel Bluestein, Hemant Mallya, Louis Yandoli, Michael Polchert, and Natalie Amarin

The Bottom Line

1. Methane is an important greenhouse gas (GHG) with a potentially low cost of reduction relative to CO_2.
2. New data are becoming available from various sources. However, they use different methodologies and represent diverse samples of the numerous oil and gas facilities.
3. This information is changing our understanding of sources, quantities, and patterns of methane emissions from the oil and gas sectors.
4. Our new understanding will affect estimates of emissions and future approach to mitigation and regulation of these sources. "Making sense of the noise" in judiciously applying all the new information is critical to successful mitigation and regulation.
5. ICF is making sense of this noise for clients on all sides of the debate and helping to reach consensus on what can be done.

Methane (CH_4) is a primary component of natural gas and the second largest source of U.S. greenhouse gas emissions. Figure 1 below shows the breakdown of GHGs, including methane, across the U.S. economy. Methane emissions make up approximately 9 percent of total U.S. GHG emissions. The agricultural sector is the largest source of methane emissions, followed by oil and gas systems. The focus has increased on reducing methane emissions from the oil and natural gas industry from fugitives (leaks), venting, and incomplete combustion because the value of methane as a natural gas can make recovery of reduced emissions a very cost-effective emission reduction measure.

Figure 1: Total U.S. GHG Emission 2013 in Million Metric Tonnes of CO_2e



Oil and Gas industry emits roughly 29 percent of total U.S. methane emissions

Source: 2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2015

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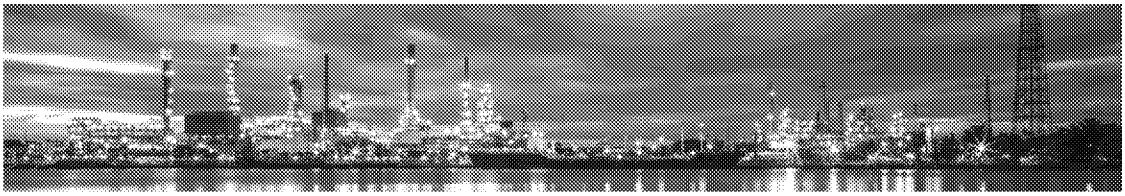


Describing Methane Emissions

All methane emissions are sometimes described as fugitives or leaks. However they are more accurately classified as:

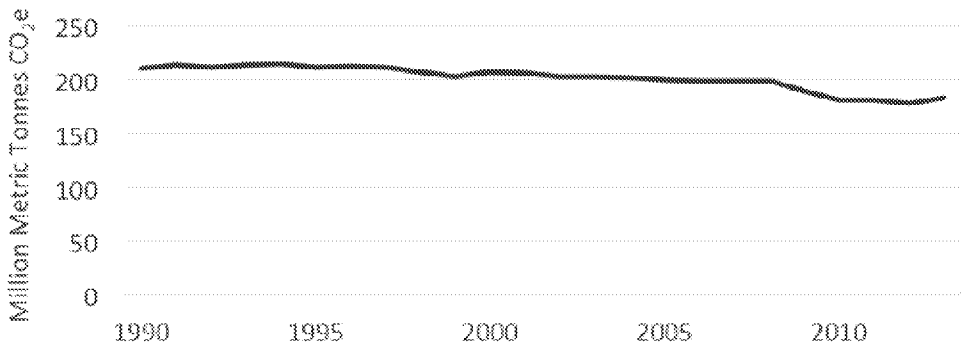
- Fugitive emissions—unintentional emissions due to randomly occurring leaks in flanges, valves, or other equipment because of operational wear and tear.
- Vented emissions—emissions resulting from equipment design or operating practices such as pneumatic devices or blowdowns.
- Incomplete combustion—uncombusted methane in the exhaust of equipment such as compressor engines and turbines.

Each one has different characteristics and must be addressed differently.

Recent Methane Emissions Trends

The figures below present recent methane emissions trends from the oil and gas industries. Figure 2 shows methane emissions from petroleum and natural gas systems based on the U.S. Environmental Protection Agency (EPA) Inventory 2015 Release for 2013 emissions.[1] Methane emissions have decreased from 1990 due to equipment turnover, voluntary industry actions, and in the past few years, regulations limiting methane emissions.

Figure 2: Methane Emissions from Petroleum and Natural Gas Systems



Source: 2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2015

Figure 3 displays gross natural gas gross withdrawal from oil and gas wells based on U.S. Energy Information Administration (EIA) data.[2] Gross withdrawals are defined by EIA as "full well-stream volumes, including all natural gas plant liquids and all nonhydrocarbon gases but excluding lease condensate."[3] Natural gas gross withdrawals have increased significantly over the past years as emissions have declined. Figure 4 combines the two trends to show the ratio of emissions to gross withdrawals and exhibits a declining trend as emissions decrease and withdrawals increase.

[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks, available at http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf.

[2] EIA Natural Gas Withdrawals and Production, available online at http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_nus_m.htm.

[3] Definition available at http://www.eia.gov/dnav/ng/TblDefs/ng_prod_sum_tbldef2.asp.

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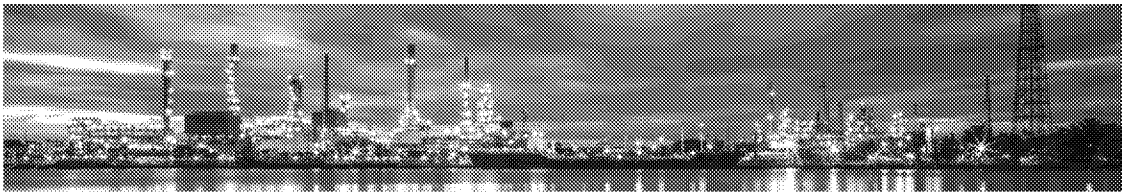
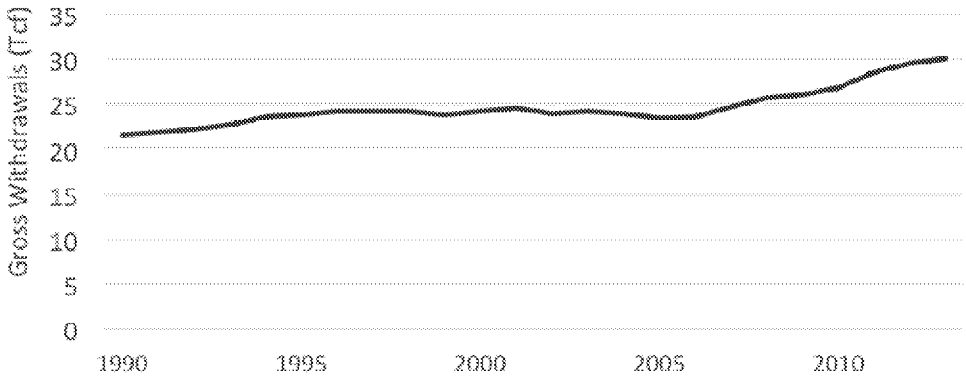
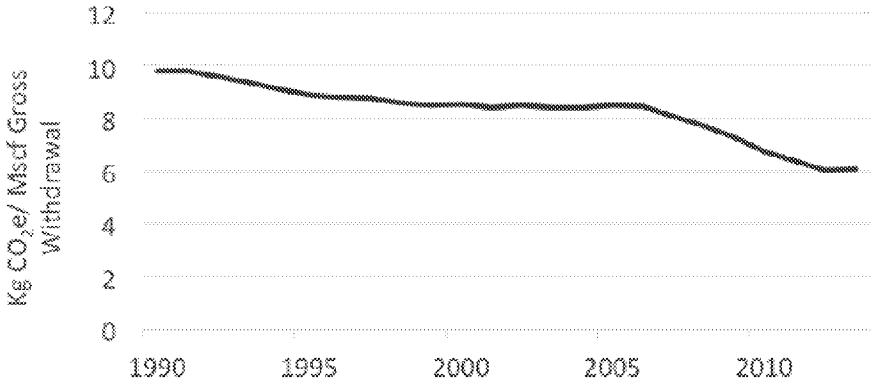


Figure 3: Gross Natural Gas Withdrawal from Oil and Gas Wells



Source: EIA Natural Gas Gross Withdrawals and Production

Figure 4: Methane Emissions per Mcf Produced



Source: 2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2015, and EIA Natural Gas Withdrawals and Production

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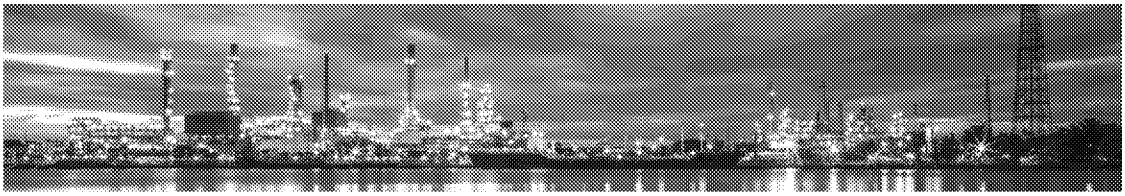


How are CH_4 emissions measured?

Volumetric basis: Expresses gaseous emissions in units of cubic feet (ft^3) or meters (m^3).

- 2013 U.S. inventory value—379 billion cubic feet (Bcf) of methane emitted from oil and gas operations.

Mass basis: Expresses the mass of methane emission emissions in units such as million metric tonnes (MMT) or gigagrams (Gg).

- 2013 U.S. inventory value—7.3 million metric tonnes of methane emitted from oil and gas operations.

CO_2e basis: Expresses the mass of GWP- weighted methane emission in units such as million metric tons of CO_2e (MMT)

- CO_2e has a GWP value of 1
- 2013 U.S. Inventory value, 182.5 CO_2e emitted from oil and gas operations

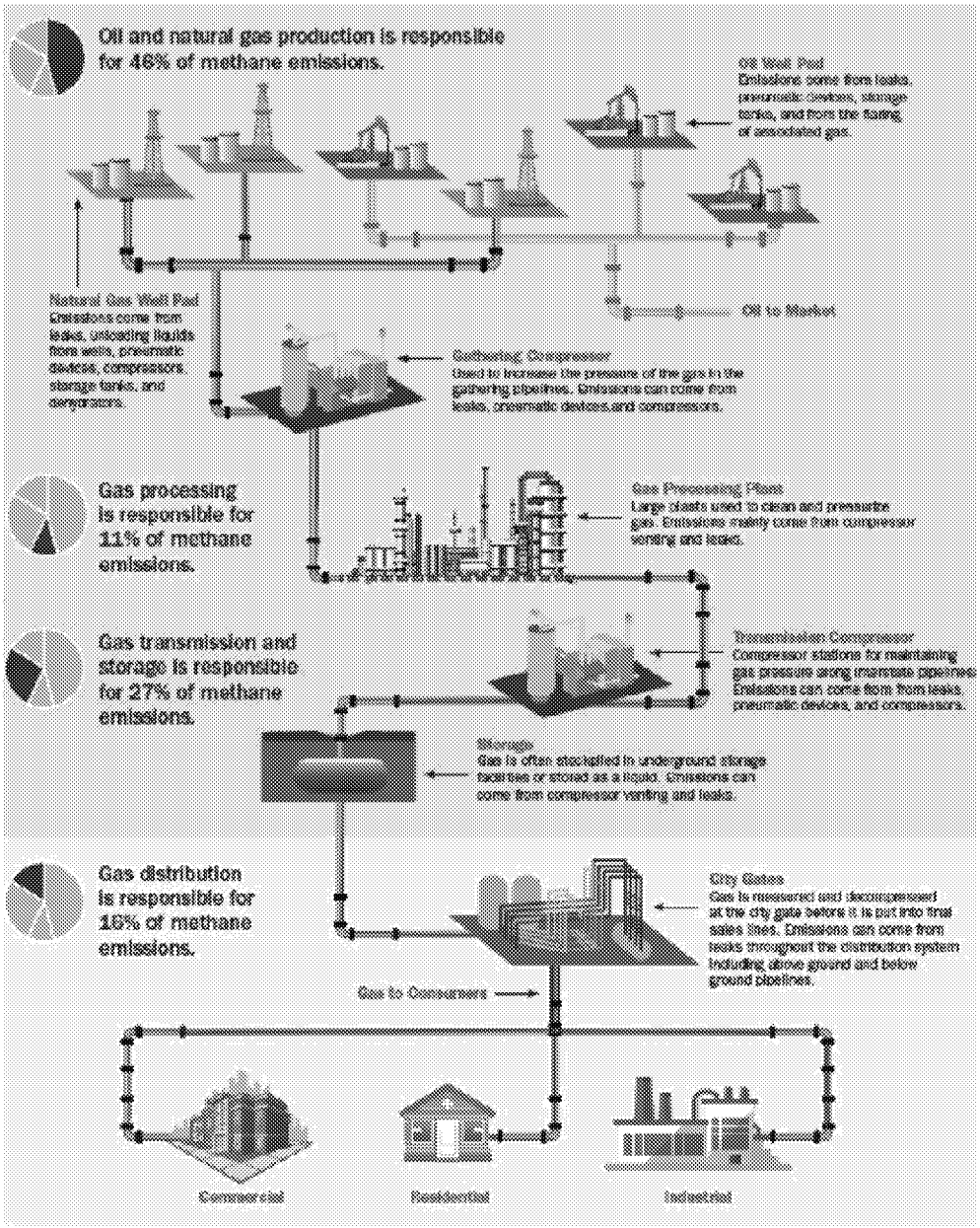
Percent of production: Expresses methane emissions as a percentage of natural gas produced annually in the U.S. – sometimes referred to as a "leakage rate".

- 2013 U.S. Inventory value, 1.3 percent emitted from oil and gas operations

A Look at the Oil and Natural Gas Supply Chain

Figure 5 below identifies the major components and major sources of emissions across the oil and gas supply chain.[4] Production is the largest source, with 46 percent of total emissions. Transmission is the second largest source.

Figure 5: Oil and Natural Gas Supply Chain[5]



[4] EPA, available at http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf.

[5] Clean Air Task Force, "Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry," 2014.

