# Regulation of Methane Emissions from Unconventional Oil and Gas: Current Approaches and Possibilities for Innovation Based on Emerging Science

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## Table of Contents

# Executive Summary

The Penn State Center for Energy Law and Policy has led an interdisciplinary, multi-stakeholder pilot project since Spring 2017 focused on regulatory approaches to methane and other air emissions from unconventional oil and gas operations. This project has included extensive research by an interdisciplinary Penn State team, two conferences with a mix of stakeholders, engagement with individual and groups of stakeholders, and creation of smaller working groups to follow up on specific topics. These processes have brought together leaders from industry, government, and the environmental community with Penn State researchers. The team produced a draft White Paper in November 2017 in advance of the first conference. This final White Paper reflects the learning from the November 2017 and May 2018 conferences; specific feedback from industry, government, and environmental community participants; new regulatory developments; and additional research. This White Paper emerges from the interdisciplinary research work of Penn State faculty experts in a collaborative process with diverse stakeholders to explore how emerging science and technology can be used more effectively in the regulatory process; it does not represent the official position of the University.

Federal and state regulations have aimed at reducing methane emissions from various sectors because it is a potent greenhouse gas. As discussed in depth in Section II, methane comes from many sources; unconventional oil and gas produces only a fraction of global methane emissions. However, this pilot project focused on methane emissions from unconventional oil and gas in particular because of a pending (now finalized) revision to the permitting process in Pennsylvania. Regulation often struggles to incorporate fast-moving science and technology; this project combined interdisciplinary research from scientific, economic, and legal perspectives on methane emissions from unconventional oil and gas to address this concern and inform regulatory approaches. Substantial research exists on methane emissions from unconventional oil and gas, but major data gaps remain; the White Paper recommends areas where further research is needed. In addition, we have formed working groups focused on science and technology, economics, and regulation to address questions raised during this process and these data gaps.

A review of available data from Pennsylvania suggests that methane emissions stem from multiple sources, including agriculture, coal mining, and conventional and unconventional oil and gas production. Unconventional gas basins in Pennsylvania appear to have the lowest methane emissions rate as a function of production of any natural gas production area in the United States, with approximately 0.2 to 0.8 percent of production being lost to atmospheric emissions in production and gathering activities. Quantifying the contribution of oil and gas production (or any other source) to overall methane emissions in Pennsylvania is complicated by limited measurements, an important data gap that additional research could address.

This additional data collection is important because of the divergence between emissions inventories maintained by the Pennsylvania Department of Environmental Protection and studies of atmospheric measurements. These inventories suggest an emissions rate from unconventional oil and gas activities substantially lower than the rate estimated by atmospheric measurements. Researchers have hypothesized that large leaks associated with abnormal operating conditions and not captured in the inventories may be responsible for the discrepancy between atmospheric and inventory emissions estimates. However, the Commonwealth does not have the data collection necessary to detect or quantify changes in methane emissions over time. More research is needed to test this hypothesis, and to evaluate the cause of the discrepancy between atmospheric and inventory results. One of the working groups is focused on these science and technology and measurement questions.

Regulation of methane emissions at the federal level is in flux and state approaches vary widely and continue to evolve. Proposed methane rules under the Obama Administration by the U.S. Environmental Protection Agency and the U.S. Bureau of Land Management are under review by the Trump Administration. Lack of regulatory closure at the federal level has left the states taking the lead on regulating emissions. Many states with active unconventional oil and gas sectors are adopting regulatory approaches, but such approaches are not consistent across states. Although both federal and existing state regulations ground their requirements in the best available technology, regulations vary in their regulatory mechanisms, details, and level of prescriptiveness (i.e., the extent to which they mandate that operators reduce emissions in particular ways versus allow operators to develop a plan for meeting set emissions goals). Pennsylvania is one of the more prescriptive states, although its final revised 2018 general permits are less prescriptive than the initial proposals after it responded to stakeholder feedback. Of the six states studied, California is the only one that maintains a state-wide network of methane sensors. Given conflicting assessments of methane emissions and lack of continuous monitoring, the White Paper recommends further exploration of how additional emissions data collection could be used to improve regulation.

The emergence of new voluntary industry measures to reduce emissions further complicates analysis of how regulation can be most effective in reducing emissions. For example, over forty operators nationwide have signed on to the Environmental Partnership program sponsored by the American Petroleum Institute that was launched in December 2017; there are other voluntary efforts as well. Such collaborative efforts occur against a backdrop of voluntary efforts by individual companies. At the stakeholder conferences held as part of this pilot project, there was broad support for the value of reducing methane emissions. Industry participants indicated they were strongly motivated to minimize emissions to avoid economic waste and reported taking a number of measures to monitor for methane leaks and make appropriate repairs. Ideally, voluntary and regulatory efforts are complementary and together achieve emissions-reduction goals. Moreover, data is needed on the effect of voluntary efforts as they develop; for instance, the Environmental Partnership is so new that its impacts on overall emissions cannot yet be quantified. One of the working groups is examining different regulatory approaches, including how they interact with voluntary measures and how they might use proposed emissions data collection.

Multiple technology options exist for reducing methane emissions from Pennsylvania's unconventional oil and gas sector. Evaluating the costs and abatement potential for Pennsylvania specifically is challenging because little state-specific data exists on costs and adoption for specific technologies. Additionally, the technology environment for detection and mitigation is constantly changing and a mechanism is needed to update our best estimates of methane abatement economics on a continuous basis. Based on the limited economic data that exists, we estimate that at current market prices for natural gas, operators have internal incentives to adopt technologies and practices that would reduce emissions by between 35 and 60 percent, depending on whether inventories or point-based measurement studies are used to determine emissions abatement potential for production and gathering activities. Social costs of methane emissions vary widely, but based on total social costs (not just those borne internally by operators), nearly all methane emissions abatement across the natural gas value chain would pass a cost-benefit test regardless of whether inventory emissions or point-based measurement studies are used. Our analysis also suggests many abatement technologies could be adopted at costs per unit of natural gas output that are less than 5 percent of current market prices in the Appalachian region. However, this is another area with significant data gaps, and additional data and analysis are needed. Another working group is focusing on these issues.

Our research efforts, conferences, stakeholder dialogues, and initial meetings by some of the working groups suggest the longer-term need for industry, government, and NGO stakeholders to partner with the research community to advance knowledge of the science, economics, and regulation in ways that might assist future regulatory design. First, since methane is a powerful greenhouse gas, a more comprehensive strategy across multiple sectors and sources is warranted at the state level. Moreover, in the absence of comprehensive federal regulation, greater coordination among states is needed, particularly where regional resources span more than one state. Achieving an appropriate coordinated response, however, requires more comprehensive measurements to detect long-term trends as well as emissions anomalies in a particular area that might warrant special attention. Second, regulatory design needs better and more current information on emissions measurement technology, the technical potential for emissions abatement, and the costs of achieving various abatement levels. More precise understanding of the sources of methane emissions across the value chain and how to most cost-effectively address them would enable the design of more efficient and effective regulatory mechanisms. We hope to begin to make progress on these questions in the working groups and further research that emerges from them in collaboration with our research team.

# I. Introduction

As part of Penn State's major strategic commitment to serve the Commonwealth, nation, and world through cutting-edge interdisciplinary research and partnerships in energy, the new Penn State Center for Energy Law and Policy aims to provide an innovative national model for how a major public research university can contribute to energy law and policy dialogues. Deans representing all of Penn State's disciplines – as well as many Chancellors and other academic leaders – have agreed to collaborate on this Center, which allows it to draw from a breadth of energy research not generally brought together with law and policy. No other energy research center in the United States is fully utilizing the strengths of a leading land-grant research university in this way, providing Penn State with a unique opportunity to have a major impact on the development of knowledge and public policy.

The Center for Energy Law and Policy provides a hub for systematic interdisciplinary energy law and policy research. Its approach is broadly collaborative, bringing together the many strands of law and policy relevant energy research at Penn State to (1) explore how independent, interdisciplinary energy research at Penn State might be used to inform regulatory approaches and (2) convene stakeholders from industry, government, nongovernmental organizations, and communities to discuss the implications of this research.

As proof of concept for this approach, the Center for Energy Law and Policy developed an initial pilot project on regulatory approaches to methane and other air emissions from unconventional oil and gas operations to explore how Penn State can contribute to public policy by producing research and convening key stakeholders on a pressing issue. Experts in atmospheric science, energy economics, and law are working together to explore the potential ways in which Penn State's cutting-edge scientific research can contribute to how this type of technology-based regulation is approached. We have discussed these ideas with leaders in business, government, and the environmental community through a number of one-on-one conversations with individual stakeholders from industry, government and nongovernmental organizations; conferences with stakeholder participants held in November 2017 and May 2018; a public discussion session summarizing the findings of this effort during Penn State's annual Energy Days event in May 2018; and resulting working groups that began to meet in August 2018.

This White Paper was first circulated as a draft in November 2017 and has been revised based on stakeholder comments, discussion at the conferences, regulatory developments, and additional research over the last several months. This document is the first work product of this interdisciplinary pilot project team and represents an effort to open a dialogue about how emerging science and technology could be used more effectively in regulation of methane and other air emissions in this context, as well as more broadly. The difficulty of effectively incorporating ever-changing science and technology is a crucial challenge for regulation, and one that a major research university like Penn State is well-situated to help address.

This White Paper assumes that regulation of methane and other air emissions of unconventional oil and gas has two core goals:

(1) *emissions reduction* (either by minimizing or keeping below designated thresholds), and

(2) *cost effectiveness* (under either approach, efficient reductions that achieve the goal in a way that minimizes administrative and implementation costs).

This White Paper's focus is on how emerging science and technology can help achieve those goals and how regulatory processes and approaches can be designed to incorporate evolving technology. In developing our analysis, we have drawn from relevant scientific, economic, and legal research, which we reference throughout the White Paper. We also have incorporated emerging scientific research by members of this team as an example of the kinds of science and technology developments that could inform regulatory approaches.

# II. Scientific Understanding of Methane Emissions from Unconventional Oil and Gas Operations and Emerging Monitoring Approaches

This Section provides background context on why methane emissions matter and the complexity of monitoring and regulating them in the context of unconventional oil and gas. It begins by situating methane emissions from unconventional oil and gas in the broader context of methane emissions from all sources and explaining methods of quantification of current methane emissions. It then describes primary sources of U.S. and Pennsylvania methane emissions and methane emissions in the broader context of statewide greenhouse gas emissions. Finally, it turns to the impacts associated with methane emissions and makes recommendations for future studies.

## *A. Global Sources of Methane Emissions*

Methane is emitted by a wide variety of processes. The processes that result in methane emissions fall into two major categories: (1) current biological processes (biogenic), and (2) fossil reservoir processes (thermogenic). Major biological sources include landfills and wastewater treatment, natural wetlands, animal agriculture, biomass burning, and wetland agriculture (mainly rice). Major thermogenic sources are emissions from coal mines, the oil and natural gas industries, and natural seepage from geologic reservoirs. Each of these sources is significant globally; both biogenic and thermogenic emissions include natural and anthropogenic (human-based) processes.[1] This White Paper, as well as federal and state regulation of methane emissions, focuses on anthropogenic emissions – those caused by human activity – since laws and regulations can influence human behavior resulting in emissions.

Many methane emissions result from a multitude of small sources distributed over large areas and no routine system of accounting exists for these sources; uncertainties in the emission rates for these sources are large.[2] The amount of methane in the global atmosphere, however, is very well known from direct atmospheric measurements.[3] These global atmospheric data, together with knowledge of the global rate of methane oxidation,[4] yield a fairly good understanding of total global methane emissions. Changes in total global methane emissions are thus detectable but

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[1] Philippe Ciais et al., *Carbon and Other Biogeochemical Cycles*, *in* CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS 465 (Thomas F. Stocker et al. eds., 2013).

[2] *Id.*

[3] *Id.*; Edward J. Dlugokencky et al., *Atmospheric Methane Levels Off: Temporary Pause or a New Steady State*, 30 GEOPHYSICAL RESEARCH LETTERS 19 (2003), doi: 10.1029/2003GL018126; NOAA EARTH SYSTEMS RESEARCH LABORATORY, https://www.esrl.noaa.gov/gmd/ (last visited Sept. 3, 2018).

[4] Ciais, et al., *supra* note 1; Dlugokencky et al., *supra* note 3.

understanding the causes of these changes is challenging.[5] Human activity now accounts for approximately 50 to 60 percent of total global emissions; the atmospheric concentration of methane is now approximately 2.5 times higher than during preindustrial times (prior to 1800). Concentrations were one fourth of present concentrations during the last ice age and were within the overall range of two fifths to one fourth of present concentrations for at least the last 800,000 years, the limit of the ice-core record of atmospheric gas concentrations.[6]

### B. *Methods of Quantification of Current Methane Emissions*

Conflicting assessments exist concerning current rates of methane emissions from the Commonwealth of Pennsylvania. No continuous measurement of these emissions exists. This section discusses the methodology behind current assessments and their strengths and weaknesses in order to aid interpretation of the differing emissions estimates that are presented. This situation and these methods are not unique to Pennsylvania.

#### 1. Inventory Assessments

Regional estimation and reporting of methane emissions is typically done using inventory assessments.[7] In an inventory assessment, activities associated with methane emissions are accounted for, summed over a region, and combined with emissions factors that estimate emissions per unit of activity to provide an estimate of total emissions. These "bottom up" methods provide detailed spatial data concerning the locations of emissions and a direct connection between emissions and their causes. This understanding is necessary for mitigation and an important strength of this approach to estimation.

However, inventory assessments also face limitations because the emission factors are typically based on short-term measurements of a very small fraction of the emitting infrastructure and extrapolated a great deal over space and time. Furthermore, inventories by definition encompass known sources. Both the extrapolation involved and the potential for missing sources create the potential for systematic error in inventory-based estimates of emissions.

#### 2. Atmospheric Measurements

Atmospheric measurements provide a complementary approach to inventory assessments.[8] Enhancements in atmospheric methane concentration can be detected downwind of source

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[5] Euan G. Nisbet, Edward J. Dlugokencky & Philippe Bousquet, *Methane on the Rise Again*, 343 SCI. 493 (2014), doi: 10.1126/science.1247828; R. Subramanian et al., *Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, 49 (5) ENVTL. SCI. TECH. 3252 (2015), doi: 10.1021/es5060258.

[6] Ciais, et al., *supra* note 1.

[7] ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSION AND SINKS: 1990-2013, ANNEX 3.6 (2015), *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015.

[8] Stephen M. Ogle et al., *An Approach for Verifying Biogenic Greenhouse Gas Emissions Inventories with Atmospheric $CO_2$ Concentration Data*, 10 034012 ENVRTL. RES. LETTERS (2015), doi:10.1088/1748-9326/10/3/034012.

regions with carefully calibrated instruments deployed on stationary[9] (e.g., towers) or mobile[10] (e.g., aircraft, automobiles) platforms. These atmospheric methane enhancements can be converted into emissions estimates,[11] given knowledge of atmospheric transport and dispersion based on a combination of observations and numerical models of atmospheric flow. These methods can be divided into two categories: plume dispersion estimates and regional atmospheric budget estimates.