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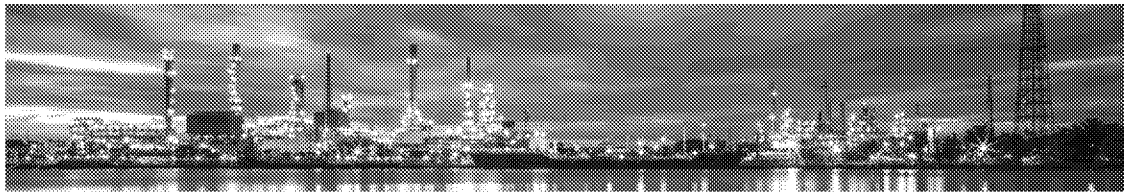

Global Warming Potential, Methane, and Climate Change

Certain gases are have a greater heat trapping effect in the earth's atmosphere than others. Global warming potential (GWP) characterizes different molecules and their climate change-inducing effects. Because different gases also have different lifetimes in the atmosphere, the GWP is calculated over 20 years and over 100 years. GWP values describe the warming effect of a gas relative to CO_2 (which has a GWP of 1). The International Panel on Climate Change (IPCC) is the authoritative source on GWP values for greenhouse gas and has published five assessment reports[6] to date on the topic of the scientific and technical aspects of climate change, the most recent AR-5 in 2014, preceded by the AR-4 in 2007. Table 1 shows the 100-year and 20-year GWP values for methane. For example, a GWP value of 25 for methane means 1 pound of methane emitted to the atmosphere is equivalent to 25 pounds of CO_2.

Table 1: GWP Values

	100-Year	20-Year
AR-4	25	72
AR-5	36	86

Source: IPCC Fourth and Fifth Assessment Reports

The selection of GWP values clearly has a significant effect on estimates of greenhouse gas emissions from oil and gas operations. National emissions estimates reported to the United Nations Framework Convention on Climate Change (UNFCCC), including the U.S. Inventory of Greenhouse Gas Emissions, use the AR-4, 100-year value of 25. The U.S. EPA Greenhouse Gas Reporting Rule (GHGRP—see below) uses the same value.

Methane Emissions Estimation and Reporting

There are two primary sources of U.S. national information on GHG emissions in general and methane in particular—the U.S. EPA Inventory of Greenhouse Gas Emissions and Sinks and GHGRP.

U.S. Inventory

U.S. GHG emissions from human activities (anthropogenic emissions) are compiled annually in the U.S. EPA Inventory of Greenhouse Gas Emissions and Sinks and submitted to the INFCCC according to IPCC guidelines.[7] The latest Inventory report was released in April 2015 and documents emissions from 1990–2013. (A two year lag exists in publishing emission estimates for the current year.) The U.S. inventory is the only economy-wide estimate of U.S. GHG emissions and also is the most complete compilation of methane emissions in the oil and gas segments across regions and segment levels (production, processing, transmission, and distribution). Many of the equipment and process emissions estimates in the Inventory are based on 1996 Gas Research Institute (GRI) measurement studies coordinated by EPA.[8] EPA is gradually updating these data sources as more recent information becomes available. As noted above, the most recent Inventory estimates methane emissions from the oil and gas industries to be 182.5 MMT CO_2e or about 1.3 percent of production.

[6] Available online at https://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml.

[7] Background on the UNFCC inventory submittal reporting requirements is available at http://unfccc.int/national_reports/items/1408.php.

[8] EPA and GRI. The primary measurement studies include Volumes 1–12 of from the title "Methane Emissions from the Natural Gas Industry," available at: http://www3.epa.gov/gasstar/tools/related.html.

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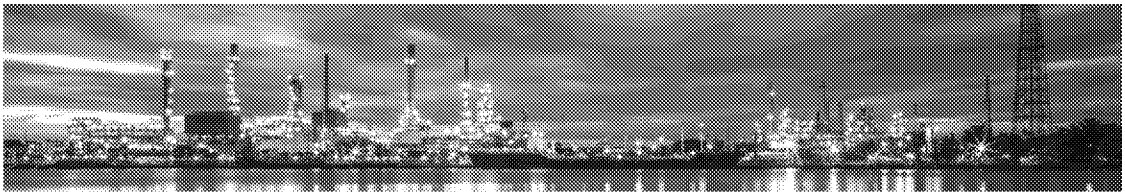

Greenhouse Gas Reporting Program Subpart W

GHGRP is mandated by the U.S. Congress and described in the U.S. Code of Federal Regulations Title 40, Part 98, established by EPA in 2009. GHGRP requires operators across various industrial sectors to report GHG emissions from specific emission sources. Reporting requirements for methane emission sources in the oil and gas sectors are described in Subpart W of the federal regulations. The reporting requirements apply to facilities that emit 25,000 metric tons or greater of GHG emissions (expressed in CO_2e) across one of the eight oil and gas segments: onshore production, offshore production, natural gas processing, natural gas transmission, natural gas storage, natural gas distribution, liquefied natural gas (LNG) import and export, and LNG storage. Specific emission sources within these segments include common field, plant equipment, and infrastructure such as storage tanks, distribution and transmission pipelines, pneumatic devices, dehydrators, combustion equipment and flares, and centrifugal and reciprocating compressors as well as production processes such as hydraulic fracturing and well completions, unrepaired equipment leaks, and gas well liquids unloading. Subpart W data are published by EPA yearly and are a resource for GHG emissions analysis. Emissions from natural gas gathering and boosting segment—the operations downstream of the wellhead involved in collecting produced natural gas and oil and sending it to other operations—are not subject to the original GHGRP but will be included under amendments proposed in 2014.

Methane Emission Studies

Beyond the federal emission data collection and reporting, a large number of recent methane emission studies reflect the growing interest in this topic. These studies can be classified into three main categories:

Bottom Up—These studies are based on on-site measurements of emissions from individual components. They are the most detailed but also the most time-consuming and expensive and must be extrapolated to the national level for comparison with high-level estimates. Several organizations, including the Gas Technology Institute,[9] have done recent bottom-up studies of different sectors. The Environmental Defense Fund (EDF) has organized a major effort of 16 studies[10] (top-down and bottom-up) of all of the segments of the oil and gas industry in coordination with companies and various academic institutions. The studies have provided a wealth of new direct measurement information. The major findings include:

- The importance of "super emitters"—the result that a small number of facilities or components account for a very larger share of emissions, possibly because of skewed distribution of leaking or malfunctioning equipment or a predominance of very large facilities.
- Revision of some old emission—At the same time, the studies show that the emission rates of the many of the emissions sources can be lower than indicated from older studies. This result may be due to a combination of equipment turnover, industry voluntary reduction programs, and recent regulation of methane emissions. For example, the Washington State University study[11] showed the emissions from gas distribution company systems are much lower than the 1990s GRI studies, largely due to equipment replacement.

[9] Gas Technology Institute, "Improving Methane Emissions Estimates for Natural Gas Distribution Companies, Phase II, PE Pipes," 2013, available at https://www.otd-co.org/reports/Documents/710c_OTD-14-0001-Improving-Methane-Emission-Estimates-NG-Distribution-Companies-PE-Pipes-FinalReport.pdf.

[10] EDF, "Methane Research: The 16 Study Series," available at https://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

[11] Lamb et al., "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Distribution Systems in the United States," 2015, available at http://pubs.acs.org/doi/ipdf/10.1021/es505116p.

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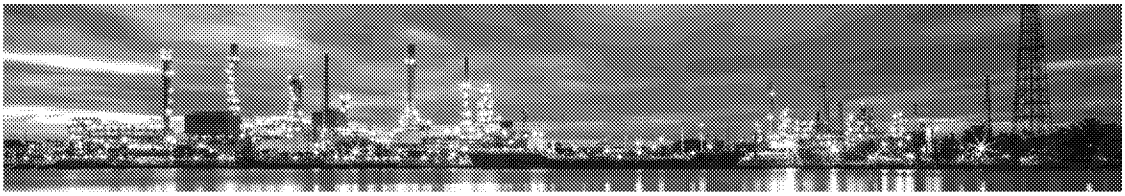

Much work still needs to be done to interpret the results and extrapolate them to the national level. Many follow-up questions to be addressed, but these studies have certainly improved the state of knowledge of equipment operations.

Top-Down—One approach of these studies is to measure the ambient concentration of methane in the atmosphere by taking samples from airplanes or tall towers. Another approach is to monitor the methane plume from facilities using tracer gas. These approaches tell us more about the actual level of methane emissions overall but require disaggregating the emissions contributions from different sources (e.g., oil and gas compared with agriculture and landfill) and may require complex modeling of airflows. Also, even if all the emissions are from an oil and gas facility, further allocation of emissions to individual sources within the facility is a challenging task. Several top-down studies indicate methane emission rates to be higher than indicated by the EPA inventory,[12,13] although the authors did not believe that they were representative of all oil and gas operations nationally. Another study found much lower estimated emission rates, particularly in the Marcellus shale region.[14] A metastudy of top-down studies[15] estimated that overall methane emissions could be 1.5 times higher than indicated by the EPA inventory. However, many of the studies predate recent voluntary and regulatory reduction efforts.

Finally, as part of the EDF study program, a study[16] attempted to correlate the top-down and bottom-up approaches by doing the studies at the same time in one area along with a concentrated effort to quantify the non-oil and gas sources. The study was successful in reconciling all of the sources and measurements, and noted that one source of variability was underrepresentation of the natural gas gathering segment in the EPA inventory.

Lifecycle Analysis (LCA)—Lifecycle analysis tabulates the emissions from the combustion and use of a fuel along with all of the upstream emissions from extraction, processing, delivery, and end use of the fuel, i.e., wellhead to burner tip. In the GHG realm, these emissions include both CO_2 and methane. LCA often is used to compare different fuels. Methane is an important component of the gas LCA because it is the primary component of gas and because of the multiplier aspect of its GWP. Although earlier gas LCAs were conducted, the work by Howarth and Ingraffea[17] in 2011 attracted a lot of attention because of its conclusion that shale gas had higher lifecycle emissions than coal. This result was largely due to the use of a very high factor for 20-year GWP and some assumptions about the emissions from shale gas operations. For example, the study assumed no mitigation of completion emissions although mitigation was required in a least one state and was reported by companies in voluntary programs. In any case, these emission reductions now are required by federal law (see below). Several studies refuted

[12] Petron et al., "New Look at Methane and Nonmethane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesberg Basin," 2014, available at http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/epdf.

[13] Karion et al., "Methane Emissions Estimate from Airborne Measurements over a Western United States Natural Gas Field," 2013, available at http://www.achd.net/shale/pubs/Karion_et-al_2013_Methane.pdf.

[14] Pesichl et al., "Quantifying Atmospheric Methane emissions from Haynesville, Fayettesville, and Northeastern Marcellus Shale Gas Production Regions," 2015, available at http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/epdf.

[15] Brandt, et al., "Methane Leaks from North America Natural Gas Systems," 2014, available at http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

[16] Harriss et al., "Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas," 2015, available at http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b02305.

[17] Howard et al., "Methane and the Greenhouse Gas Footprint of Natural Gas Shale Formations," 2011, available at: http://www.acsf.cornell.edu/Assets/ACSF/docs/attachments/Howarth-EtAl-2011.pdf.

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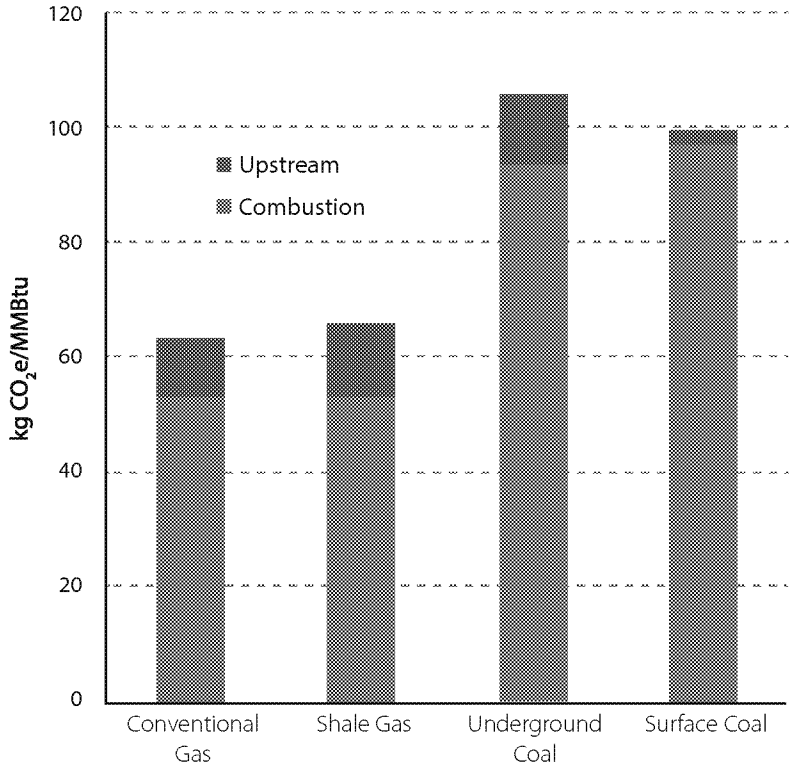
the Howarth conclusions,[18] and multiple studies addressed the issue independently. Several of the most detailed studies have been done by the National Energy Technology Laboratory (NETL). Figure 6 summarizes the results of one of the studies[19] that showed the burner tip lifecycle emissions of natural gas are about half those of coal, which is similar to the results of most of the studies.

Figure 6: Lifecycle Emissions of Natural Gas and Coal



Source: Role of Alternative Energy Sources: Natural Gas Technology Assessment DOE/NETL-2012/1539

Another important LCA study, performed by Alvarez et al.,[20] used a time-dependent weighting of the climate-forcing effect of methane rather than the average GWP. This study found that the use of gas would always have lower lifecycle emissions than coal. However, the average emission rate would need to be reduced to 1 percent of production for the lifecycle emissions to be lower than petroleum use in transportation over its full lifetime.

These studies are one way of bringing together the results of recent measurement studies. They highlight the importance of specifying the basis for comparison when evaluating emissions across different fuel types in addition to assumptions regarding methane leak rates across segments and fuels.

[18] Cathles et al., "Responses to Howarth et al.'s Reply," 2012, available at http://www.geo.cornell.edu/eas/PeoplePlaces/Faculty/cathles/Natural%20Gas/Response%20to%20Howarth's%20Reply%20Distributed%20Feb%2020,%202012.pdf.

[19] NETL, "Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production," 2011, available at http://www.netl.doe.gov/energy-analyses/pubs/NG-GHG-LCI.pdf.

[20] Alverez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," 2012. Available online at: http://www.pnas.org/content/109/17/6435.full.pdf

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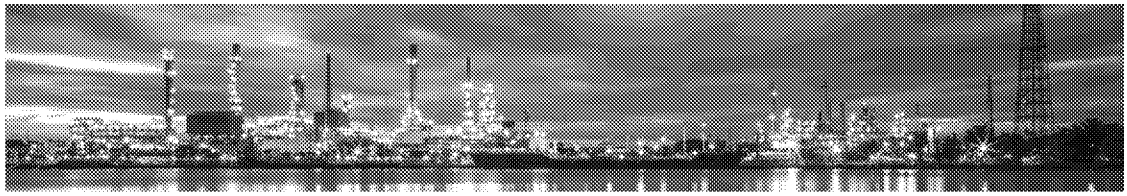

New Proposed CH_4 Regulations: NSPS OOOOa

These regulations propose control of the following emission sources in the industry:

Compressors (Centrifugal and Reciprocating)

- 95 percent proposed reduction of methane and volatile organic compound (VOC) emissions from wet seal compressors.
- Regular rod packing replacement or emissions capture.

Pneumatic Controllers

- Emission controls (either 6 scfh emission reduction or zero bleed rate for controllers at natural gas processing plants).

Pneumatic Pumps

- Emission controls (including 95 percent emission reduction for gas-driven chemical and methanol pumps and diaphragm pumps).

Hydraulically Fractured Oil Well Completions

- Increased use of reduced emission completions.

Production Well and Compressor Station Fugitive Emissions

- Includes regulator optical gas imaging survey requirements and repair of equipment component leaks.

Federal and State Methane Regulations

States, including Colorado and Wyoming, had started to regulate gas industry operations that emit methane in the 2000s. Federal regulation of the oil and gas industry had historically been focused on control of gaseous volatile organic compound (VOC) and hazardous air pollutants (HAPs) emissions from specified equipment and process sources. An update to the New Source Performance Standards (NSPS OOOO) for VOCs from new and modified sources and the National Emission Standards for Hazardous Air Pollutants (NESHAP) in 2012 for oil and gas operations had the added benefit of limiting methane emissions from some significant sources. Methane emissions were directly regulated from oil and gas operations under the Colorado Regulation Number 7 in 2014, focusing primarily on fugitive emissions from upstream sources. In 2015, EPA proposed updates to federal NSPS OOOO (NSPS OOOOa) requirements, which regulate methane from some additional new and modified sources directly. The new sources include hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, and pneumatic pumps. Table 2 presents a review of prominent federal and state emissions regulations for the oil and gas industries.

Table 2: Federal and State Regulation of Emissions from the Oil and Gas Industry

Regulation	Type	Sources Covered and Highlights
NSPS OOOO (2012)	Federal Regulation	• Regulates VOCs from oil and gas operations but results in methane emissions as a co-benefit. • Applied to new and modified sources only.
NESHAP Subpart HHHH (2012)	Federal Regulation	• Regulates HAPs but results in methane emission reductions as a co-benefit. • Covers sources such as equipment leaks, storage vessels, and glycol dehydrators.
Colorado Regulation #7 (2014)	State Regulation	• Directly regulates methane. • Focuses on fugitive emissions from upstream sources.
Proposed NSPS OOOOa (2015)	Proposed Federal Regulation	• Applies to new and modified sources only. • Specifically covers methane emissions. • Addresses additional sources such as hydraulically fractured oil well completions and re-completions, fugitive emissions, compressor seals, and pneumatic pumps.

Federal Voluntary Emission Reduction Programs

Several very successful voluntary methane reduction partnerships between EPA and industry have been created. The EPA Natural Gas STAR program was initiated in 1993 to foster government and industry collaboration in knowledge sharing and implementation of cost-effective emission reduction strategies and measures. EPA states that 109 domestic oil and gas companies have eliminated 1.15 trillion cubic feet of methane emissions by adopting roughly 150 technologies and mitigation practices.[21] The Natural Gas STAR International program was launched internationally under the Global Methane Initiative (GMI) in 2006. Since GMI's inception, EPA estimates that international companies have succeeded in mitigating 77.8 Bcf of methane emissions.[22]

[21] EPA, Natural Gas STAR Program, available at http://www.epa.gov/gasstar/.

[22] EPA, Natural Gas Star International, available at http://www3.epa.gov/gasstar/international/index.html.

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More recent government-industry partnerships include the Natural Gas STAR Methane Challenge program (anticipated to launch at the end of 2015 and designed to incorporate industry emission reduction goals into Subpart W GHG reporting requirements) and the Climate and Clean Air Coalition (CCAC) Oil and Gas Methane Partnership (OGMP). Launched in 2014, the CCAC OGMP began as a collaboration between seven founding oil and gas companies—BG Group, ENI, PEMEX, Southwestern Energy, Statoil, PTT, and Total—and national governmental and nongovernmental organizations, including EPA, Environmental Defense Fund (EDF), and the World Bank's Global Gas Flaring Reduction Program. CCAC partners are engaged to evaluate cost-effective emission control technology for nine core emissions sources and share findings and successes.

Industry Voluntary Emission Reduction Programs

Industry-led emission reduction partnerships also aim to reduce methane emissions from the lifecycle of oil and gas production operations. Two illustrative voluntary partnerships include ONE Future and the Center for Sustainable Shale Development (CSSD). The goal of ONE Future members is to reduce industry-wide methane emissions to 1 percent of production through flexible voluntary actions. The members include Southwestern Energy Company, AGL Resources, Hess Corporation, Apache Corporation, Kinder Morgan, Inc., BHP Billiton, and National Grid. ONE Future has been recognized by EPA as alternative approach for participation in the proposed Methane Challenge program.

CSSD includes industry partners and nongovernmental environmental organizations that aim to incorporate industry best practices in developing shale resources in the Appalachian Basin. CSSD has established performance standards addressing water, waste, and conventional pollutants as well as methane. The methane standards focus on flaring limitations, use of green completions, and storage tank emission controls.[23] CSSD partners established the performance standards to achieve greater methane emission mitigation results than those obtainable through adherence to state and federal government requirements and standards.

Conclusions

Methane is an important greenhouse gas due to its magnified effect on warming. It also has a potentially low cost of reduction relative to CO_2 due to the value of gas that can be recovered through mitigation efforts. A large amount of new information on methane emissions is becoming available and changing our understanding of the sources, quantities, and patterns of methane emissions from the oil and gas sectors. The new data have been collected by using different estimation and measurement techniques and over across diverse geographic locations. This new understanding will affect our estimates of emissions and the future approach to mitigation and regulation of these sources. "Making sense of the noise" is essential for success. ICF is providing help to clients on all sides of the debate and facilitating consensus on what can and should be done.

[23] Center for Sustainable Shale Development, "Performance Standards," available at https://www.sustainableshale.org/performance-standards/.

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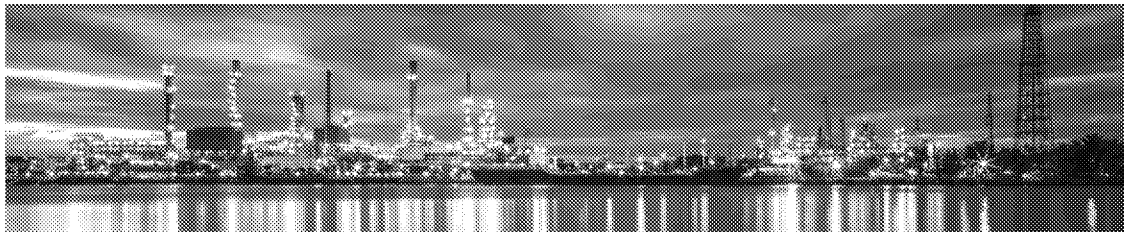

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Oil and Gas Industry: Practices, Equipment, Emissions, Regulations and Controls

March 2017

Oil and Natural Gas Supply Chain

Production, Processing, Storage, Transmission, and Distribution

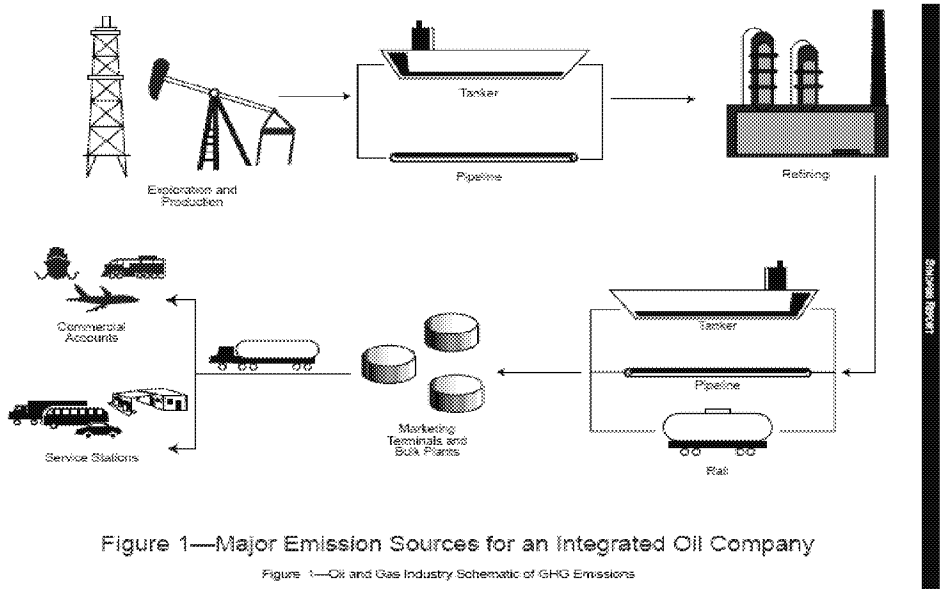

Figure 1—Major Emission Sources for an Integrated Oil Company

Figure 1—Oil and Gas Industry Schematic of GHG Emissions

2

Source: American Petroleum Institute: Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations. Page 4.

Oil and Natural Gas Supply Chain:
Operations and Emissions

Per API, the emission sources of all oil and gas operations (including refineries) include:

- Combustion devices - stationary (burners, flares) and mobile (trucks, ships) sources
- Point sources - stacks, vents, and ducts
- Non-point sources - fugitive emissions, wastewater treatment facilities, and other sources involved in waste handling
- Non-routine activities - non-scheduled maintenance or emergency operations
- Indirect emissions - emissions associated with company operations but physically occurring elsewhere, such as purchased electricity.

Emissions Associated with Fracked Wells

Fracked Wells: Exploration and Completion

- Equipment, practices, emissions, regulations, and controls

Source: ICF, 2015

Fracked Wells: Pre-production

- Equipment, practices, emissions, regulations, and controls

Fracked Wells: Production

- Equipment, practices, emissions, regulations, and controls

Fracked Wells: Processing and Storage

- Equipment, practices, emissions, regulations, and controls

Transportation

- Equipment, practices, emissions, regulations, and controls

Fracked Wells: Equipment/Activity related Ranked VOC Emissions (percent)

Fracked Wells: Ranked Normalized VOC Emissions (percent)

Data Gaps

WORLD RESOURCES INSTITUTE

WORKING PAPER

REDUCING METHANE EMISSIONS FROM NATURAL GAS DEVELOPMENT: STRATEGIES FOR STATE-LEVEL POLICYMAKERS

MICHAEL OBEITER AND CHRIS WEBER

EXECUTIVE SUMMARY

The techniques of hydraulic fracturing and horizontal drilling, in combination, have opened up vast new areas for natural gas production, and low-cost natural gas has altered the energy landscape in the United States. Prior to the last decade, some states located in shale gas basins had little experience with significant oil and gas extraction, but are now among the leaders in the production of natural gas.[1] The rush to develop this new resource has resulted in numerous environmental challenges, including water and air quality concerns, leading many to question the natural gas industry's environmental record and potentially jeopardizing its social license to operate. Preventable emissions of methane—a potent greenhouse gas[2]—are among the easiest of those challenges to address, and policies that address those emissions have the co-benefit of reducing local air pollution.

Methane emissions are not a new phenomenon, but the pace of natural gas development in the United States has brought much deserved attention to the issue. According to the U.S. Energy Information Administration, marketed production of natural gas increased by 44 percent between 2005 and 2014, and is projected to increase another 30 percent or so by 2040.[3] If the United States is to develop its natural gas resource to such an extent, it is imperative to address the air quality, water quality, and climate concerns that such development will bring. Acknowledging the broader environmental impacts of natural gas development, this paper focuses on practical solutions that have been demonstrated to reduce methane emissions significantly without creating undue economic hardship for industry or consumers.

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Working Papers contain preliminary research, analysis, findings, and recommendations. They are circulated to stimulate timely discussion and critical feedback and to influence ongoing debate on emerging issues. Most working papers are eventually published in another form and their content may be revised.

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Reducing leakage over the natural gas lifecycle to one percent or less of total production is an achievable and cost-effective benchmark in the near term, and ensures that natural gas is less climate-intensive than diesel fuel and gasoline, when used in transportation, and coal when used for electricity generation.[4] Partly for this reason, Southwestern and other companies have founded the ONE Future Coalition, setting a one percent leakage rate target for their entire value chains.[5]

Some recent studies suggest that methane emissions from U.S. natural gas systems are more—and perhaps much more—than one percent of natural gas production at this time, though others have confirmed the estimates in the Environmental Protection Agency's (EPA) Greenhouse Gas Inventory.[6] State regulators and legislators have a number of tools at their disposal to help companies overcome market barriers to greater implementation of emissions-control technologies and achieve this benchmark;[7] which of these policy tools makes the most sense can vary by emissions source, the severity of the problem, or local conditions that might pose legal or political challenges.

Several federal agencies are taking some steps to reduce methane emissions. For example, Bureau of Land Management is undertaking a rulemaking to limit the venting or flaring of natural gas on federal lands.[8] And EPA has announced that it will propose standards for some new natural gas infrastructure in 2015, and will finalize those standards in 2016.[9] Because EPA is not addressing the significant methane emissions from existing infrastructure, states have the opportunity to achieve both deeper emissions reductions and public health benefits. Moreover, differing geologies and other local considerations make state-level policymakers uniquely well positioned to identify the solutions that work best within their jurisdictions. Also, in recent years, policymakers at the state level have led the way in addressing some of the largest sources of methane and other air pollutants from natural gas systems.[10] Yet there is still much more that states and the federal government can do to reduce the environmental and climate footprint of natural gas systems.

State oil and gas commissions issue permits for drilling and gathering lines, and can set performance standards for natural gas extraction. State air and environmental agencies implement air quality rules, which are of particular importance to the production and processing sectors. State regulatory agencies enforce safety regulations and other rules governing interstate transmission pipelines. Public utility commissions oversee the natural gas distribution system, and weigh the costs and benefits of emissions-reduction measures to ensure that ratepayers are not unduly burdened with higher costs.

Through case studies, key recommendations for new rules, and descriptions of best practices, this working paper can help state officials to determine how best to structure future state-level policies—including measures for complying with forthcoming national emissions standards under the Clean Air Act—to reduce methane emissions from natural gas development. The measures laid out in Table ES-1 are among the best practices for reducing methane emissions throughout the natural gas value chain, and can inform the development of new policies to limit such emissions. All of the measures listed should be paired with a rigorous monitoring and verification program, to ensure that all potential reductions are realized.