Plume dispersion methods estimate emissions[12] by measuring atmospheric enhancements typically tens to hundreds of meters downwind of a single source, a distance where atmospheric turbulence is still mixing these gases within the lowest layer of the atmosphere, the atmospheric boundary layer. The most common approach to converting plume enhancement measurements into emissions estimates is the Gaussian plume model,[13] the basis of the standard method of the U.S. Environmental Protection Agency (EPA) for point-source emissions estimation.[14] This method can measure emissions from an entire well site or compressor station. These emissions estimates can be compared to inventory assessments with a good understanding of the specific pieces of infrastructure being tested, creating a site-level "top-down" and "bottom-up" methodological comparison which can then be compared to check for potential errors in the emission factors. With either plume dispersion or inventory methods, it is difficult to measure emissions from a large fraction of emission sites or over a long period of time. A great deal of extrapolation over time and space is still required to estimate statewide emissions.

Regional atmospheric budgets use observed atmospheric enhancements measured many kilometers downwind of a source region, after emissions have been mixed through the depth of the atmospheric boundary layer. Atmospheric enhancements can be converted into emissions estimates using methods ranging from simple mass balance calculations[15] to more

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[9] Natasha L. Miles et al., *Quantification of Urban Atmospheric Boundary Layer Greenhouse Gas Dry Mole Fraction Enhancements: Results from the Indianapolis Flux Experiment (INFLUX)*, 5 ELEMENTA SCI. ANTHROPOCENE. Article 27 (2017), doi: http://doi.org/10.1525/elementa.127; Natasha L. Miles et al., *Calibration and Field Testing of Cavity Ring-Down Laser Spectrometers Measuring $CH_4$, $CO_2$, and $\delta^{13}CH_4$ Deployed on Towers in the Marcellus Shale Region*, 11 ATMOSPHERIC MEASUREMENT TECH. 1273 (2018), https://doi.org/10.5194/amt-11-1273-2018.

[10] Anna Karion et al., *Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region*, 49 (13) ENVTL. SCI. TECH. 8124 (2015), doi: 10.1021/acs.est.5b00217; Zachary R. Barkley et al., *Quantifying Methane Emissions from Natural Gas Production in Northeastern Pennsylvania,* 17 ATMOSPHERIC. CHEMISTRY & PHYSICS. 13941 (2017), https://doi.org/10.5194/acp-17-13941-2017; Mark Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin*, 50 ENVTL. SCI. TECH. 2099 (2016), 10.1021/acs.est.5b05503; Chris W. Rella et al., *Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique*, 49 ENVTL. SCI. TECH. 4742 (2015),doi: 10.1021/acs.est.5b00099.

[11] *See supra* sources cited in note 10; Thomas Lauvaux et al., *High-Resolution Atmospheric Inversion of Urban $CO_2$ Emissions During the Dormant Season of the Indianapolis Flux Experiment (INFLUX),* 121 J. GEOPHYSICAL. RES.: ATMOSPHERES. 5213 (2016), doi:10.1002/2015JD024473*;* Seongeun Jeong et al., *A Multitower Measurement Network Estimate of California's Methane Emissions*, 118 J. GEOPHYSICAL. RES.: ATMOSPHERES. 11,339 (2013), doi:10.1002/jgrd.50854.

[12] Omara et al., *supra* note 10; Rella et al., *supra* note 10.

[13] HANS A. PANOFSKY & JOHN A. DUTTON, ATMOSPHERIC TURBULENCE: MODELS AND METHODS FOR ENGINEERING APPLICATIONS (1984).

[14] EBEN THOMA & B. SQUIER, OTM 33 GEOSPATIAL MEASUREMENT OF AIR POLLUTION, REMOTE EMISSIONS QUANTIFICATION (GMAP-REQ) AND OTM33A GEOSPATIAL MEASUREMENT OF AIR POLLUTION-REMOTE EMISSIONS QUANTIFICATION-DIRECT ASSESSMENT (GMAP-REQ-DA) (2014).

[15] Karion et al., *supra* note 10.

mathematically complex data assimilation approaches.[16] Regional budgets can measure the aggregated emissions from an entire shale gas basin or city. Aircraft-, satellite- and tower-based measurements can all encompass large regions[17] and, if maintained, can be used to monitor emissions for months to years.[18] All emissions are quantified, regardless of whether they are accounted for in inventories.

The primary disadvantage of these methods is their limited ability to easily attribute the calculated emissions to individual sources. Careful quantification of background concentrations and atmospheric transport are also required. Finally, the availability of high-quality atmospheric methane concentration data is limited.[19]

Aircraft observations have been applied multiple times in recent years to try to address these challenges and quantify emissions from the unconventional oil and gas industry in the United States.[20] Emissions can be monitored over time with longer-term atmospheric observations. Tower-based data have been used to quantify emissions from urban areas,[21] a shale-gas basin,[22] and at state[23] to continental scales.[24] Satellite-based methane observations are becoming available and show promise for identifying and quantifying continental[25] and basin-scale[26] methane emissions. Trace gases such as ethane[27] and stable isotopes of methane[28] can be used

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[16] Lauvaux et al., *supra* note 11.

[17] Karion et al., *supra* note 10; Barkley et al, *supra* note 10.

[18] Scot M. Miller et al., *Anthropogenic Emissions of Methane in the United States*, 110 PROC. NAT'L. ACAD. SCI. 20,018 (2013), doi:10.1073/pnas.1314392110; Alexander J. Turner et al., *A Large Increase in U.S. Methane Emissions over the Past Decade Inferred from Satellite Data and Surface Observations*, 43 GEOPHYSICAL. RES. LETTERS. 2218 (2016), doi:10.1002/2016GL067987; Lori M. Bruhwiler et al., *Carbon Tracker-$CH_4$: An Assimilation System for Estimating Emissions of Atmospheric Methane,* 14 ATMOSPHERIC. CHEMISTRY & PHYSICS. 8269 (2014), doi: 10.5194/acp-14-8269-2014; Lauvaux et al., *supra* note 11.

[19] *See* ESRL Global Monitoring Division, NATIONAL OCEANIC &ATMOSPHERIC ADMINISTRATION, https://www.esrl.noaa.gov/gmd/about/aboutgmd.html (last visited July 29, 2018); GREENHOUSE GASES OBSERVING SATELLITE (GOSAT), http://www.gosat.nies.go.jp/en/ (last visited July 29, 2018).

[20] Barkley et al., *supra* note 10; Karion et al., *supra* note 10; Anna Karion et al., *Methane Emissions Estimate from Airborne Measurements over A Western United States Natural Gas Field*, 40 GEOPHYSICAL RES. LETTERS 4393 (2013), doi: 10.1002/grl.50811.

[21] Brian K. Lamb et al., *Direct and Indirect Measurements and Modeling of Methane Emissions in Indianapolis, Indiana,* 50 ENVTL. SCI. TECH. 8910 (2016), 10.1021/acs.est.6b01198.

[22] Gabrielle. Pétron et al., *A New Look at Methane and Nonmethane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin*, 119 J. GEOPHYSICAL RES.: ATMOSPHERES. 6836 (2014), doi:10.1002/2013JD021272.

[23] Jeong et al., *supra* note 11.

[24] Miller et al., *supra* note 18; Bruhwiler et al., *supra* note 18.

[25] Turner et al., *supra* note 18.

[26] Eric A. Kort et al., *Four Corners: The Largest U.S. Methane Anomaly Viewed from Space*, 41 GEOPHYSICAL RES. LETTERS 6898 (2014), doi:10.1002/2014GL061503.

[27] Stefan Schwietzke et al., *Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane*, 48 ENVTL. SCI. TECH. 7714 (2014), doi: 10.1021/es501204c; Mackenzie L. Smith et al., *Airborne Ethane Observations in the Barnett Shale: Quantification of Ethane Flux and Attribution of Methane Emissions*, 49 ENVTL. SCI. TECH. 8158 (2015), doi: 10.1021/acs.est.5b00219.

[28] Anna M. Robertson et al., *Variation in Methane Emission Rates from Well Pads in Four Oil and Gas Basins with Contrasting Production Volumes and Compositions*, 51(15) ENVTL. SCI. TECH. 8832 (2017), doi: 10.1021/acs.est.7b00571; Chris W. Rella et al., *Local and Regional-Scale Measurements of $CH_4$, $\delta^{13}CH_4$ and $C_2H_6$ in the Uintah Basin Using a Mobile Stable Isotope Analyzer*, 8 ATMOSPHERIC MEASUREMENT TECH. 4539 (2015), doi:10.5194/amt-8-4539-2015.

to disaggregate sources if the source ratios of methane to these trace gases are known. Spatially dense atmospheric data can also be used to disaggregate sources whose locations are known.

3. Synthesis

All of these methods have recently been applied at a number of sites across the United States to quantify methane emissions from the oil and gas industry. One conclusion of this research is that individual approaches, when compared, often lead to contradictory results,[29] with atmospheric methods nearly always showing larger total emissions than inventory assessments. A second conclusion is that these methods are complementary and, when employed together, a more complete and consistent understanding of emissions is obtained.[30]

Recent efforts to synthesize results across methods for emissions from the natural gas production chain in the United States have yielded encouraging consistency between plume dispersion and atmospheric budget methods, and suggest that traditional inventory assessments are underestimating emissions.[31] The reasons for the discrepancies are not known with certainty. The leading hypothesis to date based on several studies for explaining the divergence between atmospheric measurement and inventory estimates is that large leaks due to abnormal operating conditions are not accounted for in inventories.[32] Further research is needed to assess why these discrepancies are occurring and develop a systematic approach to emissions measurement.

Current regulatory approaches do not rely on atmospheric monitoring; however, improving measurement and analysis technology, the increasingly clear need for independent evaluation of inventory assessments, and the potential benefits of being able to detect temporal changes in emissions over large areas all suggest that a systematic approach that brought together inventory and atmospheric data, with further development of more comprehensive atmospheric data, could be a valuable addition to the implementation of regulatory measures. Atmospheric monitoring – if done in a cost-effective way (see Section III for economic analysis) – could potentially complement inventory assessments and in so doing, enable new avenues for monitoring and regulation.

*C. Primary Sources of U.S. and Pennsylvania Methane Emissions*

Sources of methane within the United States include all sources important on a global basis, but with larger fractions coming from anthropogenic activities.[33] The oil and gas industries and animal agriculture are estimated to be the two largest sources within the United States, each accounting for approximately 25 percent of total emissions.[34] Wetlands, landfills, and coal mines are

[29] Adam R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 SCI. 733 (2014), doi: 10.1126/science.1247045.

[30] Daniel Zavala-Araiza et al., *Toward A Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites,* 49 ENVTL. SCI. TECH. 8167 (2015); Ramón A. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,* SCI (June 21, 2018), doi: 10.1126/science.aar7204.

[31] Alvarez, *supra.*

[32] Daniel Zavala-Araiza et al., *Super-Emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions*, 8 NATURE COMM., Article Number: 14012 (2017), doi: 10.1038/ncomms14012.

[33] *Greenhouse Gas Reporting Program 2015*, EPA, https://www.epa.gov/ghgreporting/ghg-reporting-program-data-sets (last visited Sept. 3, 2018).

[34] Joannes D. Maasakkers et al., *Gridded National Inventory of U.S. Methane Emissions*, 50 ENVTL. SCI. TECH. 13123 (2016), doi: 10.1021/acs.est.6b02878.

estimated to account for 23 percent, 15 percent, and seven percent of emissions, respectively.[35] While significant uncertainty exists concerning the total U.S. emissions from each of these sources,[36] it is well established that cumulatively, anthropogenic activities represent a large fraction of U.S. emissions and that each of these sources represents a significant contribution to U.S. emissions.

Methane emissions in the Commonwealth of Pennsylvania largely stem from anthropogenic sources. Inventory-based estimates from the 2012 gridded EPA methane inventory suggest that the coal industry is the largest single source of methane in Pennsylvania (38 percent of anthropogenic emissions), followed by oil and gas production, processing, transport and distribution (36 percent), animal agriculture (13 percent), and landfills (11 percent).[37] Wetlands are estimated to account for less than 10 percent of emissions from the Commonwealth of Pennsylvania.[38]

Recent studies in Pennsylvania using atmospheric observations follow the above-described pattern; they find methane emissions from natural gas that are much higher than state and national inventory estimates,[39] consistent with findings from gas production basins across the United States.[40] Adjusting statewide emissions from natural gas using these estimates increases their total contribution to roughly half of Pennsylvania's methane emissions, with the majority of these emissions stemming from natural gas production and gathering processes. More research is needed to comprehensively integrate inventory and atmospheric approaches in Pennsylvania.

1. <u>Oil and Gas</u>

Current national-scale inventory methods do not separate emissions from conventional versus unconventional oil and gas production. The Commonwealth of Pennsylvania provides estimates of emissions from unconventional natural gas production. Recent research in Pennsylvania and elsewhere has attempted to quantify and distinguish emissions from these two sources; knowledge of wells from public data sources can be used to construct separate estimates from conventional and from unconventional production as well as from processing and gathering operations.[41] Transport and distribution systems have also received additional study.[42]

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[35] *Id.*

[36] Brandt et al., *supra* note 29; Miller et al., *supra* note 18; Turner et al., *supra* note 18; Lori M. Bruhwiler et al., *U.S. $CH_4$ Emissions from Oil and Gas Production: Have Recent Large Increases Been Detected?.* 122 J. GEOPHYSICAL RES.: ATMOSPHERES. 4070 (2017), doi:10.1002/2016JD026157.

[37] Maasakkers et al., *supra* note 34.

[38] A. Anthony Bloom et al., *A Global Wetland Methane Emissions and Uncertainty Dataset for Atmospheric Chemical Transport Models,* 10 GEOSCI. MODEL DEV. 2141 (2017), doi:10.5194/gmd-2016-224.

[39] Zachary R. Barkley, Quantifying Upstream Emissions from Natural Gas Production in Northeastern Pennsylvania (2016) (M.S Thesis, Pennsylvania State University), *available at* https://etda.libraries.psu.edu/catalog/6h440s441; Barkley et al., *supra* note 10; Omara et al., *supra* note 10.

[40] Alvarez et al., *supra* note 30.

[41] Barkley et al., *supra* note 10; Omara et al., *supra* note 10; Daniel J. Zimmerle et al., *Methane Emissions from the Natural Gas Transmission and Storage System in the United States*, 49 ENVTL. SCI. TECH. 9374 (2015), doi: 10.1021/acs.est.5b01669; Anthony J. Marchese et al., *Methane Emissions from United States Natural Gas Gathering and Processing*, 49 ENVIRON. SCI. TECHNOL. 10718 (2015), doi: 10.1021/acs.est.5b02275; David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United States*, 110 PROC. NATL. ACAD. SCI. 17768 (2013), https://doi.org/10.1073/pnas.1304880110.

[42] Subramanian et al., *supra* note 5; Brian K. Lamb et al., *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the U.S.*, 49 ENVTL. SCI. TECH. 5161-69 (2015), doi: 10.1021/es505116p; Lamb et al., *supra* note 19; Kathryn McKain et al., *Methane Emissions from Natural Gas*

a. Unconventional Oil and Gas Production

Both peer-reviewed literature and state inventories indicate that unconventional natural gas production in Pennsylvania is currently the most efficient in the United States with respect to methane emissions per unit of gas produced.[43] However, atmospheric and state inventories diverge on the extent of this efficiency, with atmospheric studies indicating that inventory estimates may underestimate emissions by a factor of two or more. Existing atmospheric measurement studies suggest that in Pennsylvania, emissions from upstream unconventional oil and gas are between 0.2 to 0.8 percent of total production.[44] These rates are lower as a fraction of gas produced than rates measured in any other gas basin to date.[45] In contrast, the official state emissions inventory provided by the Pennsylvania Department of Environmental Protection (DEP) estimates an overall emission rate close to 0.1 percent of gas produced. Even with these disagreements in total emissions, inventories for the Commonwealth likely provide valuable data on changes in emissions from sources that are captured by the inventories.