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Table ES-1 | Key Recommendations for Methane Emissions Reduction Policies[11]

PRODUCTION, PROCESSING, AND TRANSMISSION		
SOURCE	**POLICY RECOMMENDATIONS AND BEST PRACTICES**	**PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[12]**
Reciprocating Compressors		19
Seals	Replace rod packing systems every three years at existing compressors along transmission lines and on gathering and boosting lines, and require annual maintenance to ensure good working order. When appropriate measurement technology is available, states should ensure that emissions from reciprocal compressors are reduced to 11.5 standard cubic feet (scf) per hour—the average emissions from newly installed rod packing.[13] As an alternative compliance option, states could require the capture of leaking natural gas and its re-routing back into the compressor engine, to be combusted to power the compressor.	
Static Components	States should also require regular leak detection and repair (LDAR)[14] for compressors at processing plants and along gathering lines.	
Pneumatic Devices	States can go beyond the requirements set forth in Colorado's new rules targeting pneumatics by requiring the following: ■ retrofits of continuously or intermittently emitting high-bleed pneumatics (that is, devices that vent significant quantities of natural gas as part of their normal operations) with no-bleed or low-bleed equivalents as soon as practical, to bring their emissions down below a low-bleed threshold of six scf per hour,[15] ■ regular LDAR to identify excessively emitting equipment, which can be repaired or replaced, and ■ all new and replacement controllers upstream of the processing plant to be powered by compressed air or electricity instead of compressed gas when access to the electric grid is available, and with low-bleed pneumatics when it is not.	12
Liquids Unloading	Where external power sources or high-pressure gas are available, an artificial lift—powered either by electricity or gas—should be used during every unloading event. When external power sources are not available, plunger lifts should be used during every unloading event. Because plunger lifts have been demonstrated to reduce methane emissions by 95 percent or more when used properly, well operators should be required to use plunger lifts and avoid venting wherever feasible.[16] States should ensure that well operators are trained in best practices in order to maximize emissions reductions from liquids unloading events.	4

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Table ES-1 | Key Recommendations for Methane Emissions Reduction Policies[11] (continued)

PRODUCTION, PROCESSING, AND TRANSMISSION		
SOURCE	**POLICY RECOMMENDATIONS AND BEST PRACTICES**	**PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[12]**
Equipment Leaks	States should require two-stage LDAR for all production facilities, processing plants, compressor stations, and large, above-ground distribution facilities. Mobile air monitoring—whereby air-sampling technology is mounted to a vehicle to check for high concentrations of methane—should be performed at least quarterly. States should phase in this requirement to allow companies to purchase or lease the appropriate emissions monitoring equipment. A complete leak detection survey using optical gas imaging (OGI) or portable analyzers should be performed semi-annually, to ensure that all leaks are detected. When mobile monitoring detects methane or Volatile Organic Compound (VOC) levels higher than background levels, follow-up OGI or portable analyzer screenings should be performed to locate the source of the leak. Once discovered, leaks should be repaired within five calendar days if possible. If the leak cannot be repaired within five days, either because needed parts are unavailable or because facility operations would need to be shut down, then repairs must be made within 15 calendar days, or as soon as practical.[17] Companies should report the results of their mobile monitoring surveys to the state, which can make those reports public, and state officials should ensure that all leaks have been repaired by performing spot checks of production, processing, and transmission facilities within their borders.	19[18]
Centrifugal Compressors		9
Seals	Performance standard for all existing centrifugal compressors of six scf per minute, which represents the average emissions factor for dry seal systems, and an 87 percent reduction below typical emissions levels from wet seal systems.[19] This standard can be met either by replacing wet seals with dry seals, or capturing gas leaked from wet seals (to be re-routed back to processing and later sold), the latter of which can reduce vented methane emissions from de-gassing seal oil by up to 99 percent.[20]	
Static Components	In conjunction with measures to reduce emissions from wet seal centrifugal compressors, all compressors should be subject to a rigorous LDAR program. As described above, and in greater detail below, states should implement a two-stage program, to increase the effectiveness of performing LDAR without burdening industry with unnecessarily high costs.	
Engine Exhaust	When an electric power supply is available from the grid, or on-site distributed generation is feasible, electric motor starters should be used for all engine start-ups. When this is not the case, gas starters should either be replaced with air or nitrogen, or operators should capture the gas used in the starters. As with centrifugal compressors, engines should be included in all LDAR surveys.	11
Pipeline Venting	For planned maintenance, pipeline operators must use portable compressors—either alone or in conjunction with in-line compressors located at the compressor station—to reduce pipeline pressure to 90 percent below normal operating levels. For emergency repairs, when there is not enough time to secure a portable compressor, maintenance teams should use in-line compressors to reduce pipeline pressure to 50 percent below normal operating levels (if doing so does not present a safety hazard).	3

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Table ES-1 | Key Recommendations for Methane Emissions Reduction Policies[11] (continued)

DISTRIBUTION	
POLICY OPTION	**DESCRIPTION**
Pipeline Replacement Programs	State regulators should allow for accelerated pipeline replacement programs, which would likely require higher prices for gas customers. Regulators should ensure that lower-income households are not adversely affected by any price increase.
Leak Reclassification	State legislators or regulators should work with natural gas utilities to modify the existing system of leak classification, which does not assign a high priority to repairing large leaks that do not pose a threat to people or property. Such leaks should be categorized as Tier 2, and should be repaired within a reasonable amount of time (for example, three months or less).
Leak Inspection	Utilities should be required to use vehicle-mounted emissions detection equipment to survey their entire network of distribution pipelines at least twice per year.
Meter Replacement	To reduce the quantity of gas that is "lost and unaccounted for" between the city gate and end-users, residential and commercial meters should be tested for accuracy at least once every seven years.[21] If flow accuracy is found to have fallen below 98 percent, the meter should be replaced.

INTRODUCTION

As the shale gas boom opens up new areas for natural gas development, states that have long been unaccustomed to significant oil and natural gas development are confronting the need to regulate those industries for the first time.[22] Numerous challenges—from wastewater disposal to smog and other air quality concerns—must be overcome to protect the public interest and to enable natural gas companies to retain their social license to operate. Among those challenges, the issue of methane emissions from natural gas production, processing, and transmission is perhaps the easiest to address (see Table 2 for emissions sources by supply chain segment). Well-designed policies can reduce unnecessary leaks and vents of methane, minimizing the waste of a valuable resource and saving the industry money while simultaneously reducing other forms of air pollution as a co-benefit.

Methane, the primary component of natural gas, is a potent greenhouse gas, with 36 times the heat-trapping power of carbon dioxide over 100 years.[23] How much methane is leaking into the atmosphere from natural gas infrastructure is not yet known, but even the lowest estimates indicate that methane emissions are a significant problem, and one that will only grow larger with increased natural gas production unless further emissions-control policies or incentives are introduced (See Box 1 for a discussion of forthcoming standards from the Environmental Protection Agency (EPA) that address emissions from new sources).[24] Leakage rate estimates vary widely.[25] EPA's 2015 Greenhouse Gas Inventory suggests around 1.2 percent of natural gas is lost between the well and the end user. However, a number of studies propose that EPA might be significantly understating the magnitude of the problem, and suggest leakage rates at least 50 percent higher than EPA estimates, with considerable regional variations.[26]

Many natural gas leaks emit both methane and other pollutants. Before natural gas is processed to strip out many of the impurities, it is composed of roughly 70-90 percent methane, and 10–30 percent ethane, propane, and other volatile organic compounds (VOCs) and hazardous air pollutants (HAPs).[27] VOCs are precursors to smog formation, and HAPs include carcinogenic chemicals such as benzene. Because of the public health and air quality consequences of VOC and HAP emissions, most policies that address emissions sources upstream of the processing plant have, to date, focused on VOCs or HAPs, with reductions of methane emissions seen as co-benefits.[28] After processing, natural gas is roughly 95 percent methane, on average, and leaks and vents of natural gas release far fewer non-methane pollutants.[29] Therefore, to ensure deep reductions of methane emissions, it is critically important to target methane directly, because the current focus on VOCs or HAPs misses many significant sources of methane emissions in the transmission, storage, and distribution segments of the value chain.

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Table 1 | Major Emissions Sources by Supply Chain Segment

EMISSIONS SOURCE	PREPRODUCTION AND PRODUCTION	PROCESSING	TRANSMISSION	DISTRIBUTION
Reciprocating Compressors	✓	✓	✓	
Centrifugal Compressors		✓	✓	
Pneumatic Devices	✓	✓	✓	
Liquids Unloading	✓			
Equipment Leaks	✓	✓	✓	✓
Engines	✓	✓	✓	
Pipeline Vents			✓	

Policies that target methane-emissions reductions directly are good for the climate and local environment, but they can also be good economics.[30] Consider the following:

Reducing the waste of a valuable commodity pays dividends for companies in the form of higher revenues, and investments in emissions-control technologies often pay for themselves in three years or less, as discussed in more detail below.[31]

Reducing methane emissions creates high-quality jobs, because dozens of companies manufacture emissions-control equipment in the United States.[32]

In the case of natural gas operations on public lands, reducing leaks and vents of natural gas means more royalties and a better value for taxpayers.[33]

Reducing natural gas leakage to one percent or less of total production is an achievable and cost-effective[34] benchmark for the near term, and ensures that natural gas is less climate-intensive than its substitutes for all end-uses, namely diesel fuel and gasoline in the transportation sector, and coal in electricity generation.[35] A number of regulatory, legislative, and incentive-based approaches are available to policymakers and to businesses to help the U.S. natural gas industry achieve this benchmark. Which approach makes the most sense can vary by emissions source, the severity of the problem, or local conditions that might pose implementation challenges, including resource, legal or political issues.

In this working paper, we examine the major sources of methane emissions from the production, processing, transmission, and distribution of natural gas (see Figure 1), as well as the technologies and procedures available now to reduce their negative environmental and climate impacts. Studies indicate that a small percentage of sources might be responsible for a large percentage of methane emissions.[36] The varying nature of methane emissions from natural gas systems means that there is no "one size fits all" approach that will work in every instance. However, policy solutions based on established best practices can effectively address each of the problems we discuss below.

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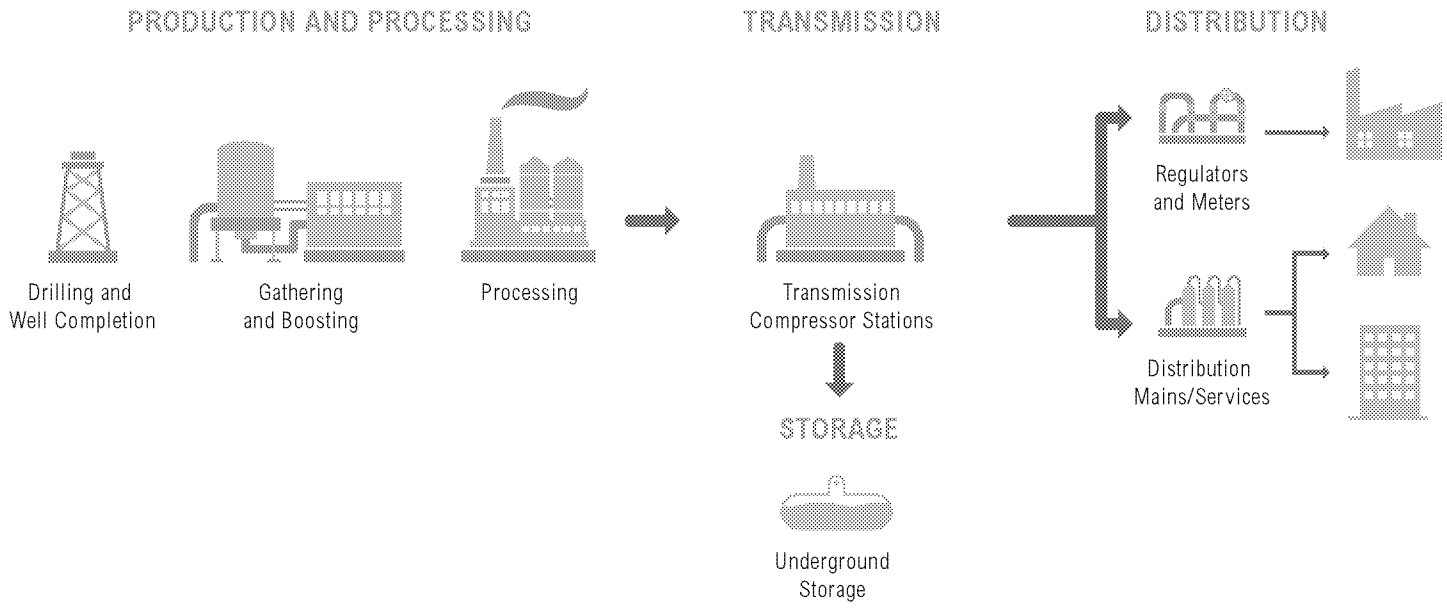
Box 1 | Potential National Methane Standards from EPA

On March 28, 2014 the Obama Administration announced its "Strategy to Reduce Methane Emissions" as part of the president's Climate Action Plan.[1] Along with updating standards for methane emissions from landfills, and potential new requirements for capturing and selling methane from coal mined on public lands, the president directed EPA to consider new standards for methane emissions from oil and gas development. Unlike the earlier New Source Performance Standard (NSPS), which addressed VOC emissions but reduced methane emissions as a co-benefit, these new standards would target methane directly, most likely under Section 111 of the Clean Air Act.[2]

Several weeks later, EPA released a series of white papers for public comment, covering methane emissions from compressors, well completions, leaks, liquids unloading, and pneumatic devices.[3] These white papers, along with stakeholder comments, are likely to form the basis of new emissions standards that will, according to EPA, be proposed in the second half of 2015. At the time of publication of this working paper, EPA had not yet announced a decision on which of these sources, if any, would be addressed via new rules, nor how stringent those rules should be. What the administration has said is that these rules will target only new and modified infrastructure and that, together with voluntary efforts, they will reduce methane emissions from the oil and gas sector by 40-45 percent below 2012 levels by 2025.

While more stringent federal standards would necessarily supersede weaker state standards for the same emissions source, states nevertheless need to move forward with crafting their own methane rules for the emissions sources discussed in this working paper. This is because, first and most importantly, the forthcoming emissions standards from EPA focus exclusively on new and modified infrastructure, and will miss a substantial fraction of total emissions from old and leaky equipment. Second, as mentioned above, many if not most of the technological solutions available for addressing these sources are cost effective and pay for themselves in three years or less.[4] Third, under Section 111, states are required to implement and enforce compliance with any federal emissions standard that EPA may propose. By embarking on the learning curve before federal rules are finalized, states can reduce any potential compliance costs borne by companies operating within their borders. Lastly, we don't yet know how stringent any of EPA's new rules will be, and it is unlikely that they will cover all of the emissions sources discussed in this working paper, providing states the opportunity to help reduce waste and save money for the natural gas industry and consumers.