Our ability to monitor changes in methane emissions from unconventional gas production in Pennsylvania is currently limited by a lack of continuous atmospheric data. A key issue discussed throughout both conferences is whether there are large sources that are not accounted for in current inventories, which might explain the discrepancy between inventory and atmospheric data.[46] Evidence for these large leaks comes from site-level, atmospheric dispersion emissions measurements.[47] Confidence in the atmospheric data is based on the fact that these site-level estimates, when aggregated across production basins, agree with regional atmospheric budget emissions estimates.[48] Both of the atmospheric methods show larger emissions than suggested by traditional inventory methods.[49] More data is needed to fully understand these discrepancies.

Atmospheric measurements used to assess Pennsylvania emissions are, to date, all short-term studies. No atmospheric measurements have yet assessed temporal changes in emissions from the Commonwealth. Inventory methods incorporate changes in activity over time (e.g., numbers and locations of wells), but no routine evaluation of emissions factors exists. Given the significant discrepancies between inventory and atmospheric methods, we need more comprehensive data to evaluate inventory assessments; the atmospheric studies to date indicate that the inventories are unlikely to represent accurate assessments of changes in total emissions from natural gas production, but more research is needed.

Finally, even with this efficiency, total methane emissions from unconventional natural gas are an important contributor to Pennsylvania's overall methane budget due to the large amount of

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*Infrastructure and Use in the Urban Region of Boston, Massachusetts*, 112 PNAS 1941 (2015), doi:10.1073/pnas.1416261112.

[43] Omara et al., *supra* note 10; Barkley et al., *supra* note 10; Alvarez et al., *supra* note 30.

[44] Omara et al., *supra* note 10; Barkley et al., *supra* note 10; J. Peischl et al., *Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions*, 120 J. GEOPHYSICAL RES. ATMOSPHERES. 2119 (2015), doi: 10.1002/2014jd022697.

[45] Alvarez et al., *supra* note 30.

[46] *Id*.; David R. Lyon et al., *Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region*, 49 (13) ENVTL. SCI. TECH. 8147 (2015), doi: 10.1021/es506359c.

[47] Omara, *supra* note 10; Lyon et al., *supra.*; Christian Frankenberg, et al., *Airborne Methane Remote Measurements Reveal Heavy-Tail Flux Distribution in Four Corners Region*, 113 PROC. NATL. ACAD. SCI. 9734 (2016), https://doi.org/10.1073/pnas.1605617113.

[48] *Supra* note 30.

[49] Alvarez et al., *supra* note 30.

unconventional gas produced statewide. The large scale of unconventional oil and gas operations in Pennsylvania makes accurately understanding emissions patterns and how to most effectively reduce emissions important.[50]

b. Conventional Oil and Gas Production

Natural gas produced through conventional wells represented only two percent of all gas produced in Pennsylvania in 2017.[51] Though the DEP does not provide a state-level assessment of emissions from these wells, a bottom-up study performed in southwestern Pennsylvania found emissions from conventional wells to be 11 to 15 percent of total production.[52] If this estimate is accurate, total statewide emissions from conventional oil and gas would be comparable to those from unconventional oil and gas despite their minimal comparative contribution to Pennsylvania's energy production. There is not yet suitable large-scale atmospheric data to confirm or refute emissions estimates from conventional gas production. This is another area where more research is needed.

c. Transmission and Distribution

Inventories suggest that natural gas transmission and distribution systems represent less than one percent of methane emissions from the Commonwealth of Pennsylvania. Atmospheric evaluation of transmission systems shows similar totals to national inventories, though much uncertainty still exists in this sector.[53] Atmospheric evaluation of emissions from distribution systems to date has been focused on large urban centers and suggests that emissions may be larger than inventory estimates,[54] but data are sparse, and evidence suggests large city-to-city variability in emissions from distribution systems. Very limited research exists for emissions from these systems within Pennsylvania. More research studies could reduce uncertainties in these emissions, but this would not likely improve our understanding of total emissions from the Commonwealth as significantly as other research proposed in this White Paper since these are expected to be small sources within the Commonwealth.

2. Coal

According to existing inventories, coal mines are a large source of methane emissions,[55] but they have not received much attention in recent scholarly literature on methane emissions. Coal mines in southwestern Pennsylvania are the largest point sources of methane in the Commonwealth; existing atmospheric data confirm the presence of large emissions of methane from this region.[56] The portion attributable to coal cannot yet be precisely quantified using atmospheric data, but both atmospheric data and inventory estimates indicate that cumulatively coal mines are a large source.[57] Additional evaluation of coal mine methane emissions inventories using atmospheric

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[50] Barkley, M.S. Thesis, *supra* note 39.

[51] *Pennsylvania Oil and Gas Production Reports*, PA DEPT. OF ENVTL. PROT., https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx (last visited Sept. 3, 2018).

[52] Omara et al., *supra* note 10.

[53] Zimmerle et al., *supra* note 41.

[54] McKain et al., *supra* note 42; Lamb et al., *supra* note 21.

[55] EPA, *supra* note 7.

[56] Barkley, M.S. Thesis, *supra* note 39; Barkley et al., *supra* note 10; Peischl et al., *supra* note 44.

[57] EPA, *supra* note 7; Barkley, M.S. Thesis, *supra* note 39; Barkley et al., *supra* note 10.

measurements is warranted to provide a comprehensive picture of major sources of methane in the Commonwealth.

3. Animal Agriculture

In Pennsylvania, dairy cows are the most important agricultural source of methane; the highest concentration of emissions is from Lancaster County.[58] Overall, emissions from animal agriculture were estimated by EPA inventories to be 13 percent of methane emissions in Pennsylvania in 2012.[59] Some critical evaluation of agricultural methane emissions inventories with atmospheric data has taken place at national scale[60] and within the state of California,[61] and suggests that emissions may be larger than estimated by inventories. Animal agriculture inventories have been re-evaluated,[62] but regional reconciliation of atmospheric and inventory data is still needed. Focused study of the accuracy of inventory estimates of methane emissions from Pennsylvania agriculture is lacking. This is another area where more data would be valuable in assessing the big picture of methane emissions.

4. Landfills and Other Sources

Landfills and industrial point sources are scattered across the Commonwealth and represent a fraction of total statewide emissions (approximately 11 percent in 2012 according to EPA inventories), similar to totals from animal agriculture.[63] Multiple studies of landfill emissions exist in the scientific literature. At this time, there is no evidence of wide-spread systematic errors in inventory emissions estimates, perhaps reflecting the relative simplicity of quantifying emissions from point sources.

5. Abandoned Wells and Natural Seepage.

A large number of oil and gas wells predating public recordkeeping exist in Pennsylvania (about half a million from a recent survey).[64] There are no comprehensive estimates of emissions from these sites. Limited point measurements suggest that these could constitute a small but significant source,[65] but this has not yet been detected with regional-scale atmospheric measurements. Less is known about total emissions from natural seepage. Evidence exists that this is a small but significant source globally,[66] but estimates of emissions at regional level are not available. As with abandoned wells, no direct evidence of large emissions in the

[58] Maasakkers et al., *supra* note 34; Barkley, M.S. Thesis, *supra* note 39.

[59] Maasakkers, et al., *supra* note 34.

[60] Miller et al., *supra* note 18.

[61] Jeong et al., *supra* note 11.

[62] Alexandar N. Hristov et al., *Discrepancies and Uncertainties in Bottom-up Gridded Inventories of Livestock Methane Emissions for the Contiguous United States*, 51 ENVTL. SCI. TECH. 13668 (2017), doi: 10.1021/acs.est.7b03332.

[63] Maasakkers, et al., *supra* note 34.

[64] Mary Kang et al., *Direct Measurements of Methane Emissions from Abandoned Oil and Gas Wells in Pennsylvania*, 111 PROC. NAT'L ACAD. SCI. 18173 (2014), doi:10.1073/pnas.1408315111; James I. Sams et al., *Methods and Challenges to Locating Legacy Wells in Western Pennsylvania: Case Study at Hillman State Park*, 24 ENVTL. GEO SCI. 95 (2017), doi:10.1306/eg.1221161600417009.

[65] Robert M. Dilmore et al., *Spatial and Temporal Characteristics of Historical Oil and Gas Wells in Pennsylvania: Implications for New Shale Gas Resources*, 49 ENVTL. SCI. TECH. 12015 (2015), doi: 10.1021/acs.est.5b00820.

[66] Ciais et al., *supra* note 1.

Commonwealth of Pennsylvania has yet been found via regional atmospheric observations.[67] Additional study could reduce the large degree of uncertainty in these emissions. Evidence to date, however, suggests that these sources are unlikely to account for a large fraction of methane emissions from the Commonwealth of Pennsylvania.

### *D. Methane Emissions in the Broader Context of Statewide Greenhouse Gas Emissions*

#### 1. Overview of Pennsylvania Greenhouse Gas Emissions

Although this pilot project has focused on methane emissions, it is important to understand them in the overall context of greenhouse gas emissions in Pennsylvania. Carbon dioxide emissions from the combustion of fossil fuels, including coal, oil and natural gas, are the dominant source of the Commonwealth's greenhouse gas emissions. Methane emissions from unconventional oil and gas are a comparatively modest contributor to Pennsylvania's overall greenhouse gas emissions. A precise description of this issue is complicated, however, by both the global warming potential of methane versus carbon dioxide, and uncertainty in methane emissions from the Commonwealth.

Based on EPA and DEP inventory data, in 2015 Pennsylvania emitted 230 Tg carbon dioxide and 1.6 Tg methane.[68] Methane's global warming potential is 28 times larger per unit of mass than carbon dioxide over a 100-year period, and 84 times larger over a 20-year period.[69] Weighting for this factor, methane contributed from 16 percent (100-year time frame) to 37 percent (20-year time frame) of Pennsylvania's 2015 greenhouse gas emissions. DEP inventories estimate that 0.1 Tg of Pennsylvania's methane emissions can be attributed to unconventional gas production in 2015.[70] In the context of statewide greenhouse gas emissions, methane emissions from unconventional production in 2015 were responsible for one percent (100-year time frame) to two percent (20-year time frame) of Pennsylvania's overall greenhouse gas emissions. As noted above, atmospheric observations have found that DEP emission estimates from natural gas production are likely to be low by a factor of two or more. If emissions from unconventional gas were estimated at a higher 0.3 Tg methane per year in 2015, then total 2015 methane emissions would be 1.8 Tg methane, with 18 percent (100 year) or 40 percent (20 year) of the Commonwealth total greenhouse gas footprint coming from methane, and 2.5 percent (100 year) and seven percent (20 year) coming from unconventional gas production.

#### 2. Consequences of Unconventional Natural Gas Production on Pennsylvania Greenhouse Gas Emissions

The shift away from coal combustion and towards natural gas has probably contributed to a decline in total Commonwealth carbon dioxide emissions over the past several years. Leakage of methane from the natural gas production process, however, counterbalances some of the benefit of reduced carbon dioxide emissions. EPA inventory data suggest that carbon dioxide emissions

[67] Barkley et al. (2017), *supra* note 10.

[68] *See supra* sources cited in note 39; *Pennsylvania Greenhouse Gas Inventory 2016*, Dept. Envtl. Prot., http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Advisory%20Committees/CCAC/Docs/Inventory-2016_1-18-17_(final).pdf (last visited Sept. 3, 2018); Maasakkers et al., *supra* note 34.

[69] Ciais et al., *supra* note 1.

[70] *PA DEP Marcellus Inventory 2015*, PA Dept. of Envtl. Prot., https://www.dep.pa.gov/Business/Air/BAQ/BusinessTopics/Emission/Pages/Marcellus-Inventory.aspx (last visited Sept. 3, 2018).

in Pennsylvania have decreased from 274 Tg $CO_2$ in 2007 to 230 Tg $CO_2$ in 2015.[71] Much of the decrease in carbon dioxide emissions during this period can be traced to changes in the Commonwealth's energy consumption. From 2008 to 2015, Pennsylvania production of energy via combustion of coal decreased by 40 percent (500 trillion Btu (British thermal units)) while the production of energy via combustion of natural gas increased by 70 percent (430 trillion Btu).[72] Because the combustion of coal produces roughly twice as much carbon dioxide per Btu generated compared to the combustion of natural gas, this energy shift has major repercussions on statewide carbon dioxide emissions. A changeover from coal to gas at the levels observed in Pennsylvania would reduce $CO_2$ emissions by 40 Tg $CO_2$, and thus is likely responsible for a large portion of the inventory-reported decrease in $CO_2$ emissions over the last decade.[73] If we estimate the emissions of methane from unconventional gas production to range from 0.1 Tg $CH_4$ per year to 0.5 Tg $CH_4$ per year, apply the 100- and 20-year global warming potentials, and assume that this increase in emissions occurred from 2007 to 2015, then the annual added leakage of methane from unconventional natural gas production ranges from 3 to 14 Tg $CO_2$e ($CO_2$ equivalent) for a 100-year time window, to 8 to 42 Tg $CO_2$e for a 20-year time window. It thus appears that the increased production of natural gas and decreased combustion of coal in the Commonwealth is likely to have reduced the Commonwealth's overall greenhouse gas footprint on the 100-year time frame, but may yield little net benefit on a 20-year time frame. It is important to note that we have considered methane leakage only from production in this calculation; increased emissions farther along the supply chain would increase the net climate impact of natural gas as a fuel.

It is also important to note that our assessment only considers greenhouse gas emissions from within the borders of the Commonwealth. Gas produced within the Commonwealth may displace coal combustion, or the development of renewable energy sources, outside of the Commonwealth. A complete assessment of the net impact of Pennsylvania unconventional natural gas production on greenhouse gas emissions and other environmental and economic issues is beyond the scope of this document. It is possible that regulation that considers only a portion of greenhouse gas emissions (e.g., methane and not carbon dioxide) could inadvertently favor energy sources with larger greenhouse gas footprints. Other environmental impacts of these energy sources – for example, air and water quality, human health, and ecosystem impacts – also deserve consideration.

3. <u>Other Potential Pathways towards Reducing Pennsylvania Greenhouse Gas Emissions</u>

Reducing greenhouse gas emissions through reducing unconventional natural gas methane emissions must be analyzed in the broader context of sources of greenhouse gases in Pennsylvania. The greatest potential for reducing Commonwealth greenhouse gas emissions lies

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[71] *State CO2 Emissions from Fossil Fuel Combustion*, EPA, https://www.epa.gov/statelocalenergy/state-co2-emissions-fossil-fuel-combustion (last visited Sept. 3, 2018); *Pennsylvania Greenhouse Gas Inventory 2016*, Dept. Envtl. Prot., http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Advisory%20Committees/CCAC/Docs/Inventory-2016_1-18-17_(final).pdf (last visited Sept. 3, 2018); Maasakkers *et al.* (2016), *supra* note 34.

[72] *Pennsylvania Energy Consumption*, Envtl. Info. Admin., https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_use/total/use_tot_PAcb.html&sid=PA (last visited Sept. 3, 2018).

[73] *How much Carbon Dioxide is Produced when Different Fuels are Burned*, Envtl. Info. Admin., https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 (last visited Sept. 3, 2018).

in the reduction of carbon dioxide emissions from the consumption of fossil fuels. If emissions from unconventional natural gas production are kept at a low level, a transition from coal to natural gas in the production of electricity will reduce the Commonwealth's total greenhouse gas footprint,[74] but only to a limited extent. Reduction in emissions of methane from unconventional gas production has only modest potential for reducing total Commonwealth greenhouse gas emissions. Reducing methane emissions from other sources in the Commonwealth is another option. All of these pathways towards greenhouse gas emissions reductions are worth exploring. A complete assessment of these options is outside the scope of this White Paper.

### *E. Impacts Associated with Methane Release*

Methane emissions are associated with three primary harms: climate change, explosion risk, and contribution to ozone formation. This section briefly discusses those harms.

#### 1. Potent Greenhouse Gas Resulting in Climate Change

Methane is a potent greenhouse gas with many times more impact on global radiative forcing per molecule than carbon dioxide; methane is currently responsible for 20 to 25 percent of the current total anthropogenic radiative forcing that is causing climate change.[75] Since the earth's atmosphere mixes any emissions from the earth's surface across the entire globe in about one to two years, local emissions of methane impact the global climate. Atmospheric methane concentrations reach equilibrium with emissions within a couple of decades,[76] meaning that atmospheric methane concentrations are relatively more manageable than longer-lived carbon dioxide concentrations.

#### 2. Explosion Risk

High concentrations of methane lead to the risk of explosion; it can form an explosive mixture with air, easily ignited by heat sources from vehicles or equipment. This risk is the subject of considerable existing regulation and testing. Many current leak detection and repair regulations stem primarily from this concern. [77]

#### 3. Contribution to Ozone Formation

Methane is a photochemical precursor to ozone. Oxidation of methane and other volatile hydrocarbons can result in the formation of ozone in the lower atmosphere; localized sources of ozone irritate the respiratory systems of animals and damage plants.[78] Given its relatively slow

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[74] Ramón A. Alvarez et al., *Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure*, 109 PROC. NAT'L ACAD. SCI. 6435 (2012), https://doi.org/10.1073/pnas.1202407109.

[75] Ciasis, *supra* note 1.

[76] JOHN H. SEINFELD & SPYROS N. PANDIS, ATMOSPHERIC CHEMISTRY AND PHYSICS: FROM AIR POLLUTION TO CLIMATE CHANGE (Wiley, 2016).

[77] Aaron G. Cahill et al., *Mobility and Persistence of Methane in Groundwater in a Controlled-Release Field Experiment*, 10 NATURE GEOSCIENCE 289 (2017), doi: 10.1038/ngeo2919; *OSH Answers Fact Sheet: Methane*, CANADIAN CENTRE FOR OCCUPATIONAL HEALTH AND SAFETY (CCOHS), https://www.ccohs.ca/oshanswers/chemicals/chem_profiles/methane.html (last updated Aug. 22, 2018).

[78] SEINFELD & PANDIS, *supra* note 76; Alvarez et al., *supra* note 30; See ZOTERO, https://www.zotero.org/groups/248773/pse_study_citation_database (last visited Aug. 1, 2018). The large number of associative studies that have been published that describe reported health impacts among residents

rate of oxidation, however, methane has a relatively modest contribution to the formation of ozone in areas like Pennsylvania where other more reactive hydrocarbon sources exist. While a concern, local air quality is not typically the primary concern associated with methane emissions.[79]

### *F. Recommendations for Future Study of Methane Emissions in Pennsylvania*

#### 1. <u>Research Is Needed to Evaluate the Divergence of Atmospheric and Inventory Approaches</u>

Emissions regulations based on accurate emissions data are most likely to be effective and efficient. Research is needed to systematically evaluate what is causing the divergence between inventory and atmospheric measurements. Current emissions inventories appear to be fairly accurate for the emissions they represent.[80] Therefore, to the extent that current regulations are targeted to reduce the largest sources of emissions found in these inventories, they are likely to be effective in reducing this portion of methane emissions. In addition, current requirements for increased emphasis on leak detection and repair are likely to be effective and may assist in reducing the emissions that appear to be missing currently from inventories.

However, the divergence between inventory data and atmospheric studies suggests that Pennsylvania methane emissions inventories for unconventional natural gas production may not be including some important sources. Other inventory estimates remain largely untested at a state level, and testing at a national level is limited. Additional research that systematically evaluates inventory-based methane emissions estimates is needed to obtain accurate emissions estimates for distributed sources such as animal agriculture, natural gas production, natural gas distribution systems, and abandoned wells. Given the magnitude of emissions within the Commonwealth and data uncertainties, further research of natural gas production from both conventional and unconventional methods is critical, as is further study of the significant statewide agricultural emissions. Additional research into the less uncertain but large magnitude coal and landfill emissions estimates is also warranted.

Systematic monitoring of emissions over time using atmospheric methods could be employed to evaluate attempts to reduce emissions from any of these sources. Advances in atmospheric measurement technology, using both in situ and remote sensing techniques, are occurring rapidly. The Commonwealth of Pennsylvania would be well served to stay abreast of this technology and actively consider employing these tools to better understand statewide methane emissions. Current atmospheric data are limited in density. A first step towards pursuing this recommendation would be to decide which inventory estimates are most important to evaluate, and over what time span. A second step would be to consider appropriate strategies for increasing the density of suitable atmospheric methane observations.

Improvements also could be made to inventories via more frequent updates of emissions factors. Activity data (e.g., numbers of wells and compressor stations, length of pipelines, production data)

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near natural gas production facilities. Many of these rely on self-reporting for data collection, and no study to date has completed a long-run analysis that is able to make causal linkages. A large number of the existing studies can be accessed through the PSE study citation database. *See id.*

[79] CCOHS, *supra* note 77.

[80] Alvarez et al., *supra* note 30.

can be maintained with required public reporting from the industry.[81] Reevaluating the emissions factors, however, is much more time consuming and challenging; in addition, emissions factors can change as technology evolves.[82]

2. Research Is Needed to Assess Large Point Source Emissions

A major result of recent study of methane emissions from unconventional gas production is the finding that a large portion of emissions appears to be coming from sources that (1) are not included in emissions inventories and (2) come from a relatively small number of point sources.[83] For example, a study of well emissions from four basins finds that 20 percent of well sites are responsible for 80 percent of all well-pad emissions.[84] A similar distribution of emissions was found to be true for compressor facilities.[85] These large emissions could be from either planned releases or unplanned equipment failures.[86]

This research has at least two implications for the Commonwealth. First, research is needed to confirm or refute this finding; if confirmed, identifying the nature of these emissions is essential to coming to a more complete understanding of these emissions, and to providing clear guidance on the potential for emissions mitigation. Methane emissions from unconventional gas production are significant; the climate benefit of this fuel source is dependent on production with minimal leakage to the atmosphere. Pennsylvania gas production is currently the most efficient in this regard of all the gas basins evaluated in the United States. The Commonwealth's advantage in this area could be enhanced with better understanding of this discrepancy between inventories and atmospheric measurements, and thus better understanding of how to reduce these emissions. Second, these results strongly suggest that leak detection and repair is likely to be a very effective measure for reducing methane emissions. Technology for leak detection and repair is an area of active research and development. Regulatory approaches that encourage and adapt to technological developments in this area would therefore be advantageous.

Regional atmospheric data would complement the current inventory assessment methods and leak detection and repair. These data could potentially be used to develop new regulatory options. For example, regional emissions, aggregated over many sources, could be regulated instead of, or in addition to "best available technology" regulations. If regional emissions targets were met, regulations would be satisfied regardless of the means used to achieve this emissions target. Such an approach would require that regional maximum emissions targets are identified, and that monitoring methods are adopted. Monitoring statewide emissions would bring the added benefit of knowledge of all emissions from the state, enabling a more comprehensive approach to the regulation of methane emissions from its many sources. As with leak detection, technology for monitoring regional emissions is developing fairly rapidly. Regulatory frameworks that can accommodate evolving technology would be ideal. However, since no regulations using this type

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[81] ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSION AND SINKS: 1990-2013, ANNEX 3.6 (2015), *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015.

[82] ENVTL. PROT. AGENCY, INVENTORY OF US GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1996 (1998), *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-1996.

[83] Omara et al., *supra* note 10; Zimmerle et al., *supra* note 41; Marchese et al., *supra* note 41; Lyon et al., *supra* note 46; Karion et al., *supra* note 10.

[84] Robertson et al., *supra* note 28.

[85] Subramanian et al., *supra* note 5.

[86] Subramanian et al., *supra* note 5 (re: compressors); Robertson et al., *supra* note 28 (re: wells).

of technological approach currently exist for methane emissions, careful evaluation of this approach would be necessary.

## III. Economic Dimensions of Methane Emissions Mitigation

Unlike other air emissions that contribute to global climate change or degrade local air quality, methane has the property of being a saleable product. Industry thus has internal economic incentives to reduce the frequency and magnitude of methane emissions, as methane molecules that escape are those that cannot be sold. The incentives of private industry, in the absence of any regulatory intervention, would be to engage in emissions mitigation practices that will pay for themselves at the market price of natural gas.

At the same time, methane emissions (not just from natural gas operations, but from multiple sources as described in Section II.C) involve costs that are more widely dispersed at the local scale (e.g., ozone formation) or at the global scale (e.g., climate change) and are borne by segments of society other than industry. A major economic goal of environmental regulation is to align the decisions of industry (or other sources of environmental emissions) with social costs rather than internal costs.

Additionally, regulation itself imposes costs – the adoption of technological interventions to reduce methane emissions in natural gas production, for example, will increase production costs for natural gas. If those production costs rise substantially, then consumers of natural gas will seek substitutes for natural gas produced in Pennsylvania or in other locations. Substitutes may include natural gas produced abroad (via liquified natural gas or pipeline shipments) or other fuels such as coal for the generation of electricity. The amount of substitution will depend on the relative price increase of natural gas relative to other possible fuels or the price of natural gas in Pennsylvania relative to other locations, and other technology costs involved in fuel substitution (e.g., switching from natural gas heating to oil heating involves the cost of a new furnace). The emergence of Pennsylvania as a major natural gas producer has resulted in spot natural gas prices in the region falling below national benchmarks. Prices at major production hubs in the Marcellus play have averaged between $0.90/MCF and $0.97/MCF below the national benchmark Henry Hub price for the past three years.[87] This may change with shifts in overall natural gas demand and the construction of additional transmission capacity to move gas produced in Pennsylvania to other locations.

Evaluating costs and benefits for specific state mechanisms to regulate methane emissions is made difficult by poor or non-existent data along two dimensions. First, the compliance costs for some technology options are difficult to assess in specific state contexts, particularly prior to wide-scale deployment. The Pennsylvania DEP has made public some cost estimates for Leak Detection and Repair (LDAR) technologies in its Technical Support Document for General Permits 5 and 5A.[88] Deployed technology costs, however, will depend on compliance technology decisions by individual operators and experience with these technology choices in Pennsylvania.

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[87] These figures are based on the average difference between spot gas prices at the Henry Hub and spot prices in the Dominion North and South Zones, and the Transco Leidy Zone for the period July 2015 to July 2018. Price data was obtained from SNL.

[88] PA DEPT. OF ENVTL. PROT., TECHNICAL SUPPORT DOCUMENT: GENERAL PLAN APPROVAL AND GENERAL OPERATING PERMIT FOR UNCONVENTIONAL NATURAL GAS WELL SITE OPERATIONS AND REMOTE PIGGING STATIONS (BAQ-GPA/GP-5A) AND FOR

An additional complication in evaluating the cost of regulatory compliance is that these costs may vary widely by operator, based on technology adoption at the time that regulations are enacted, and even the location of the operator. Data on technology adoption at the operator level is not widely shared in the public domain. Regulations that require technologies or practices already in use will necessarily have low (or zero) incremental cost as long as the technologies or practices used in the field are treated as equivalent to those specified in regulations. Additionally, the kinds of technology interventions required to abate significant emissions sources may vary based on field characteristics (e.g., whether holding tanks are used on-site for storage of natural gas liquids).

These data gaps make it hard to assess the economic efficiency of different state regulatory approaches, and limit comparative analysis. Researchers have conducted multiple point-based measurement studies at specific locations,[89] but no state or federal regulatory agency to our knowledge has established an ongoing program for sustained on-site or atmospheric measurements. We can estimate the emissions abatement implications from regulations in Pennsylvania and other states based what we know from inventory data and the results of multiple research efforts to measure methane emissions on-site and at the atmospheric level, but there will necessarily be important sources of uncertainty in these estimates.

This Section uses the case study of Pennsylvania's revisions to the permitting process to provide a framework for benefit-cost assessment based on national inventory data. Pennsylvania's 2018 General Permit revisions serve as a particularly good case example of this issue because they focus on specific technology requirements more than some of the other states. This highly prescriptive approach, because it is so specific, makes it easier to try to construct estimates of cost and effectiveness in advance of regulatory requirements being fully adopted.

Based on these national-level estimates, it appears that Pennsylvania's permit revisions specifically target many of the largest sources of methane emissions across the natural gas value chain, although the achievable emissions reductions depend on the breadth of application of the proposed regulatory requirements. Some requirements appear to apply only to new sources while others would apply to existing sources of specified vintages. Moreover, if emissions inventory assessments are incomplete because they do not capture large leaks associated with abnormal operations (as discussed in Section II), the focus on LDAR requirements is sensible.

A limited number of analyses have attempted to build methane emissions abatement cost curves for the unconventional natural gas sector at a national level.[90] These cost curves show the

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NATURAL GAS COMPRESSOR STATIONS, PROCESSING PLANTS, AND TRANSMISSION STATIONS (BAQ-GPA/GP-5) 66, Appendix E (2017), http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-116052/Technical%20Support%20Document%20GP-5%20and%205A.pdf.

[89] Omara et al., *supra* note 10. Required reporting of air emissions to the Pennsylvania DEP under Act 13 is currently based largely on published emissions inventories and emissions factors from the US EPA Inventory of Greenhouse Gas Emissions. Facility reporting data is available at http://www.ahs.dep.pa.gov/eFACTSWeb/reports.aspx.

[90] *See* the U.S. Inventory of Greenhouse Gases produced by Envtl. Prot. Agency; *See* ICF INTERNATIONAL, ECONOMIC ANALYSIS OF METHANE REDUCTION OPPORTUNITIES IN THE US ONSHORE OIL AND NATURAL GAS INDUSTRIES (EDF, 2014), https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf; *See* ICF INTERNATIONAL, ECONOMIC ANALYSIS OF METHANE EMISSION REDUCTION POTENTIAL FROM NATURAL GAS SYSTEMS (EDF, 2016), http://www.onefuture.us/wp-content/uploads/2016/06/ONE-Future-MAC-Final-6-1.pdf. Resources for the Future has some public analysis of the costs of methane control for conventional versus unconventional wells.

engineering costs of different technology options for reducing methane emissions, along with an estimate of the potential emissions reduction if those technology options were adopted uniformly across the natural gas value chain. The costs of any specific option may vary depending on location, which introduces some uncertainty in evaluating the cost of compliance with Pennsylvania's permit revisions and the potential impacts on industry and consumers of natural gas, electric power and manufactured goods that use natural gas or associated liquids as feedstock.