Figure 1 | The Natural Gas Supply Chain



Source: http://www.epa.gov/ghgreporting/images/subpart_w_chart.jpg.

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We have chosen to make policymakers at the state level, including state legislators, public utility commissioners, and other regulatory agencies, the primary focus of the recommendations in this working paper. States have a traditional role as "laboratories of democracy," whereby successful policies at the state level are emulated in other states and at the federal level.[42] In addition, it will be important for states to go beyond EPA's proposed standards for new and modified equipment if they are to address the substantial emissions from existing infrastructure. As of this writing, EPA is considering regulating methane from major sources under Section 111 of the Clean Air Act.[43] Under this framework, EPA sets state-level targets, and then works with states to find ways in which the targets can be met (see Box 2 for more details).[44]

Box 2 | EPA Rules Draw on State Experiences

In 2012, EPA promulgated an NSPS that addressed one of the largest sources of methane and VOC emissions in the production segment, namely, natural gas well completions.[45] In brief, well completion is the process by which a drilled well is made ready for the production of natural gas, and the flow of natural gas exceeds drilling and other fluids. Throughout this process, natural gas has traditionally been vented to the atmosphere or flared. However, EPA's NSPS requires new and fractured wells to reduce VOC emissions from well completions. Well operators were allowed to meet this requirement through fading until January 2015; now, most natural gas vented during completions must be captured a process called "green completion."

EPA's decision to target well completions did not happen in a vacuum. Rather, the agency followed the successful implementation of similar rules in both Wyoming and Colorado. Wyoming, for example, had been mandating green completions in most instances since 2004, requiring that well operators divert gas that would otherwise have been vented into sales lines.[46] This proof of concept at the state level provided EPA with rules it could build on and served as the basis for the national emissions standards issued in 2012.[47]

States have long served as laboratories and proving grounds for policies that later get adopted by other states and by the federal government. States that implement strong measures to reduce methane emissions from natural gas development also have the advantage of shortening the learning curve if and when methane emissions are regulated at the national level. Companies active within these states with ambitious methane reduction measures will be better prepared to meet national standards, and will likely benefit from lower compliance costs and increased returns on investment in emissions reduction training and equipment.

This working paper builds on earlier work by WRI, as well as studies from the Environmental Defense Fund, Natural Resources Defense Council, academic researchers, ICF International, the National Oceanic and Atmospheric Administration, EPA, and others. It presents a clear overview of what is known about methane emissions from natural gas systems and how they can be mitigated. Through case studies and descriptions of best practices, this working paper proposes recommendations for new rules. This paper can help EPA and states determine how best to structure future policies to reduce methane emissions from natural gas development.

EMISSIONS REDUCTION OPPORTUNITIES DURING THE PREPRODUCTION AND PRODUCTION STAGES

Drilling wells, preparing them for production, ensuring a steady flow of gas, and transporting the gas from the wellhead to the processing plant involves a number of procedures and pieces of equipment that can emit significant quantities of methane if not adequately addressed. In this section, we will examine some of the largest sources of those emissions at this first stage of the natural gas supply chain and recommend policies that states can put in place to ensure the use of best practices.

Reciprocating Compressor Seals

Compressors increase pressure to move natural gas from the well all the way to the city gate; they are used in the production stage of the supply chain to move gas through gathering lines to the processing plant.[48] Many compressors are powered by the natural gas that flows through the lines they are pressurizing, which opens the door to unintentional vents and leaks from seals, valves, gaskets, and other components.

Two primary types of compressors are used at various points in the natural gas supply chain. In the production stage, reciprocating compressors are the most common, and so are discussed here; centrifugal compressors are more common in the processing and transmission stages, and are discussed below.[49] Reciprocating compressors work by using pistons on a crankshaft to compress natural gas, thereby increasing pressure and facilitating the movement of gas along gathering or boosting lines.

EPA's NSPS requires regular maintenance of new reciprocating compressors at gathering and boosting stations and

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processing plants to reduce methane emissions. Operators must replace rod packing systems, which can wear down and leak methane, every 36 months or 26,000 hours of operation. However, the NSPS does not apply to existing compressors.[50] Reciprocating processors in the production stage were the source of around 46,000 metric tons of methane emissions in 2013, or 1.5 million metric tons of CO_2 equivalent.[51,52] While this is only around 2.5 percent of all production emissions, the NSPS and other sources demonstrate that regular compressor maintenance is good business practice. Replacing rod packing systems at reciprocating compressors on gathering and boosting lines every three years costs between $4,000 and $7,000, and saves an average of around 400,000 cubic feet (400 Mcf) of natural gas per compressor per year.[53] At natural gas prices of $4.50 per Mcf, slightly higher than the average daily spot price for 2014, a policy requiring compressor maintenance every year and rod packing replacement every three years would pay for itself in added revenue.[54]

Pneumatic Devices

Pneumatic devices, powered by natural gas, regulate various aspects of the gas passing through them, including temperature, pressure, and flow rate. Many pneumatics are powered by natural gas under high pressure, and vent (or "bleed") some of that gas to the atmosphere as part of normal operations. High-bleed pneumatic devices are a significant source of methane emissions throughout the supply chain, but low-bleed and no-bleed substitutes are currently available.

As with compressors, the EPA NSPS addresses emissions only from new pneumatic devices, not from existing equipment. Yet existing devices number over half a million and are a significant source of methane emissions.[55] According to EPA Inventory data, in 2013, pneumatics emitted roughly 638,000 metric tons of methane, over 20 million metric tons of CO_2 equivalent, or a full one-third of all methane emissions from the production sector.[56] It should be noted, however, that at least one study suggests that EPA might be underestimating these emissions by over 40 percent.[57]

Replacing or retrofitting a continuously or intermittently emitting high-bleed controller—defined as emitting an average of over six standard cubic feet (scf) per hour as part of normal operations—can make economic sense even if the device is not yet at the end of its useful life.[58] With retrofit and replacement costs ranging from a few hundred to a few thousand dollars, respectively, low-bleed pneumatic devices can pay for themselves through increased revenues in three years or less.[59] An alternative solution that eliminates methane emissions altogether is to replace gas-driven pneumatic devices with ones that rely on compressed air or electricity instead, as is common in processing plants and at some production facilities with access to the electric grid or on-site electricity generation.[60] Despite a more significant up-front investment, instrument air devices are also reported to reduce quantities of leaked natural gas by amounts sufficient to pay for the devices in two years or less.[61]

Box 3 | Pneumatic Devices in Colorado

Colorado had rules in place in 2014, well before the EPA NSPS was first proposed, that required the use of low-bleed pneumatics at new installations, and the replacement or retrofitting of existing high-bleed pneumatics to bring their emissions down to levels achieved by low-bleed pneumatics.[a] However, these rules targeted VOCs, and applied only in areas with high levels of ground-level ozone, or smog.

In 2014, these same standards were updated to apply statewide, and while they still target VOCs, they still have significant methane co-benefits.[b] With very few exceptions, low-bleed or no-bleed pneumatics must be installed at new installations, and high-bleed pneumatics must be replaced or retrofitted by May 2015. In areas where grid electricity is available, no-bleed pneumatics, which are powered by compressed air or electricity and do not vent natural gas to the atmosphere as part of normal operations, can be used to comply with this requirement.

While Colorado's requirements for pneumatic devices set an example for other states and the federal government to follow, they can be strengthened still further without sacrificing cost-effectiveness. Because they target VOCs, Colorado's rules apply only to pneumatic devices downstream of the processing plant—that is, only within the production segment of the natural gas supply chain. However, pneumatics are used throughout the supply chain, including downstream of the processing plant where VOC concentrations are lower. States should expand Colorado's standards to all pneumatic devices and ideally they target methane directly in order to capture all high-bleed devices.

Liquids Unloading

Over time, water and other fluids (including natural gas liquids, like propane) can accumulate in natural gas wells, reducing pressure in the well and impeding the flow of natural gas. To increase the production of a mature well, these liquids can be removed (or "unloaded") in a number of ways, many of which lead to intentional or uninten-

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tional venting of natural gas to the atmosphere. One such method, well blowdowns, involves shutting in the well, allowing pressure to build, and then opening the valve at the surface to drive the liquids from the wellbore (while venting gas to the atmosphere). However, this method is often a temporary fix, doing little to solve the underlying problem of accumulated liquids, and leading to lower production over the lifetime of the well.[64]

As is the case with many other sources in the natural gas supply chain, methane emissions from liquids unloadings appear to follow a "fat-tail" distribution, in which a small fraction of wells with more frequent unloadings are responsible for a large fraction of emissions.[65] The 2015 EPA Inventory estimates that unloadings—both with and without plunger lifts—accounted for over 259,000 metric tons of methane emissions in 2013, or 14 percent of emissions from the production segment of the natural gas life cycle;[66] this is in line with estimates from the Greenhouse Gas Reporting Program from that year.[67] Yet both of these estimates use emissions factors from an industry survey, not an independent analysis that includes a representative cross-section of the natural gas industry; they therefore should be taken as a conservative estimate.[68]

Several techniques use energy from the well or from outside sources to lift the liquids to the surface, increasing the flow and production of natural gas without unnecessary venting.[69] For example, plunger lifts use the pressure within the well to depress a plunger to where liquids are accumulated, pushing them up to the surface.[70] Plunger lifts have proven to be extremely cost-effective in many instances, especially when used correctly and when venting is minimized, with payback periods of less than one year.[71] And if an external power source is available, artificial lifts that are powered by electricity instead of the well's internal pressure can be used to pump liquids to the surface, reducing the need for extraneous venting.[72] Because artificial lifts have proven to be more effective at removing liquids with few to no methane emissions (though the equipment does generate some emissions of carbon dioxide), they should be used at wells being unloaded for the first time, and for all subsequent unloadings, if feasible.[73]

Equipment Leaks

Equipment leaks cut across all major segments of the industry (production, processing, transmission, and distribution), and overlap with many other major source categories (such as compressors, described above). Traditionally, the category of leaks has been defined to include unintentional emissions from a variety of equipment, including connection points such as flanges, open-ended lines, fittings, and moving parts of valves, pumps, and compressors.[74] The category does not include intentional venting of gases, such as venting from well completions and liquids unloading.

In this section we take a broad definition of LDAR and discuss how policy responses focused on equipment leaks can also aid in the detection of excessive emissions from equipment across all source categories.

Existing national regulation (EPA NSPS) requires leak detection and repair for certain components including pumps, valves, and pressure-relief devices at new natural gas processing facilities.[75] The recent update to the EPA standards tightened the LDAR requirements for processing plants by lowering the detection limit of leaking gas from valves from 10,000 to 500 parts per million, and added connectors to the list of components to monitor. The rule was based on analysis showing that LDAR programs were most cost-effective at natural gas processing facilities (using EPA's leak detection protocol, Method 21—see below).

As recently documented by EPA's White Paper on the topic, a wide range of evidence is available that demonstrates the pervasiveness of equipment leaks throughout all segments of the natural gas system.[76] This evidence includes mandatory reporting data, studies of voluntary LDAR programs, and measurement campaigns. In general, the balance of evidence shows that gas processing plants have the highest leak rates, followed by compressor stations and well production sites, and that a large proportion of total emissions (approximately 80 percent) comes from a small proportion of leaks (approximately 20 percent).[77] Importantly, the current state of knowledge suggests that these disproportionately large leaks are not related to any specific types of operators or operating parameters,[78] meaning that widespread LDAR can be highly cost-effective, and is needed throughout the industry to find and fix these "super emitters."

While a wide variety of equipment is available for implementing LDAR, federal and state policymakers have focused mainly on two methods: portable analyzers (also called EPA Method 21) and optical gas imaging (OGI, also known as infrared imaging). While OGI devices have a much higher capital cost (around $85,000 *versus* $10,000 for a portable analyzer),[79] they can monitor equipment at a much higher rate than is possible with portable analyzers. This allows their higher upfront cost to be spread across a number of facilities, and opens the door to alternative

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business models such as renting equipment or purchasing leak detection services from third parties. OGI has other advantages. For example, it can monitor inaccessible components (such as storage tanks) at a distance and find leaks quickly in places where surveyors may not have thought to look, such as underground pipelines outside of processing plants. On the other hand, unlike portable analyzers, OGI devices cannot definitively identify the gases that are leaking or quantify the size of leaks, only detect them.

The cost-effectiveness of LDAR programs using either technology depends on a number of factors, including the amount and value of gas that otherwise would have leaked, and the cost of the program (equipment, training and labor for leak detection, plus the cost of repairing the leaks). The available evidence shows that it is cost-effective to repair the vast majority of leaks, and the cost of conducting the surveys is the primary hurdle for either voluntary or regulatory LDAR programs.[80]

A critical parameter is how often facilities conduct these surveys. Too few surveys per year will allow valuable gas to escape, but too many could result in only marginal improvements in emissions reductions. Recent work analyzing thousands of LDAR surveys has shown that the sweet spot is likely to be between monthly surveys and semiannual surveys, depending on the life-cycle segment, size of the facility, potential for emissions, existing maintenance programs, and other factors.[81] Critically, most of the available evidence on cost-effectiveness is related to facilities already performing regular LDAR. Since equipment leaks seem to follow the 80/20 rule, this suggests that, on average, the cost-effectiveness of regular LDAR regimens will be much greater at facilities not yet performing regular LDAR. It is likely that operators currently conducting regular LDAR surveys have fewer and smaller leaks than those who are not, because they have been detecting and fixing leaks all along.

We should note that significant efforts are underway to improve and reduce the cost of technology for leak detection. For instance, vehicle-mounted monitoring at the site level is a relatively recent innovation, giving operators the opportunity to take a rough scan of a facility before deciding whether to conduct a full leak survey, saving time and money if the potential emissions sources are well maintained and not leaking.[82] Further, the MONITOR program of the Advanced Research Projects Agency-Energy (ARPA-E) and the Environmental Defense Fund's Methane Detectors Challenge are likely to lead to new and more cost-effective leak detection technologies in the 5–10 and 2-3 year timeframe, respectively. These developments imply that policies should be both open to new technologies and designed based on the cost-effectiveness of LDAR today, which will lead to even more cost-effective LDAR in the future.[83]

As discussed above, existing regulations for VOCs and hazardous air pollutants are in place for natural gas processing facilities and provide methane reduction co-benefits. However, leaders in both Colorado and Wyoming have gone beyond these national requirements to require LDAR at upstream production facilities as well, and recent Colorado regulations also require LDAR at upstream compressor stations and for storage vessels.[84] Both states allow use of either OGI or Method 21 approaches.