Figure 1 shows a methane abatement cost curve constructed for Pennsylvania based on *national-level cost estimates* of some methane control measures under consideration in Pennsylvania, as well as some methane control measures described in national-scale studies of methane abatement from the unconventional natural gas sector not considered for adoption under General Permits 5 and 5A. The bars in the figure show the average engineering cost of a single unit of methane emissions abatement via each technology intervention (i.e., the engineering costs per unit of methane that stays in the natural gas supply system for ultimate sale and consumption). The width of each bar represents an estimate of total abatement potential in Pennsylvania, in percentage terms, based on national level analyses.[91] These methane abatement costs can be compared to regionally appropriate market prices for natural gas to provide a sense of those options that would be most cost-effective for industry to adopt without any regulatory pressure.[92] This analysis of internal costs and benefits to operators (without differentiating portions of the supply chain, e.g., upstream versus midstream) suggests that industry in Pennsylvania has internal incentives to substantially reduce methane emissions if operators in Pennsylvania were not currently employing any of the technology options shown in the figure. The cost-effective abatement potential for operators ranges from 35 percent of total emissions in Pennsylvania (if inventory numbers are used; this is the situation shown in Figure 1) to 60 percent of total emissions (if recent research on point-based emissions figures from upstream activities are used).[93]

The marginal abatement cost curve in Figure 1 can be useful in understanding the costs of different technology options relative to one another. The construction of the cost curve and application to Pennsylvania specifically involves some strong assumptions not only about the similarity of technology costs and emissions distributions in Pennsylvania versus producing basins in other parts of the United States, but also about emissions magnitudes and operator practices. These assumptions highlight important data gaps that could be filled through collaborative research with industry and government. First, the emissions proportions shown in the horizontal axis of Figure 1 are taken from national-level analyses that have used EPA emissions inventories.

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*See* A. Krupnick, *Methane Emissions in the Oil and Gas Sector: Two Recent RFF Projects* (presentation at the RFF-Stanford Woods Webinar series, 2016), *available at* http://www.rff.org/events/event/2016-09/cost-effective-approaches-managing-methane-emissions-us-oil-and-gas.

[91] *See supra,* ICF INTERNATIONAL (2016),

[92] The price series that we use in Figure 1 is a one-year average of the daily Appalachian Hub index from Natural Gas Intelligence (http://www.naturalgasintel.com/data/data_products/daily). Even this index masks some regional differences in the value of natural gas in different areas of Pennsylvania. *See* Energy Info. Admin, *Spread Between Henry Hub, Marcellus Natural Gas Prices Narrows as Pipeline Capacity Grows,* TODAY IN ENERGY (Jan. 27, 2016), https://www.eia.gov/todayinenergy/detail.php?id=24712.

[93] Alvarez, *supra* note 30, notes that point-based measurement studies suggest that methane emissions from production and gathering activities are close to 75% of total methane emissions across the entire natural gas value chain. National level cost estimates for technologies that could be applied to production and gathering activities suggest that 80% of potential emissions control for production and gathering would be internally worthwhile economically.

Figure 1 thus assumes that the inventories have captured the proportion of emissions from different segments of the natural gas value chain correctly. Since atmospheric measurements diverge from inventory assessments for some segments of the natural gas value chain (particularly production and gathering as discussed in Section II), the *proportion* of total potential methane abatement possible with different technology options may be underestimated for some technology options and consequently overestimated for other technology options. Second, marginal abatement cost curves such as Figure 1 assume that no operator is using any technology option shown in the figure. To the extent that the marginal abatement cost curve shows technology options that have already been widely adopted, the incremental abatement potential for those options will be overestimated by the abatement cost curve. Since there is no public data source on which operators in Pennsylvania or other states are utilizing the technology options shown, the best we can do is acknowledge this strong assumption and identify it as a data need to improve abatement cost curves.

Marginal abatement cost curves can also be used to compare technology costs to the social benefits of avoiding methane emissions. The classic cost-benefit criterion is to compare the cost of an abatement technology or practice to the social cost of the methane that would have been emitted in the absence of the control technology. Various efforts have attempted to estimate the social cost of methane emissions; these estimates are uncertain and also can be politically charged. These numbers are important, however, because balancing private decisionmaking and social costs is part of the purpose of air emissions regulation. The higher that the social costs are judged to be, the more aggressive control measures can be justified on the basis of society's welfare as a whole. For the sake of comparison, Figure 1 shows two very different estimates of the social cost of methane. The first, consistent with the majority of scientific evidence and consistent with the approach adopted by the EPA prior to November 2017, suggests a social cost of methane of between $27 and $30 per thousand cubic feet emitted.[94] Under such a social cost, virtually any technological intervention on the upstream or midstream segments of the natural gas supply chain would be judged as cost-effective. Recent interim revisions to the EPA's social cost of methane, however, would place social costs below market prices (around $1.35 per thousand cubic feet emitted).[95] Under such a standard, the benefits of many technological interventions would exceed implementation costs.

The bars in Figure 1 represent engineering costs per unit of methane emissions abated. We also estimate the average impact on natural gas production costs for each emissions abatement technology, shown as a range in parentheses beside each technology option for which the

[94] Alex L. Marten et al., *Incremental $CH_4$ and $N_2O$ Mitigation Benefits Consistent with the US Government's SC-CO2 Estimates*, 15(2) CLIM. POLICY 272 (2015), doi:10.1080/14693062.2014.912981; Alex L. Marten et al., *Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide*, 11(1) NCEE WORK. PAP. SER. (2011), doi:10.1016/j.enpol.2012.09.073; Drew Shindell et al., *The Social Cost of Methane: Theory and Applications*, 200 FARADAY DISCUSS. 429 (2017), doi:10.1039/C7FD00009J; Richard S. J. Tol et al., *Methane Emission Reduction: An application of FUND*, 57 CLIM. CHANGE 71 (2003), doi:10.1023/A:1022196517982; Stephanie Waldhoff et al., *The Marginal Damage Costs of Different Greenhouse Gases: An Application of FUND*, 8 ECON. DISCUSS. PAP. (2011), doi:10.5018/economics-ejournal.ja.2014-31.

[95] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements, 82 Fed. Reg. 27645 (proposed on June 6, 2017) (to be codified at 40 C.F.R. pt. 60). A principal reason for the lower social cost of methane in the EPA's proposed revision is the decision to exclude climate-related damages that occur outside of the United States. *See* Niina Heikkinen, *EPA Revises the Social Cost of a Potent Greenhouse Gas*, SCIENTIFIC AMERICAN (Nov. 20, 2017), https://www.scientificamerican.com/article/epa-revises-the-social-cost-of-a-potent-greenhouse-gas/.

estimated production cost impact is greater than one cent per thousand cubic feet. These impacts on natural gas production costs are constructed using the following procedure:

- We first estimate a range of total methane emissions for the unconventional oil and gas sector in Pennsylvania, assuming that somewhere between 0.1 percent of total unconventional natural gas production (the figure suggested by inventory data, as discussed in Section II) and 0.4 percent of total production is lost (as suggested by point-based measurements from upstream systems as described in Section II). In order to develop a range, we assume that the 0.1 and 0.4 percent figures represent total production losses across all segments of the natural gas value chain. Based on the total unconventional production number of 5.4 trillion cubic feet as reported by the Pennsylvania DEP for 2017,[96] this yields a total methane emissions range of 54,000 to 216,000 million cubic feet per year.

- We use the proportions in Figure 1 and total methane emissions estimates from the first step to estimate a total methane abatement potential for each technology option.

- The cost of each option per million BTU of avoided methane emissions is used with the estimated total methane abatement potential from the second step to estimate a total abatement cost for each technology option.

- These total costs are then spread across all production in Pennsylvania, which effectively assumes that all operators in Pennsylvania (both upstream and midstream) have adopted all technology options shown in Figure 1.

The average cost analysis shown in Figure 1 does not consider heterogeneity in abatement costs across producers and across segments of the natural gas supply chain but is useful to get a sense as to how the adoption of mitigation technology may affect natural gas supply costs in Pennsylvania. The analysis in Figure 1 suggests that adoption of methane mitigation technology would not, *on average*, raise natural gas supply costs in Pennsylvania by more than 7 percent. (Again, we acknowledge that the cost impacts would probably be spread unevenly across operators and segments of the natural gas supply chain). Based on recent estimates of the sensitivity of inter-fuel competition to natural gas prices, cost increases of this magnitude would lead to very limited substitution of other fuels for natural gas.[97]

We reiterate that the accuracy of this analysis is fundamentally impacted by the data questions discussed in Section II. The percentage range that we use for production lost to leaks or abnormal operations may not ultimately be the correct percentage once a comprehensive analysis is conducted. The distribution of emissions may also be quite different from what is assumed in

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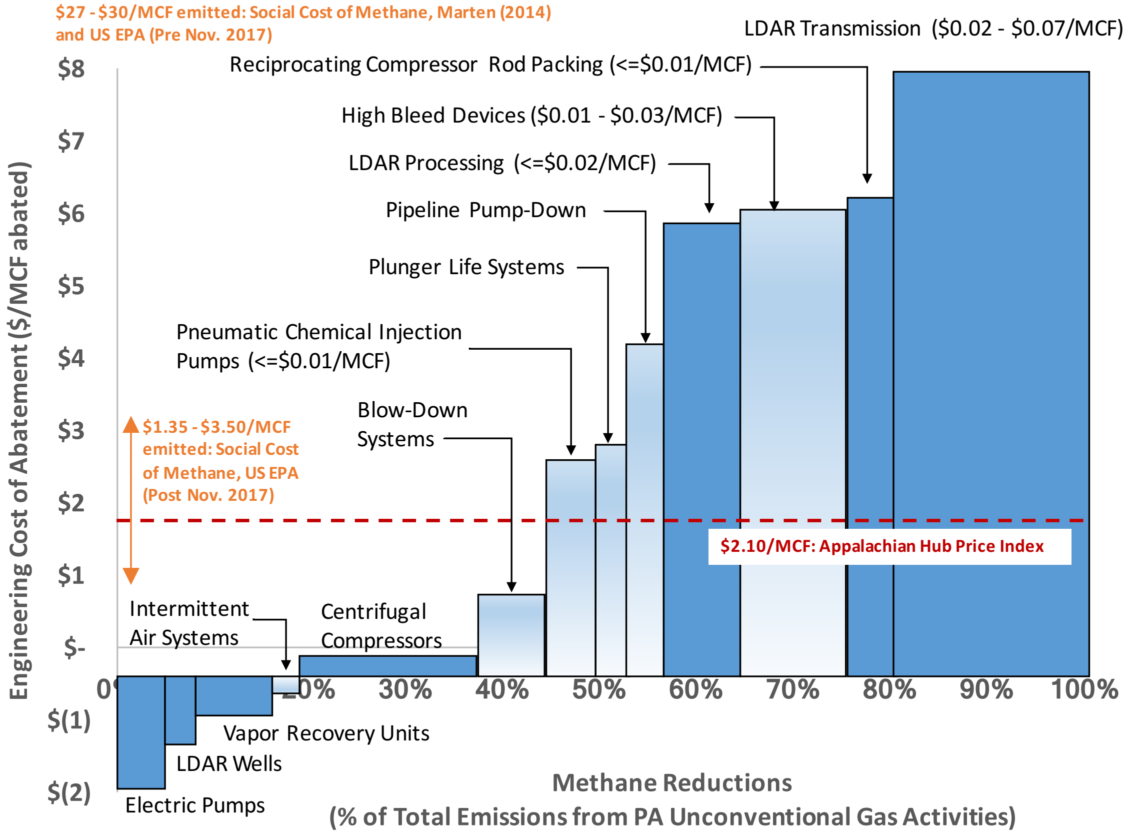
[96] *Oil and Gas Reports*, PA DEPT. ENVTL. PROT., https://www.dep.pa.gov/DataandTools/Reports/Oil%20and%20Gas%20Reports/Pages/default.aspx, (last visited Aug. 28, 2018).

[97] We use the elasticities of substitution published in ENVTL. INFO. ADMIN., FUEL COMPETITION IN POWER GENERATION AND ELASTICITIES OF SUBSTITUTION (2012), https://www.eia.gov/analysis/studies/fuelelasticities/pdf/eia-fuelelasticities.pdf. This analysis suggests that a 10% increase in natural gas prices relative to those of other fuels would induce a 1.4% increase in the use of other fuels relative to natural gas. Similar results are reported in Levan Elbakidze & Gulnara Zaynutdinova, *Substitution in Electricity Generation: A State Level Analysis of Structural Change from Hydraulic Fracturing Technology,* AGRICULTURAL AND APPLIED ECONOMICS ASSOCIATION 2016 ANNUAL MEETING (July 31-August 2, 2016).

inventories. For example, further research into whether large point sources are adding emissions beyond inventory estimates or how much production emissions contribute might help refine this number.

*Figure 1: Methane abatement costs, relative to regionally appropriate natural gas prices and different values for the social cost of methane emissions, for various control options.*




*The width of the bars represents the approximate proportion of methane abatement if measures were applied uniformly across both existing and new facilities. Darker blue bars indicate abatement options that are covered in the revisions to Pennsylvania General Permits 5 and 5A, while lighter blue bars indicate options that are not covered. Figures in parentheses indicate the natural gas production cost increase (averaged over all natural gas production in Pennsylvania) associated with each technology option. Those technology options without associated costs in parentheses are estimated to increase production costs by less than one cent per thousand cubic feet, again averaged over total Pennsylvania natural gas production. Methane abatement quantities are based on inventory emissions data; recent point-based measurements suggest that the distribution of total emissions from production and gathering activities may be higher than reported in inventories.*

We focus on Pennsylvania as an example of cost-effectiveness in the context of specific technology requirements. The technologies evaluated in these national-level cost estimates appear to be consistent with the Best Available Control Technologies as described in the technical supplement to Pennsylvania's proposed revisions to General Permits 5 and 5A.[98] Since technologies and costs are constantly evolving, these figures should be taken as a reasonable snapshot at the present time rather than a firm projection of costs and technology options going forward.

[98] PA DEPT. ENVTL. PROT., TECHNICAL SUPPORT DOCUMENT, *supra* note 88, at 20 and Appendix E.

Applying these national-level cost estimates to Pennsylvania's natural gas activities may not be straightforward. While there is likely less regional variation in the cost of hardware-based mitigation measures such as pumps or degassing recovery, the effectiveness of these measures can vary by a factor of three or higher depending on the operational situation.[99] The effectiveness of leak detection is even more uncertain, with orders of magnitude variation depending on the location of the detection unit relative to the assumed leak point.

An additional complication in assessing the cost-effectiveness of methane regulations in Pennsylvania is the differential treatment of new and existing sources. Some requirements from the revisions to General Permits 5 and 5A would apply only to new sources, while others would apply to some existing sources but exempt others of varying vintages. The implications for the potential control of methane emissions are significant. Figure 1 suggests that roughly 80 percent of methane emissions from the unconventional natural gas value chain in Pennsylvania (including compression, processing and transmission, which service both conventional and unconventional production) would be addressed by Pennsylvania's methane emissions mechanism if technology requirements were uniformly applied to both new and existing sources.[100] The effectiveness of Pennsylvania's regulatory mechanism suggested by Figure 1 may be underestimated because of the differences between site-level measurements for upstream facilities and inventory data. The impact of existing-source exemptions on total potential methane abatement in Pennsylvania is difficult to calculate with precision. As an example, if 50 percent of the mid-stream equipment in Pennsylvania (including pipelines, compressor stations and treatment plants) was exempt from the proposed GP-5 revisions, this could reduce methane abatement from existing sources by up to 30 percent, based on the abatement potential identified in Figure 1. Determining the impact of existing-source exemptions is also challenging because no public data source exists on current industry practices that may already mitigate methane emissions from existing sources.

# IV. Current and Potential Regulatory Approaches

This Section analyzes current and potential approaches to regulating methane emissions from unconventional oil and gas. Part A discusses possible approaches to regulating emissions and their challenges. Part B summarizes a number of voluntary initiatives to limit methane. Part C then reviews existing federal and state regulations and the approaches taken. States include Pennsylvania, Ohio, Texas, Colorado, West Virginia and California because they are either major producers of natural gas or early movers in regulating emissions of methane from unconventional oil and gas. The Section concludes by considering possibilities for regulatory innovation created by emerging science and technology.