Box 4 | Four States Take the Lead on Leak Detection and Repair

In February 2014, with support from some of the largest natural gas companies in the state, Colorado finalized new rules mandating LDAR at well sites, gathering compressor stations, and storage vessels.[85] The inspection frequency varies from monthly to annually for most facilities, depending on the type of equipment and the potential emissions from the site.[86] This flexibility helps keep compliance costs down while ensuring that the sources of the largest potential leaks—and therefore the ones most cost effective to repair—are monitored more frequently than sources that are less likely to be major emitters. The new rules require all leaks to be repaired within five days, unless parts are unavailable or shutdown is required to fix the leak. In the former case, companies are given 15 days to repair the leak and to prove that the leak was fixed after 15 days. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.[87]

In developing its LDAR rules for production facilities, compressor stations, and storage tanks, Colorado learned from the experiences of Pennsylvania and Wyoming in requiring regular leak detection and repair surveys—[88] just two months after Colorado finalized its rules, and five months after they were first proposed in November 2013, Ohio followed suit with new LDAR requirements of its own.[89]

This example illustrates how states can learn from one another, even if they do not directly collaborate on developing rules. Similarly, other states can follow the examples of Pennsylvania, Ohio, Colorado and Wyoming, strengthening the rules where appropriate (for example, increasing the frequency of leak inspections) to better protect human health, the local environment, and the climate.

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Table 2 | Key Recommendations for Production Stage Policies

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[91]
Reciprocating Compressors		19
Seals	Replace rod packing systems every three years at existing compressors along transmission lines and on gathering and boosting lines, and require annual maintenance to ensure good working order. When appropriate measurement technology is available, states should ensure that emissions from reciprocal compressors are reduced to 11.5 standard cubic feet (scf) per hour—the average emissions from newly installed rod packing.[92] As an alternative compliance option, states could require the capture of leaking natural gas and its re-routing back into the compressor engine, to be combusted to power the compressor.	
Static Components	States should also require regular leak detection and repair (LDAR)[93] for compressors along gathering lines and at processing plants.	
Pneumatic Devices	States can go beyond the requirements set forth in Colorado's new rules targeting pneumatics by requiring the following: ■ retrofits of continuously or intermittently emitting high-bleed pneumatics (that is, devices that vent significant quantities of natural gas as part of their normal operations) with no-bleed or low-bleed equivalents as soon as practical, to bring their emissions down below a low-bleed threshold of six scf per hour,[94] ■ regular LDAR to identify excessively emitting equipment, which can be repaired or replaced, and ■ all new and replacement controllers upstream of the processing plant to be powered by compressed air or electricity instead of compressed gas when access to the electric grid is available, and with low-bleed pneumatics when it is not.	12
Liquids Unloading	Where external power sources or high-pressure gas are available, an artificial lift—powered either by electricity or gas—should be used during every unloading event. When external power sources are not available, plunger lifts should be used during every unloading event. Because plunger lifts have been demonstrated to reduce methane emissions by 95 percent or more when used properly, well operators should be required to use plunger lifts and avoid venting wherever feasible.[95] States should ensure that well operators are trained in best practices in order to maximize emissions reductions from liquids unloading events.	4
Equipment Leaks	States should require two-stage LDAR for all production facilities, processing plants, compressor stations, and large, above-ground distribution facilities. Mobile air monitoring—whereby air-sampling technology is mounted to a vehicle to check for high concentrations of methane—should be performed at least quarterly. States should phase in this requirement to allow companies to purchase or lease the appropriate emissions-monitoring equipment. A complete leak detection survey using optical gas imaging (OGI) or portable analyzers should be performed semi-annually to ensure that all leaks are detected. When mobile monitoring detects methane or VOC levels higher than background levels, follow-up OGI or portable analyzer screenings should be performed to locate the source of the leak. Once discovered, leaks should be repaired within five calendar days if possible. If the leak cannot be repaired within five days, either because needed parts are unavailable or because facility operations would need to be shut down, then repairs must be made within 15 calendar days, or as soon as practical.[96] Companies should report the results of their mobile monitoring surveys to the state, which can make those reports public, and state officials should ensure that all leaks have been repaired by performing spot checks of production, processing, and transmission facilities within their borders.	19[97]

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EPA currently requires LDAR at new processing plants. However, expanding these standards to cover existing processing plants, as well as new and existing compressor stations and production and gathering facilities, is an important step toward reining in both methane and VOC/HAP pollution. As the Colorado rulemaking shows, LDAR can be a cost-effective measure in all segments of the natural gas production chain, and it is likely that its cost-effectiveness is higher for existing facilities where maintenance issues can be more frequent or problematic than at new facilities.

That said, it is important for state decision-makers to design policies that are flexible enough to accommodate the likely innovation coming soon in natural gas leak detection. An intriguing possibility today is the concept of two-stage LDAR, where initial mobile monitoring is used at production, processing, and transmission facilities to identify whether natural gas is leaking, followed by full LDAR at positively identified sites to pinpoint exactly where those leaks are occurring. Two-stage LDAR can be a highly effective method for reducing methane emissions, and rules should be designed to maximize reductions while keeping compliance costs in check. This could entail requiring mobile monitoring at a relatively high frequency (for example, monthly or quarterly) and full LDAR using OGI or Method 21 less frequently (annually or semiannually), and only when sites are identified as leaking by mobile monitoring. Further, while LDAR is cost-effective today, regulations should not be overly prescriptive about technology. Room must be left for future innovative monitoring and leak detection technologies to emerge as alternative compliance mechanisms.

EMISSIONS REDUCTION OPPORTUNITIES DURING THE PROCESSING STAGE

After production, unprocessed natural gas is moved along gathering lines from the wellhead to a central processing plant. When it comes out of the ground, natural gas is typically between 70 and 95 percent methane, meaning up to 30 percent of unprocessed natural gas can be liquids or gases that alter the energy content or reduce the purity or value of the natural gas.[98] For example, water and hydrogen sulfide can corrode pipelines, and gases like nitrogen reduce the energy content of natural gas. In addition, processing separates out natural gas liquids like propane and butane—valuable by-products that are sold separately from the natural gas itself.

Processing plants often use reciprocating compressors, and a variety of other equipment, that can leak if not maintained properly; policies to address both of these sources were discussed in the preceding section.

Centrifugal Compressors

Much larger than reciprocating compressors, centrifugal compressors nevertheless serve much the same purpose, namely, ensuring that natural gas remains pressurized so that it will move quickly through pipelines. The primary source of methane emissions from centrifugal compressors is from seals around the rotating shaft, which are designed to prevent gas from leaking. However, there are two types of seals—wet and dry—and wet seals have been found to leak considerably more than dry seals.[99] Wet seals use oil as a barrier to prevent the leakage of natural gas from the compressor; however, pressurized gas is absorbed by the oil, rendering it less effective as a barrier.[100] Contaminated oil is re-circulated, at which time the absorbed gas is vented to the atmosphere, flared, or re-routed back into the processing plant to remove accumulated impurities. By contrast, dry seals are mechanical and do not use oil, which leads to fewer and smaller leaks, as well as lower operating costs for plant owners.[101]

EPA's 2012 NSPS requires new and modified wet seal centrifugal compressors at processing plants to reduce VOC emissions by 95 percent,[102] which should lead to concomitant reductions in methane emissions. However, the rule does not cover existing centrifugal compressors, which are, and will continue to be, major sources of methane emissions at processing plants. According to the 2015 EPA Inventory, centrifugal compressors were responsible for as much as 283,000 metric tons of methane emissions in 2013 (10.2 million metric tons of CO_2 equivalent), nearly 85 percent of which came from compressors with wet seals.[103] However, information from EPA's Greenhouse Gas Reporting Program suggests that the emissions factor for wet seal compressors used in the Inventory may be a significant underestimate, and actual emissions could be much higher.[104]

Wet seal centrifugal compressors are more prevalent than dry seal compressors. According to the 2015 EPA Inventory, wet seal compressors make up 80 percent of the centrifugal compressors in the processing and transmission life cycle stages.[105] Operators of wet seal compressors have two available options to reduce methane emissions: retrofitting with dry seals, or installing equipment to capture and re-route gas that would otherwise be vented or flared. Retrofitting with dry seals can be expensive, but has

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been shown to produce positive returns on the initial investment within three years.[106] Gas capture systems have proven to be even more cost-effective.[107] Both options can reduce methane emissions from wet seals by 85 percent or more.

Reducing methane emissions from seals is a necessary but not sufficient step in addressing emissions from compressors as a whole. In addition to emissions from seals, which can be addressed through the measures described above, centrifugal compressors can leak potentially significant amounts of natural gas from valves and other components.[108] For this reason, best practice is to combine any actions to reduce emissions from wet seals with a rigorous LDAR program, to ensure that all major leaks are found and fixed within a reasonable amount of time.

Engines

Gas-burning engines are used throughout the natural gas supply chain to power compressors and other types of equipment, including reciprocating and centrifugal compressors at processing plants and at compressor stations along transmission pipelines. Unburned natural gas is often vented to the atmosphere, because of incomplete combustion, which occurs especially during engine startups.

Methane emissions associated with gas engines at processing plants totaled nearly 300,000 metric tons in 2013, or roughly 10.7 million metric tons of CO_2 equivalent.[109] If natural gas production and associated emissions continue to grow over the coming years, leaked and vented natural gas from engines throughout the natural gas supply chain could reach over 22 billion cubic feet (nearly 500,000 metric tons of methane) by 2018—worth approximately $100 million at average daily spot prices in 2014.[110]

While chemical solutions exist to reduce much of the air pollution associated with uncontrolled natural gas emissions from engine exhaust (for example catalytic reduction or oxidation), such measures unfortunately do not prevent methane from venting to the atmosphere.[111] However, mechanical solutions are available to help reduce unnecessary venting from engines. For example, replacing pressurized natural gas used in engine start-ups with compressed air or nitrogen can reduce methane emissions from vented natural gas, as well as leaks from storage tanks.[112] Alternatively, using an electric motor instead of a natural gas engine can avoid methane emissions from engine start-ups altogether.[113]

Table 3 | Key Recommendations for Processing Stage Policies

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[114]
Centrifugal Compressors		9
Seals	Performance standard of six scf per minute for all existing centrifugal compressors, which represents the average emissions factor for dry seal systems, and an 87 percent reduction below typical emissions levels from wet seal systems.[115] This standard can be met either by replacing wet seals with dry seals, or capturing gas leaked from wet seals (to be re-routed back to processing and later sold), the latter of which can reduce vented methane emissions from de-gassing seal oil by up to 99 percent.[116]	
Static Components	In conjunction with measures to reduce emissions from wet seal centrifugal compressors, all compressors should be subject to a rigorous LDAR program. As described above, and in greater detail below, states should implement a two-stage program, to increase the effectiveness of performing LDAR without burdening industry with unnecessarily high costs.	
Engine Exhaust	When an electric power supply is available from the grid, or on-site distributed generation is feasible, electric motor starters should be used for all engine start-ups. When this is not the case, gas starters should either be replaced with air or nitrogen, or operators should capture the gas used in the starters. As with centrifugal compressors, engines should be included in all LDAR surveys.	11

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EMISSIONS REDUCTION OPPORTUNITIES DURING THE TRANSMISSION STAGE

The transmission segment of the natural gas supply chain includes interstate and intrastate pipelines, as well as compressor stations that help maintain the pressure of the natural gas inside those pipelines. Compressor stations contain much of the same equipment that we have discussed already, including reciprocating and centrifugal compressors, engines, and pneumatic devices. This equipment is a major source of emissions at compressor stations, as it is elsewhere. (See the Production and Processing sections of this working paper for more information on emissions sources earlier in the natural gas supply chain.)

Pipeline Venting

When pipeline operators need to perform maintenance on sections of their lines, they must first reduce the pressure inside, and remove gas from, the pipeline in order to reduce the risk of explosion. This is often achieved by simply venting the gas in the relevant pipeline section into the atmosphere. However, there are several methods for reducing pipeline pressure that result in significantly lower methane emissions, discussed below.

In 2013, pipeline venting for routine maintenance was responsible for 125,000 metric tons of methane emissions, or 4.5 million metric tons of CO_2 equivalent.[117] While pipeline vents are a less significant source of emissions than many others discussed in this working paper, cost-effective emissions reduction opportunities are available today that make sense in most instances.

When a section of pipeline is taken offline for planned or emergency maintenance, the natural gas in that line can be "pumped down" with in-line compressors—essentially moving enough gas out of the pipeline section to reduce pressure to safe levels. This method has been demonstrated to achieve emissions reductions approximately 50 percent below what they would be through venting alone.[118] And portable compressors that maintenance teams can bring to the pipeline segment in question can move even more gas out of the line, reducing pressure further and achieving emissions reductions on the order of 90 percent.[119] Both of these measures have immediate to near-immediate payback periods.[120]

EMISSIONS REDUCTION OPPORTUNITIES DURING DISTRIBUTION

Transmission pipelines deliver natural gas to end-users (such as power plants) as well as local gas utilities, which are responsible for distributing the gas to residential and commercial consumers. The distribution network is made up of larger pipelines, called mains, and smaller service lines that branch off of mains to deliver gas to homes and businesses. Unlike most transmission pipelines, many distribution lines are old and leaky. Cast iron and bare steel—the primary materials used for decades in building natural gas distribution networks, especially in the first half of the last century—have been shown to leak considerable amounts of gas as they age.[121] Newer materials, including plastic and steel coated with materials to prevent corrosion, are being used by utilities across the country to replace these older pipelines and reduce the incidence of

Table 4 | Key Recommendations for Transmission Stage Policies

SOURCE OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[122]
Pipeline Venting	For planned maintenance, pipeline operators must use portable compressors—either alone or in conjunction with in-line compressors located at the compressor station—to reduce pipeline pressure to 90 percent below normal operating levels. For emergency repairs when there is not enough time to secure a portable compressor, maintenance teams should use in-line compressors to reduce pipeline pressure to 50 percent below normal operating levels (if doing so does not present a safety hazard).	3

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gas leaks, which can be dangerous to people and property as well as harmful to the environment.

However, thousands of miles of cast iron and bare steel pipelines remain beneath city streets. With replacement costs on the order of half a million dollars per mile or more, pipeline replacement programs are expensive.[123] Because costs are so high, natural gas utilities prioritize fixing leaks and replacing old pipes that pose risks of explosions or other hazards. Many utilities do have programs in place to replace all cast iron and bare steel pipelines in their networks, but some of these programs will not achieve the complete elimination of cast iron pipes for decades.[124] Moreover, because measures to reduce distribution leaks do not usually pay for themselves through increased natural gas sales alone, unlike many of the practices outlined above, utilities typically recover the costs of pipeline replacement programs from their consumers, through rate increases or surcharges. Because state regulators in most instances need to approve any cost-recovery programs, it can be difficult to accelerate pipeline-replacement programs. However, because of the dominant role of state public utility commissions and other regulators in overseeing the natural gas distribution system, states can do much to reduce methane emissions from distribution networks.