Although the regulatory approaches described this section vary in their details, their approaches to technology-based regulation have fundamental similarities. To some extent, they all prescribe technology used by companies and require documentation of that use, and all have systems for assessing and addressing methane leaks. None uses atmospheric concentration data, or any direct measurements of emissions, to systematically quantify emission reductions in their

[99] Chandler E. Kemp, Arvind P. Ravikumar & Adam R. Brandt, *Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator*, 50(8) ENVIRON. SCI. TECHNOL. 4546 (2016).

[100] Based on technology requirements listed in Proposed GP 5 §§ A.9, A.12, K, L, O; and requirements listed in GP 5A §§ A.9, A.12, H, K, L, O.

regulatory approaches. California has begun, though, to employ satellite-based remote sensing and aircraft-based remote sensing in order to monitor and measure high emission methane "hot spots" as required under Assembly Bill 1496 (AB 1496).[101] More fundamentally, states vary in the scope of their coverage and the level of flexibility given to companies in their compliance approaches. This Section's final section compares state approaches and considers how emerging technology creates new regulatory opportunities to incorporate measurement.

### *A. Possible Approaches to Regulating Methane Emissions and Their Challenges*

Like many environmental regulations, current approaches to regulating methane emissions from unconventional oil and gas take the form of "technology-based regulation." Technology-based standards first emerged in the Clean Water Act in the 1970s and were incorporated into Clean Air Act regulation in the 1990s.[102] This regulatory approach often requires the use of "Best Available Technology" and focuses on point sources such as discharge from a pipe or emissions from a smokestack; it sometimes specifies what technology must be used.[103]

A foundational dilemma for approaches that mandate specific technology is the rapidly evolving nature of relevant technology. Because regulatory processes can take months or years to develop and implement, technology frequently has evolved by the time a regulation is in place. Best available technology requirements aim to solve that dilemma by allowing for a shift in technology used over time.[104]

Another regulatory approach to this dilemma, used especially in the European off-shore oil and gas context and mentioned as a model in the aftermath of the BP *Deepwater Horizon* oil spill, is one known as "safety case" regulation. In such an approach, the regulated industry comes up with its plan for maintaining safety at the required level rather than the regulation specifying how it does so. This approach can allow for flexibility in the face of evolving technology, as well as reduce costs, but requires monitoring to make sure the plan is both effective and being implemented as planned.[105]

As explored in the following sections, air emissions regulations of methane vary by state in what they cover and how prescriptive they are, with Pennsylvania's new regulatory framework providing wide coverage and a high level of prescription as compared to most of the other states. In the most prescriptive parts of the permits, companies must detail that they are using specific "best available technology" to prevent release of methane and employ particular approaches to leak detection. A key question raised by the improving capacity to monitor emissions is whether

[101] *Methane Hotspots Research (AB 1496),* CA AIR RES. BD. (AB 1496), https://ww2.arb.ca.gov/our-work/programs/methane/ab1496-research (last visited Aug. 27, 2018).

[102] Patricia R. McCubbin, *The Risk in Technology-Based Standards*, 16 DUKE ENVTL. L. & POL'Y F. 1 (2005).

[103] *See id.*; Jamison E. Colburn, *Technology Based? Cost Factoring in US Environmental Standards*, 7 MICH. J. ENVTL. & ADMIN. L. 84 ( 2017); Wendy E. Wagner, *The Triumph of Technology-Based Standards,* 2000 U. Ill. L. Review 83 (2000).

[104] For example, the Pennsylvania law on solid waste both specifies that permitting approaches have to be at least as stringent as best available technology and allows for industry to develop new technologies. PA GEN. ASSEMBLY, 1988 ACT 101, § 509, http://www.legis.state.pa.us/cfdocs/legis/LI/uconsCheck.cfm?txtType=HTM&yr=1988&sessInd=0&smthLwInd=0&act=101&chpt=5&sctn=9&subsctn=0.

[105] *See* NAT'L COMM'N ON THE BP *DEEPWATER HORIZON* OIL SPILL & OFFSHORE DRILLING, REPORT TO THE PRESIDENT, DEEP WATER: THE GULF OIL DISASTER AND THE FUTURE OF OFFSHORE DRILLING 252 (2011); Hari M. Osofsky, *Multidimensional Governance and the BP Deepwater Horizon Oil Spill*, 63 FLORIDA L. REV 1077, 1131-32 (2011).

evolving technology might allow for more flexibility for industry actions combined with monitoring to ensure industry is achieving targets to reduce methane emissions. Some of these approaches are being tested through voluntary methane reduction programs.

### *B. Voluntary Methane Reduction Programs*

There are a number of voluntary methane reduction programs that highlight potential approaches, including those established by the oil and gas industry, government, and interest groups.

#### 1. Voluntary Programs by Industry

On December 5, 2017, the American Petroleum Institute (API) announced an Environmental Partnership through which 26 oil and gas producers agreed to undertake measures to reduce emissions by finding and fixing leaks, replacing controllers, and reducing natural gas liquids escaping into the atmosphere.[106] The participating companies pledged to focus on reducing methane and VOC emissions starting on January 1, 2018.[107] Shell, Chevron, BP, Chesapeake Energy, ConocoPhillips, JKLM Energy, Penn Energy, Range Resources, Seneca Resources and XTO are among the more than 40 companies now participating in the program.[108] The Partnership has developed three separate Environmental Performance Programs for participating companies; these include (1) a leak program for natural gas and oil production sources; (2) a program to replace, remove, or retrofit high-bleed pneumatic controllers, and (3) a program for manual liquids unloading for natural gas production sources.[109] The companies pledge to deploy new technologies such as Method 21[110] or Optical Gas Imaging cameras to detect leaks.[111] Participants commit to replacing high-bleed pneumatic controllers with no or low-bleed pneumatic controllers and minimizing emissions associated with the removal of liquids that can build up and restrict natural gas flow as a well ages.[112] The Partnership also will provide a forum for industry partners to collaborate with different stakeholders.[113]

Similarly, the Climate and Clean Air Coalition (CCAC) Oil and Gas Methane Partnership is a more longstanding voluntary global initiative by the oil and gas industry to help reduce their methane

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106 As of July 16, 2018, the partnership has more than 40 members. *Natural Gas, Oil Industry Launch Environmental Partnership to Accelerate Reductions in Methane, VOCs*, API (Dec. 5, 2017), http://www.api.org/news-policy-and-issues/news/2017/12/04/natural-gas-oil-environmental-partnership-accelerate-reductions-methane-vocs; Devin Henry, *Oil Industry Group Launches Methane Reduction Program,* HILL (Dec. 5, 2017), http://thehill.com/policy/energy-environment/363315-oil-industry-group-launches-methane-reduction-program.

107 *Id.*

108 *Id.*

109 *Id.*

110 "Method 21 is an EPA method for determining VOC emissions from process equipment. The method is based on using a portable VOC monitoring instrument, such as an organic vapor analyzer." *EPA's Actions to Reduce Methane Emissions from the Oil and Natural Gas Industry: Final Rules and Draft Information Collection Request*, ENVTL. PROT. AGENCY., https://www.epa.gov/sites/production/files/2016-09/documents/nsps-overview-fs.pdf (last visited Aug. 8, 2018); *See* 40 CFR Part 60, Appendix A, Method 21.

111 *Leak Program*, THE ENVIRONMENTAL PARTNERSHIP, https://theenvironmentalpartnership.org/what-were-doing/leak-program/ (last visited Sept. 3, 2018).

112 *Pneumatic Controller Upgrades,* THE ENVIRONMENTAL PARTNERSHIP, https://theenvironmentalpartnership.org/what-were-doing/pneumatic-controllers-upgrades/ (last visited Sept. 3, 2018).

113 API, *supra* note 106.

emissions.[114] Initiated by the Climate and Clean Air Coalition at the UN Secretary General's Climate Summit in New York in September 2014,[115] its members include BP, Eni, Neptune Energy International SA, Pemex, PTT, Repsol, Shell, Statoil, and Total.[116] By becoming a partner, a member company undertakes to survey nine core sources,[117] evaluate cost-effective technology options to address uncontrolled sources, and submit an annual report on surveys, project evaluations and project implementation.[118] Each member company calculates methane emissions from nine core sources and reports its mitigation projects and the emissions reductions achieved to the Coalition Secretariat. The Secretariat then produces company-specific summary reports that are publicly available.[119]

Voluntary programs and regulations work in complementary ways and make important contributions to reducing emissions. Some industry leaders have recognized this need for complementarity. For example, on February 5, 2018, the President of ExxonMobil's natural gas subsidiary XTO publicly acknowledged that voluntary measures undertaken by the industry and augmented by "sound" government regulations are "key to helping drive improvements."[120] The company proposed a framework for such regulations.[121]

2. Voluntary Programs by EPA

EPA has launched several partnerships and programs over time with oil and gas companies to reduce methane emissions.[122] EPA's goal is to help industry partners reduce methane emissions, increase operational efficiency, and increase profits by capturing this valuable energy resource.[123]

In 1993, EPA adopted its first voluntary program called the Natural Gas STAR program. This program, which remains in existence, provides a framework for partner companies to implement technologies and practices to reduce methane emissions and document their voluntary emission reduction activities.[124] To participate in the program, a company must complete four steps: signing a memorandum of understanding with EPA; developing an implementation plan that specifies methane reduction technologies selected by the company; executing the implementation plan; and submitting an annual progress report.[125] The program provides numerous benefits to

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[114] *The CCAC Oil & Gas Methane Partnership*, Climate & Clean Air Coalition, http://www.ccacoalition.org/en/activity/ccac-oil-gas-methane-partnership (last visited Aug. 4, 2018).

[115] *Id.*

[116] *Id.*

[117] Under the partnership, the nine core emission sources of methane comprise natural gas driven pneumatic controllers and pumps, fugitive component and equipment leaks, centrifugal compressors with wet (oil) seals, reciprocating compressor rod seal/packing vents, glycol dehydrators, unstabilised hydrocarbon liquid storage tanks, well venting for liquids unloading, well venting/flaring during well completion for hydraulically fractured gas wells, and casinghead gas venting. *Id.*

[118] *Id.*

[119] *Id.*

[120] Sara Ortwein, *Methane Regulation: Stay Pragmatic and Seek the Possible*, ENERGY FACTOR (Feb. 5, 2017), https://energyfactor.exxonmobil.com/perspectives/methane-regulation-stay-pragmatic/.

[121] *Id.*

[122] *About EPA's Oil and Gas Methane Partnership*, Natural Gas STAR Program, ENVTL. PROT. AGENCY, https://www.epa.gov/natural-gas-star-program/about-epas-oil-and-gas-methane-partnerships (last visited Sept. 4, 2018).

[123] *Id.*

[124] *Id.*

[125] CLAYTAN MUNNINGS & ALAN KRUPNICK, COMPARING POLICIES TO REDUCE METHANE EMISSIONS IN THE NATURAL GAS SECTOR 4 (RFF Report: 2017), http://www.rff.org/files/document/file/RFF-Rpt-Methane.pdf.

participating companies, including information sharing and technology transfer, peer networking, creation of a voluntary record of reductions, and public recognition.[126]

In 2006, EPA initiated the Natural Gas STAR International Program (NGSI) to extend the scope of the domestic program to a global scale.[127] NGSI focuses on reducing methane emissions from oil and natural gas operations throughout the world.[128] The NGSI Program builds on the framework of the Global Methane Initiative (GMI), an international public-private partnership that advances cost-effective voluntary emission reductions.[129] Initiated in 2004, the GMI is the only international effort to specifically target methane emissions reduction and recovery on biogas, coal mines, and gas systems.

On March 30, 2016, EPA initiated the Methane Challenge Program with 41 founding partners.[130] The Methane Challenge provides a new mechanism where industry partners can make and track ambitious commitments to reduce methane emissions.[131] Companies choose between two options for adopting and implementing an emissions reduction commitment: a best management practices (BMP) commitment and a "ONE Future" emissions intensity commitment.[132] The BMP commitment obligates a company to implement certain BMPs specified by EPA at one or more emission sources.[133] The ONE Future option is a commitment to achieve a particular subsector-specific methane emissions rate on an aggregate basis for all sources the company owns within that subsector. This option builds on a preexisting industry effort called ONE Future.[134] Member companies pledge implementation within 5 years, along with transparently reporting their actions.[135]

### *C. Current Federal Approaches to Regulating Methane Emissions*

Federal approaches to regulating methane emissions from unconventional oil and gas are currently in flux. The Obama Administration developed a federal regulatory approach to methane emissions from oil and gas development, with both the EPA and BLM issuing final rules. However, those rules have been legally and legislatively challenged, and the Trump Administration is in the process of reconsidering them. This Section briefly explains the evolution of the federal approaches and their current status. Appendix I provides a more thorough discussion of the EPA and BLM Methane Rules together with the legislative, judicial, and administrative challenges to each Rule.

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[126] *Natural Gas STAR Program,* ENVTL. PROT, AGENCY, https://www.epa.gov/natural-gas-star-program/natural-gas-star-program (last visited Sept. 3, 2018).

[127] *See About EPA's Oil and Gas Methane Partnership, supra* note 122.

[128] *Id.*

[129] *Id.*

[130] *Id.*

[131] *Id.*

[132] *Methane Challenge Program*, Natural Gas Star Program, ENVTL. PROT. AGENCY, https://www.epa.gov/natural-gas-star-program/methane-challenge-program (last visited Sept. 3, 2018).

[133] *Id.*

[134] *Id.* ONE Future is a coalition of companies with operations across every part of the natural gas value chain that endorses a set of sector-specific intensity-based performance standards for methane emissions. *Id.*; *see* ONE FUTURE, http://www.onefuture.us (last visited Sept. 3, 2018). They aim to achieve an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total natural gas production. ONE Future is now a part of EPA's voluntary programs. *Id.*

[135] *See About EPA's Oil and Gas Methane Partnership, supra* note 122.

Under the Obama Administration, the 2013 Climate Action Plan outlined actions that would progressively reduce greenhouse gas emissions (GHG), including methane emissions, by 2020.[136] The Plan noted that a number of federal agencies would be working collaboratively to establish a comprehensive methane strategy and that agencies would be "assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions, and identifying existing authorities and incentive-based opportunities to reduce methane emissions."[137] Although the 2013 Climate Action Plan did not specifically mention the development of new regulations to reduce methane emissions, both the U.S. EPA and the U.S. Bureau of Land Management (BLM) pursued plans based on this Action Plan.[138]

On June 3, 2016, EPA published a Final Rule in the Federal Register entitled Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources.[139] This Final Rule is commonly referred to as the EPA Methane Rule. Later that year, on November 18, 2016, BLM published a Final Rule in the Federal Register entitled Waste Prevention, Production Subject to Royalties, and Resource Conservation.[140] This Final Rule is commonly referred to as the BLM Methane and Waste Prevention Rule. While these Final Rules have much substantive similarity, there are two important distinctions in their application. First, the EPA Methane Rule applies only to new and modified sources while the BLM Methane and Waste Prevention Rule applies to existing operations. Second, the EPA Methane Rule focuses exclusively on air quality while the BLM Methane and Waste Prevention Rule focuses primarily on waste reduction.

The EPA Methane Rule imposes standards for a number of different sources within oil and gas operations including centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, well completions, fugitive emissions, and equipment leaks at processing plants.[141] Because of its focus on waste prevention, the BLM Methane and Waste Prevention Rule places an emphasis on the limitation of flaring and venting. The BLM rule also imposes standards for leak detection and repair, pneumatic controllers and pumps, storage vessels, liquids unloading, and completion operations.[142]

Beginning shortly after their respective promulgation, each of these Final Rules has faced extensive challenges within the legislative, executive, and judicial branches of the federal government. Within the legislative branch, efforts were undertaken to invalidate both the EPA Methane Rule and the BLM Methane and Waste Prevention Rule using the Congressional Review Act process during the early days of the Trump Administration.[143] Both efforts, however, were unsuccessful. Additionally, legislation has advanced in the U.S. House of Representatives that would effectively invalidate the EPA Methane Rule by denying the appropriation of funds to EPA for the enforcement of the Rule.[144] This legislation also has not been enacted into law.

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[136] EXECUTIVE OFFICE OF THE PRESIDENT, THE PRESIDENT'S CLIMATE ACTION PLAN 6 (June 2013).

[137] *Id*. at 10.

[138] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35824 (June 3, 2016) (to be codified at 40 C.F.R. pt. 60) [hereinafter EPA Methane Rule].

[139] *See id.*

[140] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 83008 (Nov. 18, 2016) (to be codified at 40 C.F.R. pt. 3100, 3160, and 3170) [hereinafter BLM Methane Rule].

[141] EPA Methane Rule, *supra* note 138, at 35844.

[142] BLM Methane Rule, *supra* note 140.

[143] H.J. Res. 22, 114th Cong. (2015); H.J. Res. 36, 115th Cong. (2017).

[144] H.R. 3354, H.Amdt. 368, 115th Cong. (2017); H.R. 6147, H.Amdt. 908, 115th Cong. (2018).

In March 2017, President Trump issued an Executive Order on Promoting Energy Independence and Economic Growth.[145] This Executive Order has provided the basis for both EPA and BLM to initiate the process of reconsidering their respective Final Rules. On April 19, 2017, then EPA Administrator Scott Pruitt announced that EPA would reconsider the Methane Rule.[146] Subsequently, additional actions were taken by EPA to delay the implementation of the Methane Rule during the reconsideration process. As a result of litigation filed by several environmental groups, EPA has not been able to delay the implementation of the Methane Rule, but nevertheless, the agency is continuing to move forward with its plan to reconsider the Methane Rule. Most recently, on September 11, 2018, EPA released a proposed rule to reconsider three key elements of the EPA Methane Rule; this proposed rule would amend requirements pertaining to fugitive emissions requirements, pneumatic pump standards, and closed vent system requirements.[147] BLM also undertook actions to delay the implementation and pursue reconsideration of the Methane and Waste Prevention Rule. On February 22, 2018, the Department of the Interior published a Proposed Rule to replace the BLM Methane and Waste Prevention Rule.[148] In litigation challenging the BLM actions, a federal district court has upheld the ability of BLM to stay some provisions of the Methane and Waste Reduction Rule while it works to revise the rule.[149]

As a result of the extensive legislative, administrative, and judicial proceedings surrounding the EPA Methane Rule and the BLM Methane and Waste Prevention Rule, their future remains uncertain. The current federal uncertainty makes the varying state approaches to methane emissions regulation, which are the focus of the next Section, a critical component of the U.S. approach.

### *D. Current State Approaches to Regulating Methane Emissions*

States have taken varying approaches to regulating methane emissions from unconventional oil and gas production, and applicable state law continues to evolve. Appendix II provides a detailed discussion of the approaches taken by Pennsylvania, Texas, Colorado, California, Ohio and West Virginia. These states were chosen for review in this White Paper for several reasons. First, Texas and Pennsylvania are the two largest producers of natural gas, with Pennsylvania leading the country in unconventional oil and gas. Second, Pennsylvania was in the process of considering and implementing regulatory changes when this pilot project began and recently finalized its revised permits, which makes comparing its approach to that of other states timely. Third, Colorado promulgated the first in the nation regulations for methane emissions from unconventional oil and gas production and has served as a key example for other states. Fourth, California regulations often influence other jurisdictions, including the federal government, and are grounded in state legislation mandating greenhouse gas emissions reductions. Finally, West Virginia and Ohio offer examples of how other Appalachian Basin states have approached regulation of methane emissions from unconventional oil and gas development and production.

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[145] Office of the Press Secretary, Presidential Executive Order on Promoting Energy Independence and Economic Growth, (Mar. 28, 2017), *available at* https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1.

[146] News Release, Envtl. Prot. Agency, EPA to Reconsider Oil and Gas Rule, (April 19, 2017), https://www.epa.gov/newsreleases/epa-reconsider-oil-and-gas-rule.

[147] *Clean Air Council v. Pruitt,* 862 F. 3d 1 (D.C. Cir. 2017); Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration, 83 Fed. Reg. ___ (proposed Sep. 11, 2018).

[148] Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, 83 Fed. Reg. 7924 (proposed Feb. 22, 2018) (to be codified at 43 C.F.R. pt. 3160 and 3170).

[149] *Wyoming v. U.S. Dep't of the Interior*, 2:16-cv-00285-SWS (D. Wyo.) (Apr. 4, 2018).

The regulatory mechanisms and structures used by the states to regulate methane vary significantly. Pennsylvania, Ohio, and West Virginia, the three exemplar states in the Appalachian Basin, have the most similar regulatory structures – all three base their regulatory approaches to methane emissions from unconventional oil and gas in their state environmental agency's permitting processes. Pennsylvania's regulatory approach relies upon a permitting process that specifically addresses methane emissions from unconventional oil and gas established by its Department of Environmental Protection.[150] The Ohio Environmental Protection Agency's Division of Air Pollution Control is its key regulatory agency for methane emissions and established a new streamlined general permitting system with uniform standards targeting fugitive methane and volatile organic compound releases at critical stages along the natural gas value chain.[151] The West Virginia Department of Environmental Protection Division of Air Quality likewise addresses methane emissions through its permitting process.[152]

The other three states have quite different approaches. Texas includes methane as a regulated greenhouse gas under the Texas Clean Air Act,[153] and the Railroad Commission of Texas and Texas Commission on Environmental Quality are the key regulators there.[154] Colorado's 2014 initial rules and 2017 revision were adopted by the Colorado Air Quality Control Commission (CAQCC) under authority granted by the Colorado Air Pollution Prevention and Control Act.[155] California's methane emissions form part of California Air Resources Board regulations addressing greenhouse gas emissions from crude oil and natural gas facilities,[156] and state laws also require regulatory action by the California Public Utilities Commission[157] and the Division of Oil, Gas, and Geothermal Resources in the Department of Conservation.[158]

The approaches of these six states, as well as the evolving federal regulations, have foundational similarities in the way that they incorporate science and technology. Namely, they ground their requirements in the best available technology based in research available at the time of promulgation. They aim to have companies to use the best available technology and report on their use of such technology. However, there are some important differences among the states in what they cover and in how much flexibility they allow companies. To provide an example of this variation, Table 1 highlights some of the technology requirements in the approaches of Pennsylvania, California, and Colorado. Table 1 illustrates that Pennsylvania's new approach,

[150] Issuance of General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations or Remote Pigging Stations (BAQ-GPA/GP-5A); Modified General Plan Approval and/or General Operating Permit No.5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations (BAQ-GPA/GP-5), 48 Pa. B. 3491 (June 9, 2018).

[151] Ohio Rev. Code Ann. § 3704 (2017), Division of Air Pollution Control, *available at* http://www.epa.ohio.gov/dapc/dapcrules.aspx#112742676-effective-rules.

[152] 45 CSR § 14-2.80. d; 45 CSR § 14-7.1; 45 CSR § 14-7.3; 45 CSR § 14-7.5; 45 CSR § 14-8.1; 45 CSR §8.

[153] 5 Tex. Health and Safety Code Ann. § 382.

[154] 16 Tex. Admin. Code §§ 3.1, 3.30.

[155] COLO. REV. STAT. ANN. § 25-7-101 (West 2017).

[156] Final Regulation Order, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, CAL. CODE REGS. Title 17 §§ 95665-95677 (2017) [hereinafter Final Regulation Order].

[157] S.B. 1371 § 2, Reg. Sess. (Cal. 2014) (commencing with § 975(b)(2).

[158] S. 887 § 3, Reg. Sess. (Cal. 2016) (commencing with § 3180(d)(1).

though less prescriptive than originally proposed, contains prescriptive regulation in more areas than California and Colorado.[159]

Table 1. Prescriptive Methane Control Technology Comparisons for California, Colorado and Pennsylvania

| Technology Area | California | Colorado | Pennsylvania |
|---|---|---|---|
| LDAR for Wells | | X | X |
| Vapor Recovery Units or Other Vapor Control | X | | X |
| Compressors | X | X | X |
| LDAR for Processing Facilities | X | | X |
| High Bleed Devices | | X | |
| Reciprocating Compressor Rod Packing | X | | X |
| LDAR for Transmission Facilities | | | X |

Beyond differences in what they regulate, the six states also vary in the level of flexibility that they give to companies in meeting the requirements. Pennsylvania and Ohio tend to be the most specific and least flexible of the six states, whereas Texas is at the other end of the spectrum. Comparing the regulation of fugitive methane emissions from pipeline leaks in the recently adopted Pennsylvania permits versus the Texas regulations exemplifies this difference. Pennsylvania requires that operators address fugitive emissions with an LDAR program using "either an OGI camera, a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, or other leak detection methods approved by the Division of Source Testing and Monitoring."[160] Texas, in contrast, takes a less technologically specific approach, requiring that pipeline operators develop and submit a plan for detecting and repairing leaks.[161] Texas' regulations rely broadly on the use of Best Available Control Technologies but do not specify the exact technology that companies must use.[162] Colorado and Ohio regulations regarding methane emissions from natural gas storage provide another example of differences in level of prescriptiveness. Colorado, in a more flexible approach, requires operators of storage tanks to develop, certify and implement a Storage Task Emission Management System (STEM) plan to meet an "operate without venting" standard, which includes Approved Instrument Monitoring Method (AIMM) inspections.[163] In contrast, Ohio requires the use of a venting system that operates in a very specific manner.[164]

Although the six states' regulatory approaches vary in flexibility, they share in common the limited ways in which they monitor emissions. Leak detection uses local atmospheric measurement, but none of the states' regulatory approaches, with the exception to a limited extent of California, use atmospheric concentration data or direct measurement of emissions to assess whether the technology specifications achieve their goals. California is the only state studied that has deployed a statewide network of methane sensors. This lack of measurement makes it difficult to assess

[159] Pennsylvania's final General Permits 5 and 5A would establish a series of technology requirements for new unconventional natural gas operations, focused largely on those technologies that could reduce fugitive emissions and, in some cases, requiring Leak Detection and Repair (LDAR) systems. Final GP 5 §§ A.10, A.13, G, H, K; GP 5A §§ A.10, A.13, G, D, H, K.

[160] PA Final GP 5 § G.1(b)(ii).

[161] 30 Tex. Adm. Code § 8.206.

[162] 30 Tex. Adm. Code § 116.164.

[163] 5 COLO. CODE REGS. 1001-9: XVII. C.

[164] General Permit 19.1 Template, OHIO EPA, http://epa.ohio.gov/Portals/27/genpermit/GP19.1_TVF20170216.pdf (last visited Sept. 4, 2018).

accurately what emissions reductions have been achieved and constrains efforts to determine if regulations are achieving goals in a cost-effective manner.

Using atmospheric data and a "safety case" regulatory approach in which companies develop a plan for limiting methane emissions and verify its effectiveness through monitoring would be unique across all states (and, to our knowledge, internationally). Because no state has tried this approach, and the technology is emerging, core questions exist.

(1) Would an approach based on atmospheric data reduce methane emissions more effectively?

(2) Is developing a plan and then monitoring more cost-effective for companies than using specified approaches?

Our tentative conclusion, as detailed in Section V, is that systematic atmospheric monitoring of emissions rather than relying solely on inventories is likely to provide a fuller picture of how effective emissions reductions strategies are. If regulation incorporated this type of monitoring, it might be able to provide companies with greater flexibility in compliance because the effectiveness of each company's approach would be verifiable. However, as described in Sections III and V, current data gaps make a cost assessment of regulatory approaches challenging.

# V. Conclusions and Next Steps: Possibilities for Regulatory Incorporation of Emerging Science and Technology

Regulating methane emissions from unconventional oil and gas provides an important test case for the broader issue of how regulation can most effectively incorporate fast-moving science and technology. The key tension involves ensuring that regulation is prescriptive enough to assure that its goals are met while incorporating enough flexibility to allow for relevant science and technology to evolve and complementarity with emerging voluntary approaches. Although states vary in how much flexibility they give to companies, they have fundamental commonalities in how they measure methane emissions. With the exception of California, which has begun to incorporate some monitoring but not to the extent explored in this White Paper, states use inventory approaches to estimate emissions. With the exception of leak detection methods, none of these regulatory approaches incorporates atmospheric monitoring as a complement to inventory methods.

Based on our analysis of the science of measuring methane emissions and the economics of emissions abatement, we find two distinct ways in which emerging science and technology could potentially help make regulations in Pennsylvania and other jurisdictions more effective and efficient. First, as detailed in Section II, the discrepancies between emissions measured via inventories and emissions measured via atmospheric or site-level efforts need to be reconciled with respect to the key sources of methane emissions, including unconventional oil and gas. Substantial evidence exists supporting the hypothesis that large methane leaks from abnormal operations at a minority of production sites are the cause of this discrepancy, but more measurements are needed to verify or refute this hypothesis, and, more importantly, to understand the causes of these large leaks. Reconciling inventories and atmospheric measurements is important more generally because disagreements over baseline emissions levels (and which activities are contributing how much to emissions totals) make it difficult to measure verifiable emissions reductions and ensure that regulations provide the right abatement incentives. Second, if states hope to achieve meaningful greenhouse gas emissions reduction, regulatory approaches need to be more inclusive of multiple emissions sources and not focused solely on oil and gas activities.

With respect to methane emissions in particular, our assessment is that key emerging technologies for effective regulation are enhanced regional monitoring, continuing development of technology for wide-area and local monitoring, and leak detection and repair. Regional monitoring has the potential to allow regulators to assess levels of emissions and compliance more effectively than current inventory methods alone. It also may allow for regulation that is more flexible than the approaches taken by the states currently regulating in this area. The existing body of scientific research on methane emissions suggests that leak detection and repair is likely to be a very effective measure for reducing methane emissions. Technology for leak detection and repair is an area of active research and development. Regulatory approaches that encourage and can adapt to technological developments in this area would therefore be advantageous.

The ability to engage in wide-area measurement of emissions through either sensor networks or atmospheric monitoring (or both) could open the door to a more flexible and less prescriptive regulatory approach. Systematic atmospheric measurements could potentially help verify whether regulatory frameworks are actually reducing aggregate emissions. Atmospheric measurement could also potentially be used to reduce specific technology requirements; under such a system, measured deviations from an emissions threshold within some spatial boundary triggers a regulatory response. With well-designed regulatory responses, this kind of system could provide incentives for operators to install monitoring and leak detection equipment without the prescriptive technology mandates. However, research has not yet been done on this type of regulatory incorporation, and research, perhaps through regulatory pilots, is needed to see if it would be effective.