Currently, most states require the classification of distribution leaks into one of three tiers: those that pose an imminent danger and require immediate attention (Tier 1), those that pose some risk and should be fixed within a reasonable amount of time (Tier 2), and those that do not pose much risk but should be monitored on a regular basis (Tier 3).[125] Large leaks that do not pose a risk to people or property do not require an immediate fix, even though they may be emitting significant quantities of methane. To reduce emissions, state regulators can create a fourth tier for such leaks—below Tier 1 but above Tier 2—requiring that these leaks be fixed as soon as practicable.

California has taken steps to put such a system into practice. Senate Bill 1371, approved in September 2014, charges the state's Public Utilities Commission with finding ways to require natural gas distribution utilities to locate and repair leaks.[126] S.B. 1371 targets large leaks that do not necessarily pose a health or safety risk, but would require "the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components...within a reasonable time after discovery."[127] California is positioning itself ahead of the curve in identifying and repairing leaky distribution infrastructure, and could serve as an example for other states to follow.

Table 5 | Key Recommendations for Distribution Stage Policies

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES
Pipeline Replacement Programs	State regulators should allow for accelerated pipeline replacement programs, which would likely require higher prices for gas customers. Regulators should ensure that lower-income households are not adversely affected by any price increase.
Leak Reclassification	State legislators or regulators should work with natural gas utilities to modify the existing system of leak classification, which does not assign a high priority to repairing large leaks that do not pose a threat to people or property. Such leaks should be categorized as Tier 2, and should be repaired within a reasonable amount of time (for example, three months or less).
Leak Inspection	Utilities should be required to use vehicle-mounted emissions-detection equipment to survey their entire network at least twice per year.
Meter Replacement	Residential and commercial meters should be tested for accuracy at least once every seven years.[128] If flow accuracy is found to have fallen below 98 percent, the meter should be replaced.

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To detect leaks, utilities perform regular inspections of gas mains and service lines, and rely on the public to notify them whenever they smell natural gas in their home or office. Performing regular inspections often entails using hand-held hydrocarbon sensors while following the path of the subterranean pipelines. However, new vehicle-mounted technology allows for quicker and more accurate inspections.[129] States should require the use of vehicle-mounted emissions detection equipment, and mandate more frequent surveys to ensure that leaks of all sizes are monitored and repaired as quickly as possible.

Lastly, states can contribute to progress in improving the accuracy of residential and commercial meters. Currently, natural gas distribution utilities are allowed to recover the cost of any gas that is "lost and unaccounted for." This category includes pipeline leaks, but it also accounts for differences in sensitivity between highly accurate meters at the end of the transmission pipeline and the less accurate meters at homes and businesses, which can slow down over time. Because it is nearly impossible to determine how much gas falls into the latter category, state regulators allow utilities to pass on to consumers the cost of lost and unaccounted for gas. However, more accurate residential and commercial meters could help reduce the amount of gas that is written off as "unaccounted for," and help companies identify with more precision how much gas is leaking throughout their system. To that end, states can require that companies replace older meters—which slow down as they age—with more accurate ones, though this is unlikely to be a cost-effective solution. As an interim measure, utilities can test the accuracy of a subset of meters, and apply that flow factor across the entire set of meters in their service area to better estimate the "unaccounted for" gas.[130]

CONCLUSION

States can lead the way on reining in methane emissions from natural gas development. Thirty-three states currently produce natural gas and, while Colorado is currently the only state with rules directly targeting methane emissions, others—including Wyoming, Pennsylvania, and Ohio—have taken steps to address other pollutants that will also have the effect of reducing methane emissions.[131] State rules have helped to shape federal emissions standards, and momentum is building as states learn from one another and companies share best practices.[132] Yet both states and the federal government are still playing catch-up, because the rapid increase in natural gas production in the United States over the past decade has far exceeded the efforts of states and the federal government to impose common-sense emissions standards that protect human health and the environment without unduly burdening industry.

Using the policy and technology solutions identified in this paper, states can continue to make progress on mitigating the climate and public health impacts of natural gas development. As we have discussed, opportunities exist at every stage of the natural gas life cycle, from preproduction through distribution. But proactive government policies are needed to ensure that emissions-reduction opportunities are capitalized upon, ensuring that the potential climate advantage of natural gas—its relatively low carbon content—is not undermined by unnecessary emissions of methane.

While state-level and national emissions standards for methane will be the most effective way to ensure deep reductions in methane emissions, investors, shareholders, and companies can also be an important part of the solution. Investors and shareholders can insist upon a commitment to using proven best practices, including those listed in this working paper. And companies can lay the groundwork for ambitious standards by demonstrating that reducing emissions and turning a profit do not have to be mutually exclusive.

Natural gas can play a part in helping the United States meet its near-term climate goals, but only if methane emissions are brought under control. The natural gas industry must also preserve its social license to operate, which depends on the goodwill of local residents who are impacted by drilling, by ensuring that operations do not pollute air or water, cause earthquakes, strain water supplies, or otherwise damage the local environment. The good news is that the technologies to address emissions from all sources along the supply chain are available, and are among the most cost-effective greenhouse gas emissions-reduction measures available. We know the types of policies that will encourage greater utilization of emissions-control technologies and best practices, and that can bring methane emissions below one percent of total production. Strong state standards can help lead the way.

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ENDNOTES

1. Arkansas, for example, saw its natural gas production increase six-fold between 2005 and 2013, while Pennsylvania's production increased nearly twenty-fold over that period. For more information, see: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

2. Methane lasts between roughly nine and twelve years in the atmosphere, but during that short time it traps considerably more heat than an equivalent amount of carbon dioxide, which has a much longer lifespan in the atmosphere. In order to compare the relative impacts of different greenhouse gases, scientists devised the concept of global warming potential, which is a factor of how much heat is trapped in the atmosphere over a given time period by a particular gas, relative to carbon dioxide. Policymakers typically compare greenhouse gases over 20- and 100-year timeframes. The former gives greater weight to short-term damages, while the latter is more useful for longer-term planning (and has become the convention for most policymakers around the world). For methane from fossil sources, the global warming potentials for 20 and 100 years are 87 and 36, respectively. For more details, see: http://www.climatechange2013.org/images/report/WG1AR5_Ch08SM_FINAL.pdf.

3. http://www.eia.gov/dnav/ng/hist/n9050us2a.htm, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

4. The "break-even" leakage rate at which natural gas provides immediate and permanent climate benefits when burned instead of coal is roughly 3.2 percent. For using natural gas instead of gasoline, it is 1.6 percent, and for substituting natural gas for diesel, 1 percent. For more information, see: http://www.pnas.org/content/early/2012/04/02/1202407109.full.pdf+html and http://www.wri.org/publication/clearing-air.

5. For more information, see: http://www.onefuture.us/.

6. For studies that find higher estimates of methane leakage, see Brandt, A.R. et al. 2014. "Methane Leaks from North American Natural Gas Systems." Science Magazine. Vol 343, February 2014). Accessible at: <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>; Oliver Schneising et al. 2014. "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations" Earth's Future. Accessible at: <http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full>; Gabrielle Petron et al. 2014. "A New Look at Methane and Nonmethane Hydrocarbon Emissions From Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin." Journal of Geophysical Research: Atmospheres. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/pdf; and Scott Miller et al. 2013. "Anthropogenic Emissions of Methane in the United States," Proceedings of the National Academy of Sciences of the United States of America. Accessible at: <http://www.pnas.org/content/early/2013/11/20/1314392110.full.pdf+html. We should note as well that other studies have found leakage rates and emissions factors comparable to or less than the estimates in the EPA Greenhouse Gas Inventory. These include several bottom-up studies undertaken by EDF and universities. For those studies, see: http://www.edf.org/climate/methane-studies. For WRI's response to EDF and the University of Texas' production study, see: http://www.wri.org/blog/2013/09/new-study-sheds-light-methane-leakage-natural-gas.

7. For a discussion of these market barriers, see Chapter 4 of: http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states.

8. See http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201410&RIN=1004-AE14.

9. See http://www.epa.gov/airquality/oilandgas/pdfs/20150114fs.pdf.

10. While EPA is currently considering implementing methane emissions standards for some of the sources listed here, many states are taking action. See Box 1 for more information on potential EPA standards.

11. These emissions sources and recommendations are covered in more detail in the body of this working paper.

12. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf

13. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.

14. Analysis by the Clean Air Task Force found that semi-annual leak surveys at natural gas plants entailed negative net abatement costs, while quarterly surveys entailed small positive costs. See: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf. However, for some facilities, CATF recommends quarterly or monthly surveys. See: http://www.catf.us/resources/publications/files/WasteNot_Appendix.pdf. Frequency of leak surveys should also take into account the existence of regular maintenance practices that can help to identify and repair leaking equipment.

15. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted six scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions from nearly three million passenger vehicles. For this reason, this paper recommends the replacement of high-bleed pneumatic devices with no-bleed equivalents whenever feasible.

16. Wells without plunger lifts average 2.9 metric tons of methane emissions per year. (See: http://www.epa.gov/airquality/oilandgas/2014papers/attachmenti.pdf). Plunger lifts can eliminate up to 99 percent of methane emissions from liquids unloading when used properly and venting is minimized or eliminated.

17. For some small leaks, it is possible that emissions (and economic losses) from the blowdown associated with shutting down the equipment may be greater than emissions (and economic losses) from the leak itself. However, analysis from the Clean Air Task Force has found that "…[t]he evaluation of available survey data shows that most leaks, once identified, are economic to repair with a payback period less than one year. As a result, once the survey has been performed, it is economic to repair almost all the leaks." Source: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

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18. Includes the following emissions categories: non-associated gas wells, gas wells with hydraulic fracturing, heaters, separators, dehydrators, and meters/piping from the production stage; processing plants; compressor stations (transmission) stations, M&R (Trans. Co. Interconnect), M&R (Farm Taps + Direct Sales), Compressor Stations (Storage) Stations, Wells (Storage) from the transmission stage; and Meters/Regulator (City Gates) M&R>300, M&R 100-300, Reg >300, Reg 100-300 from the distribution stage.

19. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

20. ICF International. 2014. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." March 2014. Available at: http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

21. Massachusetts has such a program in place. For more information, see: http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/gas-meter-testing-and-replacement.html.

22. For more information on state-level natural gas production, see: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

23. http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.

24. ICF International, 2014.

25. Emissions measurement technology is still too expensive to require constant emissions monitoring from the millions of potential sources.

26. Because EPA does not report an average nationwide leakage rate, WRI calculated a figure of 1.2 percent using methane emissions data from the 2015 GHG Inventory, and natural gas production data from EIA. To convert volumes of methane to volumes of natural gas, we assumed natural gas to have an average methane content of 83 percent in the production stage, 87 percent during processing, and 94 percent during transmission, storage, and distribution. See U.S. Environmental Protection Agency (EPA). 2015. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013. April 2015. Accessible at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html and U.S. Energy Information Administration, "Natural Gas Gross Withdrawals and Production." Accessible at: <http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm> For studies that find higher estimates of methane leakage, see Brandt, A.R. et al. 2014. "Methane Leaks from North American Natural Gas Systems." Science Magazine. Vol 343, February 2014. Accessible at: <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>; Schneising, O. et al. 2014. "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations." Earth's Future. Accessible at: <http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full>; and Miller, S. et al. 2013. "Anthropogenic Emissions of Methane in the United States." Accessible at: <http://www.pnas.org/content/early/2013/11/20/1314392110.full.pdf+html>. We should note as well that other studies have found leakage rates and emissions factors comparable to or less than the estimates in the EPA Greenhouse Gas Inventory. These include several bottom-up studies undertaken by EDF and universities. For those studies, see http://www.edf.org/climate/methane-studies. For WRI's response to EDF and the University of Texas' production study, see: http://www.wri.org/blog/2013/09/new-study-sheds-light-methane-leakage-natural-gas.

27. See, for example: http://pubs.usgs.gov/of/2003/of03-409/of03-409.pdf.

28. In 2012, EPA finalized new air quality standards targeting VOCs and HAPs from sources located primarily at the well site. For more information, see http://www.epa.gov/airquality/oilandgas/actions.html. In January 2015, EPA announced its intention to propose new rulemakings that, in part, build on these VOC and HAP standards. For more information, see: http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

29. https://www.naesb.org/pdf2/wgq_bps100605w2.pdf.

30. For more information on how emissions reductions and economic benefits can go hand in hand, including a discussion of market barriers inhibiting wider deployment of emissions control technologies in the natural gas industry, see: http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states.

31. Self-reported emissions data from oil and gas companies suggest that even large, vertically integrated companies may not be utilizing best practices in their operations, despite being in the best position to do so. These companies can increase revenues by taking advantage of the technologies and practices described in this working paper to become more efficient and reduce their methane emissions. An October 2014 study by ClimateWire, which looked at emissions data reported to EPA under the Greenhouse Gas Reporting Program, found that "[t]he worst offenders have little in common when it comes to the scale or nature of operations. The implication is that companies do not all tackle the methane problem with equal seriousness, especially in the absence of comprehensive regulation." For more information, see: http://www.eenews.net/climatewire/2014/10/06/stories/1060006912 and http://www.epa.gov/ghgreporting/.

32. Source: ICF International, 2014. Moreover, a November 2013 study found that an accelerated pipeline replacement program in just five states could generate nearly 50,000 jobs. For more details, see: http://www.e3network.org/papers/The-Keystone-Pipeline-Debate.pdf. Accelerated pipeline replacement programs are discussed in more detail in the Distribution section of this working paper.

33. According to a September 2014 study from Stratus Consulting, methane emissions from oil and gas development on public lands increased by 135 percent between 2008 and 2013, to 175,000 metric tons of methane. For more information, see: http://wilderness.org/sites/default/files/Stratus-Report.pdf and http://cdn.americanprogress.org/wp-content/uploads/2014/10/ReducingMethane.pdf.

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34. There are many market barriers inhibiting greater uptake of cost-effective measures by the natural gas industry. These include principal-agent problems, whereby incentives for investing in emissions-control technologies are not well aligned; imperfect information on the scope of the emissions problem; and opportunity costs. For more details, see Chapter 4 of Bianco et al. October 2014. "Seeing is Believing: Creating a New Climate Economy in the United States." Washington, D.C.: World Resources Institute. Available at: http://www.wri.org/sites/default/files/seeingisbelieving_working_paper.pdf.

35. The "break-even" leakage rate at which natural gas becomes cleaner than coal over all time horizons is roughly 3.2 percent. For gasoline, it is 1.6 percent, and for diesel, 1 percent. For more information, see: http://www.pnas.org/content/early/2012/04/02/1202407109.full.pdf+html and http://www.wri.org/publication/clearing-air.

36. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentl.pdf.

37. http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

38. Section 111 grants EPA authority to set standards of performance for harmful air emissions, including greenhouse gases, from new and existing stationary sources. Once EPA sets a minimum standard of performance, states are required to implement and enforce compliance with that standard. This is the same section of the Clean Air Act that EPA is using to set carbon dioxide emissions standards for new and existing power plants. For the full text of Section 111, see: http://www.law.cornell.edu/uscode/text/42/7411.

39. http://www.epa.gov/airquality/oilandgas/whitepapers.html.

40. For more details on the administration's January 2015 announcement that it will propose methane standards for new and modified natural gas infrastructure, see: http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

41. This is especially true when the health benefits of avoided emissions of VOCs and other hazardous air pollutants are included. Note that it might be necessary to restructure service provider contracts to ensure that the economic benefits of reducing leaks of natural gas accrue to the company investing in the equipment or personnel.

42. There are examples of this phenomenon in the area of regulating methane emissions, as well. EPA's 2012 New Source Performance Standard requiring the use of reduced emissions completions at the wellhead was modeled on a similar, successful approach used in Colorado and Wyoming. See: http://www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf and http://www.epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=bc4a4812-ca46-4d22-b593-e3929c2c64a6.

43. Ibid.

44. For President Obama's methane strategy, see: http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf. For more information on Section 111 of the Clean Air Act, see http://www.law.cornell.edu/uscode/text/42/7411 and http://web.law.columbia.edu/climate-change/clean-air-act.

45. Completions of oil wells with associated natural gas are not covered by the 2012 NSPS, despite being a major source of natural gas production and a significant source of VOC and methane emissions. EPA should close this loophole to ensure that all natural gas production is subject to the same emission reduction requirements.

46. For a sample permit application describing green completion requirements in Wyoming, see: http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Application%20Forms/AQD-OG11_Green%20Completion%20Application.pdf.

47. http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf.

48. For more details on the technologies listed in this paper, as well as some of the methods currently available to reduce emissions from these sources, see: http://www.epa.gov/gasstar/tools/recommended.html.

49. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

50. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

51. EPA's annual Greenhouse Gas Inventory is still considered the most definitive source of emissions estimates, though many recent studies contend that the Agency significantly underestimates the amount of methane emitted by the natural gas industry. Part of the reason for the discrepancy is the way in which EPA calculates its estimates. Because measuring emissions from the millions of sources in the natural gas supply chain is infeasible, EPA multiplies the number of processes or pieces of equipment (activity data) by an average emissions factor for that process or equipment. Both of these inputs are estimates, but there is more certainty around the activity data than the emissions factors. Emissions factors are averages, and may underestimate the impact of "superemitters," that is, a small fraction of sources responsible for a large fraction of emissions. Moreover, emissions factors can vary widely across different geographies, and across companies. To the extent possible, states should supplement EPA Inventory data with direct measurements to provide a more robust picture of methane emissions from various sources in each state. For examples of recent studies suggesting higher amounts of methane emissions, see: http://www.pnas.org/content/110/50/20018.full and http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract.

52. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Includes estimated reductions due to voluntary measures.

53. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf and http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

54. For reference, the average Henry Hub daily spot price over 2014 was approximately $4.37 per Mcf, though the average price through the first five months of 2015 was just $2.83 per Mcf. See: http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm.

55. http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.

56. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Assumes voluntary measures result in emissions reductions of 45 percent, the average for emissions sources in the production sector, according to the EPA Inventory.

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57. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf. As of this writing, there are additional studies underway that aim to improve measurement estimates of emissions from pneumatic devices and understand the sources of variability within those estimates.

58. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted 6 scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions from nearly three million passenger vehicles. And Allen et al. (2013) found that even low-bleed devices often emit more than six scf per hour (see: http://www.pnas.org/content/110/44/17768.full). For these reasons, this paper recommends the replacement of high-bleed, low-bleed, and intermittent pneumatic devices with no-bleed equivalents whenever feasible, and including all low-bleed pneumatics in LDAR programs.

59. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf, and http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

60. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

61. http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

62. 2 Colo. Code Regs. § 404-1:805(b)(2)(E); 5 Colo. Code Regs. § 1001-9 XVIII.C.1.

63. Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, Section XVIII. Available at: https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=5670. Other rules in Colorado, adopted in February 2014, address methane emissions from additional sources.

64. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

65. http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf, http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html, http://pubs.acs.org/doi/abs/10.1021/es504016r.

66. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

67. http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.

68. Until recently, liquids unloadings were the most significant source of methane emissions from natural gas development in EPA's annual greenhouse gas inventory. However, in its 2013 Greenhouse Gas Inventory, in response to a survey from the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA), EPA reduced the emission factor used to estimate emissions from liquids unloading by over 90 percent. See: http://insideepa.com/201302262425851/EPA-Daily-News/Daily-News/citing-industry-data-epa-cuts-ghg-estimates-for-natural-gas-sector/menu-id-1046.html and http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.

69. For some of these options, see: http://www.epa.gov/gasstar/documents/ll_options.pdf.

70. There is debate surrounding the effectiveness of plunger lifts as a low-emissions alternative to well blowdowns. A 2012 industry survey found that wells using plunger lifts for liquids unloading were responsible for more emissions than those that did not use plunger lifts. However, this could be due to particularities in the geology at the wells that did use plunger lifts, or to ineffective use of the equipment by untrained workers. See: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf and http://www.epa.gov/airquality/oilandgas/2014papers/attachmenth.pdf.

71. http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.

72. http://www.epa.gov/airquality/oilandgas/2014papers/20140415liquids.pdf.

73. Ibid.

74. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf,

75. http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

76. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

77. http://www.epa.gov/airquality/oilandgas/2014papers/attachmento.pdf, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_BB_EDF.xlsx, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_CC_EDF.xlsx, http://www.epa.gov/airquality/oilandgas/2014papers/attachmentk.pdf.

78. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentl.pdf.

79. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

80. See, for example: http://www.epa.gov/airquality/oilandgas/2014papers/attachmento.pdf and http://www.epa.gov/airquality/oilandgas/2014papers/attachmentp.pdf.

81. http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

82. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

83. http://arpa-e.energy.gov/?q=arpa-e-news-item/arpa-e-announces-60-million-disruptive-technologies-cut-emissions-boost-energy, http://www.edf.org/energy/natural-gas-policy/methane-detectors-challenge.

84. Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, Section XVII F. Available at: https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.

85. Noble Energy, Encana, and Anadarko Petroleum worked with Colorado officials to help craft the rules, and publicly support the state's efforts. See: http://www.bizjournals.com/denver/blog/earth_to_power/2014/02/noble-energy-anadarko-petroleum-and.html?page=all.

86. Ibid.

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87. There are trade-offs involved when deciding how quickly leaks must be repaired after they are first detected. For example, a shorter lead time likely means more employees need to be trained in how to repair leaks. Nevertheless, because learning how to fix most leaks does not require extensive training, and LDAR is generally one of the most cost-effective measures for reducing emissions, we believe that five days should be the upper bound for the deadline before which detected leaks must be repaired, with exceptions for extenuating circumstances such as those identified by Colorado.

88. Personal communication with William C. Allison V, Director, Air Pollution Control Division, Colorado Department of Public Health and Environment, 9/23/14. Wyoming requires the use of infrared cameras at processing plants and new wells.

89. Pennsylvania requires the use of LDAR at new wells within 60 days of entering into production, and annually thereafter. At compressor stations and processing plants, Pennsylvania requires an initial LDAR survey, and quarterly surveys thereafter. For more information, see: http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf and http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/MethaneRegulations.pdf.

90. Ohio's new rules require companies to develop plans for regular LDAR, to be submitted along with applications for permits-to-install. Covered equipment includes pumps, compressors, pressure relief devices, valves, flanges, and storage containers. Monitoring must occur quarterly for the first year of operation, and repairs must be made within five days of discovery. After the first year, if less than two percent of equipment is found to be leaking, operators can reduce their monitoring to semi-annually and then annually. For more information, see: http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf. For information on permit applications, see http://www.epa.ohio.gov/dapc/genpermit/genpermits.aspx.

91. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

92. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.

93. Analysis by the Clean Air Task Force found that semi-annual leak surveys at natural gas plants entailed negative net abatement costs, while quarterly surveys entailed small positive costs. See: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf. However, for some facilities, CATF recommends quarterly or monthly surveys. See: http://www.catf.us/resources/publications/files/WasteNot_Appendix.pdf. Frequency of leak surveys should also take into account the existence of regular maintenance practices that can help to identify and repair leaking equipment.

94. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted six scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions of nearly three million passenger vehicles. For this reason, this paper recommends the replacement of high-bleed and low-bleed pneumatic devices with no-bleed equivalents whenever feasible.

95. Wells without plunger lifts average 2.9 metric tons of methane emissions per year. (See: http://www.epa.gov/airquality/oilandgas/2014papers/attachmenti.pdf). Plunger lifts can eliminate up to 99 percent of methane emissions from liquids unloading when used properly and venting is minimized or eliminated.

96. For some small leaks, it is possible that emissions (and economic losses) from the blowdown associated with shutting down the equipment may be greater than emissions (and economic losses) from the leak itself. However, analysis from the Clean Air Task Force has found that "…[t]he evaluation of available survey data shows that most leaks, once identified, are economic to repair with a payback period less than one year. As a result, once the survey has been performed, it is economic to repair almost all the leaks." Source: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

97. Includes the following emissions categories: non-associated gas wells, gas wells with hydraulic fracturing, heaters, separators, dehydrators, and meters/piping from the production stage; processing plants; compressor stations (transmission) stations, M&R (Trans. Co. Interconnect), M&R (Farm Taps + Direct Sales), Compressor Stations (Storage) Stations, Wells (Storage) from the transmission stage; and Meters/Regulator (City Gates) M&R>300, M&R 100-300, Reg>300, Reg 100-300 from the distribution stage.

98. For more information on the composition of natural gas, see: Burruss, R.C. and R.T. Ryder, "Composition of Crude Oil and Natural Gas Produced from 14 Wells in the Lower Silurian 'Clinton' Sandstone and Medina Group, Northeastern Ohio and Northwestern Pennsylvania." March 22, 2004. Washington, D.C.: U.S. Department of Interior, U.S. Geological Survey. Available at: http://pubs.usgs.gov/of/2003/of03-409/of03-409.pdf; and North American Energy Standards Board, "Natural Gas Specs Sheet." June 2004. Available at: https://www.naesb.org//pdf2/wgq_bps100605w2.pdf.

99. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

100. Ibid.

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101. http://www.epa.gov/gasstar/documents/ll_wetseals.pdf. Up-front costs for dry seals might be greater than those for wet seals, however.

102. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

103. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

104. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentr.pdf, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_AA_EDF.xlsx.

105. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

106. http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.

107. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf, http://www.epa.gov/gasstar/documents/CaptureMethanefromCentrifugalCompressionSealOilDegassing.pdf.

108. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

109. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Note: A similar amount of methane was leaked or vented from engines in the production and transmission stages as well.

110. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

111. http://www.epa.gov/ttnchie1/ap42/ch03/final/c03s02.pdf.

112. http://epa.gov/gasstar/documents/replacegas.pdf.

113. http://epa.gov/gasstar/documents/installelectricstarters.pdf.

114. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

115. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

116. ICF International. 2014. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." Available at: http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

117. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

118. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf.

119. Ibid.

120. Ibid, http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

121. See, for example: http://sites.biology.duke.edu/jackson/ep2013.pdf and http://sites.biology.duke.edu/jackson/est2014.pdf.

122. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

123. See, for example: http://www.puco.ohio.gov/puco/index.cfm/consumer-information/consumer-topics/natural-gas-pipeline-safety-in-ohio/#sthash.sLdAB0Xj.dpbs. For this reason, many emissions abatement measures in the distribution segment are much less cost-effective than measures in other segments of the natural gas value chain. The exception is equipment leaks at above-ground meters and regulation stations, which should be subject to the same LDAR regimes as processing plants, compressor stations, and other upstream infrastructure discussed above. For more information, see: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

124. For example, Connecticut, New York, and Pennsylvania—three of the states with the most miles of cast iron pipelines—have set goals for complete replacement with plastic or coated steel by 2080, 2090, and 2111, respectively. For more information, see: https://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/.

125. See, for example: http://www.wbur.org/2014/07/07/patrick-springfield-gas-leaks.

126. For full text of bill, see: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1371.

127. Ibid.

128. Massachusetts has such a program in place. For more information, see: http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/gas-meter-testing-and-replacement.html.

129. One such company, Picarro Inc., has invented vehicle-mounted leak survey technology that has been used by researchers in Boston and Washington, D.C. to identify the location and magnitude of leaks from distribution pipelines—many of which were unknown to the local utility. For more information on the Picarro Surveyor, see: http://www.picarrosurveyor.com/. For studies, see http://sites.biology.duke.edu/jackson/ep2013.pdf and http://sites.biology.duke.edu/jackson/est2014.pdf.

130. Personal communication with Greg Davies, December 7, 2014.

131. Source: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm. Note: other states have policies in place that will reduce methane emissions, but only Colorado has rules that address methane directly.

132. See, for example: https://www.sustainableshale.org/.

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ABOUT WRI

World Resources Institute is a global research organization that turns big ideas into action at the nexus of environment, economic opportunity and human well-being.

Our Challenge
Natural resources are at the foundation of economic opportunity and human well-being. But today, we are depleting Earth's resources at rates that are not sustainable, endangering economies and people's lives. People depend on clean water, fertile land, healthy forests, and a stable climate. Livable cities and clean energy are essential for a sustainable planet. We must address these urgent, global challenges this decade.

Our Vision
We envision an equitable and prosperous planet driven by the wise management of natural resources. We aspire to create a world where the actions of government, business, and communities combine to eliminate poverty and sustain the natural environment for all people.

Our Approach
COUNT IT
We start with data. We conduct independent research and draw on the latest technology to develop new insights and recommendations. Our rigorous analysis identifies risks, unveils opportunities, and informs smart strategies. We focus our efforts on influential and emerging economies where the future of sustainability will be determined.

CHANGE IT
We use our research to influence government policies, business strategies, and civil society action. We test projects with communities, companies, and government agencies to build a strong evidence base. Then, we work with partners to deliver change on the ground that alleviates poverty and strengthens society. We hold ourselves accountable to ensure our outcomes will be bold and enduring.

SCALE IT
We don't think small. Once tested, we work with partners to adopt and expand our efforts regionally and globally. We engage with decision-makers to carry out our ideas and elevate our impact. We measure success through government and business actions that improve people's lives and sustain a healthy environment.

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