Atmospheric monitoring paired with current industry monitoring approaches potentially would allow changes in emissions to be identified in a more timely fashion. Atmospheric monitoring responds continuously to emissions, and could identify changes in emissions within days,[165] allowing for rapid responses due to failures (e.g., Aliso Canyon[166] in the Los Angeles basin), or testing the impact of best available technology and leak repair strategies within a few months. Inventory approaches remain slow and tedious, often provided annually with a significant lag time due to the collection of activity data (e.g., numbers of wells and compressor stations, length of pipelines, production data). Improvements could be made to inventories via more frequent updates of emissions factors. Activity data can be maintained with required public reporting from

[165] Thomas Lauvaux et al., *Urban Emissions of $CO_2$ from Davos, Switzerland: The First Real-Time Monitoring System Using an Atmospheric Inversion Technique,* 52 J. APPL. METEOROL. CLIMATOL. 2654 (2013), http://dx.doi.org/10.1175/JAMC-D-13-038.1.

[166] Stephen Conley et al., *Methane Emissions from the 2015 Aliso Canyon Blowout in Los Angeles, CA*, 351 SCIENCE 1317 (2016), doi:10.1126/science.aaf2348.

the industry.[167] Reevaluating the emissions factors, however, is much more time-consuming and challenging; in addition, emissions factors can change as technology evolves.[168]

Atmospheric monitoring would also encompass all sources of methane, therefore refining our current understanding of existing infrastructure, and enable data-driven regulatory approaches. Regional emissions, aggregated over many sources, could be targeted in a way that complements requirements for best available technology in certain sectors. Such an approach would require that regional maximum emissions targets are identified, and that monitoring methods are adopted. As with leak detection, technology for monitoring regional emissions is developing fairly rapidly. Regulatory frameworks that accommodate this evolving technology could help reduce emissions in an economically effective way. However, since no regulations taking such an approach currently exist for use as a model, careful evaluation of this approach and multi-stakeholder input on its design would be necessary.

Moreover, atmospheric monitoring technology continues to develop, which will only improve the capacity to measure emissions in a cost-effective manner. For example, the Tropospheric Monitoring Instrument (TROPOMI) on board the Copernicus Sentinel-5 Precursor satellite now measures methane every day at high resolution (7km) over the entire globe, potentially enabling leak detection and emission quantification over any region of the world.[169] Satellite monitoring will complement ground-based monitoring networks, and complement ground-based[170] and in-situ airborne[171] instruments that can be carefully calibrated and are likely to remain the backbone of future monitoring in ways that could assist regulatory systems.

While there are differences among states in the exact equipment requirements and in the breadth of those requirements across the natural gas value chain (e.g., how much grandfathering exists), if the regulations are appropriately constructed and enforced, methane emissions should decrease. However, the effectiveness of regulations and of the technology required under those regulations at actually reducing methane emissions can be evaluated only with more systematic monitoring. The cost-effectiveness of the regulations can also be measured more directly with more data from monitoring.

These technological developments in monitoring have significant implications for regulatory options in Pennsylvania in particular, one of the more technologically specific in its regulatory approach of the states studied. Currently, methane emissions from specific sources in Pennsylvania are rarely measured directly. Continuous emissions monitoring is not required under the General Permit revisions, with prescribed LDAR programs typically targeting identified leaks above a certain size.[172] The number of potential sources of above-ground methane emissions

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[167] ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSION AND SINKS: 1990-2013, ANNEX 3.6 (2015), *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2015.

[168] ENVTL. PROT. AGENCY, INVENTORY OF US GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1996. (1998), *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-1996.

[169] TROPOMI, http://www.tropomi.eu (last visited Sept. 4, 2018).

[170] Arlyn E. Andrews et al., *CO2, CO, And CH4 Measurements from Tall Towers in The NOAA Earth System Research Laboratory's Global Greenhouse Gas Reference Network: Instrumentation, Uncertainty Analysis, and Recommendations for Future High-Accuracy Greenhouse Gas Monitoring Efforts*, 7(2) ATMOS. MEAS. TECH. 647 (2014), doi:10.5194/amt-7-647-2014.

[171] Anna Karion et al., *Long-Term Greenhouse Gas Measurements from Aircraft*, 6(3) ATMOS. MEAS. TECH. 511 (2013), doi:10.5194/amt-6-511-2013.

[172] Final GP 5 § G; GP 5A § G.

from oil and gas operations in Pennsylvania is very large; continuous monitoring of individual sources would involve high costs with present technologies. Regional monitoring paired with improvements in available technologies for continuous monitoring of smaller emissions sources may open the door to regulatory approaches that are less prescriptive and more flexible, while achieving the same emissions reduction objectives, in Pennsylvania and other states that currently have or are developing regulation.[173]

The potential for this emerging monitoring technology to assist Pennsylvania in achieving environmental goals in a cost-effective manner suggests the importance of the types of partnerships that the Penn State Center for Energy Law and Policy aims to foster. As this example indicates, independent interdisciplinary research and constructive dialogue among key stakeholders about emerging science and technology can help inform regulatory options. With respect to methane emissions from unconventional oil and gas, Pennsylvania, as a leading producer of natural gas, has the opportunity to model this type of innovation. The multi-stakeholder working groups that have emerged from this pilot project have the potential to develop such models and move such innovation forward. We welcome the involvement of additional stakeholders in them.

[173] Anastasios Xepapadeas, *The Economics of Non-Point-Source Pollution*, 3(1) ANNU. REV. RESOUR. ECON. 355 (2011). For example, Virginia announced on September 12, 2018 that it plans to develop new regulations to address methane leaks from natural gas infrastructure and landfills. *Virginia to Establish Regulations Limiting Leaks of Methane*, AP NEWS, Sept. 12, 2018.

# Appendix I: Federal Regulation of Methane Emissions

This Appendix details the federal methane emissions rules promulgated during the Obama Administration, the legal and legislative challenges that they have faced, and their current status under the Trump Administration.

*A. EPA Methane Rule*

On August 18, 2015, EPA announced a series of proposed regulatory actions to reduce methane and volatile organic compound (VOC) emissions from the oil and natural gas industry.[174] The proposed actions addressed amendments to the 2012 New Source Performance Standards (NSPS) for the Oil and Natural Gas Industry[175] and included a Notice of Availability for draft control technique guidelines to assist states in ensuring best practices in reducing emissions.[176] EPA proposed to set new performance standards for methane and VOC emissions from new and modified sources not covered under the 2012 NSPS rules such as hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, and pneumatic pumps. EPA also proposed extending the new standards to natural gas production gathering and boosting stations, gas processing plants, and natural gas transmission compressor stations.[177]

On May 12, 2016, EPA announced three final rules regarding methane and volatile organic compounds (VOC) emissions from new, reconstructed and modified oil and gas sources, including from hydraulically fractured natural gas wells.[178] These three final rules included the EPA Methane Rule,[179] the Source Determination for Certain Emission Units in the Oil and Natural Gas Sector,[180] and the Federal Implementation Plan for EPA's Federal Indian Country Minor New Source Review program for oil and gas.[181]

The purpose of the EPA Methane Rule was to amend the 2012 New Source Performance Standards (NSPS) at subpart OOOO for the Oil and Natural Gas industry by setting out new standards for methane and VOC emissions.[182] More precisely, the EPA Methane Rule finalized GHG and VOC standards at subpart OOOOa and included new requirements for methane

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[174] *New Source Performance Standards and Permitting Requirements*, ENVTL. PROT. AGENCY, https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/new-source-performance-standards-and#Proposed (last visited Sept. 3, 2018).

[175] Oil and Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593 (proposed Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[176] Notice of Availability, 80 Fed. Reg. 56577 (Sept. 18, 2015).

[177] *See EPA's Actions to Reduce Methane and Volatile Organic Compound (VOC) Emissions from the Oil and Natural Gas Industry: Final Rules and Draft Information Collection Request Fact Sheet and Presentation*, ENVTL. PROT. AGENCY, https://www.epa.gov/stationary-sources-air-pollution/epas-actions-reduce-methane-and-volatile-organic-compound-voc (last visited Sept. 3, 2018).

[178] *See New Source Performance Standards and Permitting Requirements*, *supra* note 174.

[179] EPA Methane Rule, *supra* note 138.

[180] Source Determination for Certain Emission Units in the Oil and Natural Gas Sector, 81 Fed. Reg. 35622 (June 3, 2016) (to be codified at 40 C.F.R. pt. 51, 52, 70, and 71).

[181] Federal Implementation Plan for True Minor Sources in Indian Country in the Oil and Natural Gas Production and Natural Gas Processing Segments of the Oil and Natural Gas Sector; Amendments to the Federal Minor New Source Review Program in Indian Country to Address Requirements for True Minor Sources in the Oil and Natural Gas Sector, 81 Fed. Reg. 35944 (June 3, 2016) (to be codified in 40 C.F.R. pt. 49).

[182] EPA Methane Rule, *supra* note 138.

emissions.[183] In its Methane Rule, EPA aimed to establish standards based upon the Best System of Emission Reduction (BSER) and did not mandate a "particular technological system."[184]

The EPA Methane Rule, published with an effective date of August 2, 2016, imposes standards for a number of different sources within oil and gas operations including centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, well completions, fugitive emissions, and equipment leaks at processing plants. Except for those located at well sites, wet seal centrifugal compressors must be equipped with a system to achieve a 95 percent emission reduction. For reciprocating compressors, operators must change the rod packing at a prescribed frequency – either every 26,000 hours or 36 months – unless an alternative closed vent system is operated. Just as with the centrifugal compressor requirements, the requirements for reciprocating compressors do not apply at well sites. For pneumatic controllers, zero-bleed controllers are required at natural gas processing plants, and low-bleed controllers are required at all other locations.[185]

For pneumatic pumps, the EPA Methane Rule accommodates cost considerations by imposing a 95 percent emission reduction standard only upon those well sites where "either a control device or the ability to route to a process is already available online" and where it is technologically feasible to reach this standard. Where a control device is present, but cannot meet the 95 percent standard, the operator must maintain appropriate records demonstrating the equipment's capacity.[186]

The EPA Methane Rule requires the utilization of a reduced emissions completion process for most wells with combustion required for exploratory and delineation wells. Direct venting is prohibited except for specifically defined narrow exceptions. The Final Rule also requires the implementation of a leak detection and repair (LDAR) system with semiannual inspections at well sites and quarterly inspections at compressor stations. Monitoring of leaks within the LDAR program must be done using either optical gas imaging or Method 21, which is an EPA method for determining VOC emissions.[187]

*B. BLM Methane and Waste Prevention Rule*

On January 21, 2016, BLM released proposed regulations to address the venting, flaring, and leaking of natural gas during operations on Federal and Indian leases.[188] The Final BLM Methane and Waste Prevention Rule was published subsequently in the Federal Register on November 18, 2016, with a scheduled effective date of January 17, 2017.[189] According to the Press Release issued by the Department of the Interior upon the issuance of the Final Rule, the new rule aimed to "reduce the wasteful release of natural gas into the atmosphere from oil and gas operations on public and Indian lands."[190]

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183 EPA Methane Rule, *supra* note 138

184 *Id.* at 35829.

185 *Id.* at 35844.

186 *Id.*

187 *Id.* at 35846.

188 Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 6616 (Feb. 8, 2016) (to be codified at C.F.R. pt. 3160 and 3170)

189 BLM Methane Rule, *supra* note 140, at 83014.

190 Press Release, U.S Dept. of Interior, Interior Department Announces Final Rule to Reduce Methane Emissions & Wasted Gas on Public, Tribal Lands (Nov. 15, 2016), *available at*

Through this rule, BLM updated its over thirty-year-old regulations to bring them in line with new technology even though many of the operations subject to its Methane and Waste Prevention Rule also will be subject to the EPA Methane Rule. Its focus differs from the EPA Methane Rule in two key ways. First, it prioritizes waste reduction in contrast with the EPA Methane Rule, which primarily focuses on air quality. Although minimizing waste is the primary focus of the BLM Methane and Waste Prevention Rule, the standards imposed also accomplish environmental goals. The second key difference between the BLM and EPA Rules is that the BLM Rule applies to existing operations, not just to the new and modified sources regulated by the EPA Rule.

The BLM Methane and Waste Prevention Rule establishes requirements at stages of production where "waste-prevention actions are most effective and least costly."[191] As such, the Rule imposes standards for venting and flaring, leak detection and repair, pneumatic controllers and pumps, storage vessels, liquids unloading, and completion operations. While many of the BLM regulations mirror EPA standards, such as those governing well completions, there are some differences between the specific requirements contained within the two rules.

The BLM Methane and Waste Prevention Rule places great emphasis on limiting venting and flaring from natural gas facility operators. The Rule requires operators to capture much of the gas that would otherwise be vented or flared off—capture amounts are to be phased in during the years between 2018 and 2026 from 85 percent to 98 percent. The LDAR program uses an "instrument-based approach" that requires the use of optical gas imaging equipment or other approved devices. The frequency of inspections required under an LDAR program is consistent with the EPA Methane Rule – semi-annually at well sites and quarterly at compressor stations.[192]

For pneumatic controllers, operators are required to install low-bleed or no-bleed controllers within one year of the Final Rule's effective date. Additionally, pneumatic diaphragm pumps in operation for ninety or more days annually must be replaced with zero-emissions pumps or routing equipment installed unless the operator could demonstrate that doing so is cost prohibitive. Operators also must install routing equipment on storage vessels to capture tank vapors and "use available technologies and practices to minimize gas losses" during liquids unloading operations.

### C. *The Uncertain Future of the EPA and BLM Methane Rules*

Since their promulgation, both the EPA Methane Rule and the BLM Methane and Waste Prevention Rule have faced legislative challenges and lawsuits. Moreover, given EPA's current administrative review of the EPA Methane Rule and legal challenges to that review, it is unclear what portion of it, if any, will remain moving forward. This Section details those challenges and the current status of the regulations at the legislative, administrative, and judicial levels.

#### 1. <u>Legislative Review</u>

Although there have been legislative efforts to block these regulations, none of these bills have yet been passed by Congress. H.J. Res. 22 was introduced on January 6, 2017 to invalidate the EPA Methane Rule using the Congressional Review Act process. However, H.J. Res. 22 did not

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https://www.doi.gov/pressreleases/interior-department-announces-final-rule-reduce-methane-emissions-wasted-gas-public.

[191] BLM Methane Rule, *supra* note 140, at 83010.

[192] EPA Methane Rule, *supra* note 138, at 35846.

advance beyond the House Subcommittee on Environment. On January 30, 2017, a joint resolution – H.J. Res. 36 – was introduced, seeking to eliminate the BLM Methane and Waste Prevention Rule through the Congressional Review Act process. On February 3, 2017, the United States House of Representatives passed the measure by a vote of 221 to 191, but it failed to pass the Senate, which voted 49 to 51 on a procedural matter.[193] Additionally, there have been legislative efforts to prevent enforcement of the EPA Methane Rule through the denial of appropriations: on September 13, 2017, the U.S. House of Representatives voted in favor of an amendment to the appropriations bill that would prohibit the use of funds to enforce the EPA Methane Rule.[194] The amendment passed by a vote of 218 to 195,[195] but this provision was not included in the Omnibus FY 2018 Appropriations Bill enacted by Congress on March 23, 2018.[196] For FY 2019, the U.S. House of Representatives once again voted to include an amendment to the EPA appropriations bill that would deny funding to enforce the EPA Methane Rule.[197]

2. Administrative Review

Following the unsuccessful use of the Congressional Review Act, the Trump Administration is revisiting a number of the Obama Administration's environmental and energy rules, including the EPA Methane Rule and BLM Waste Prevention Rule pursuant to President Trump's Executive Order on Promoting Energy Independence and Economic Growth issued in March 2017.[198]

In August 2016, five industrial groups, including the American Petroleum Institute, Texas Oil and Gas Association, Independent Associations and GPA Midstream Association, submitted a petition to EPA requesting reconsideration of the EPA Methane Rule under the Clean Air Act, section 307(d)(7)(B).[199] In a letter dated April 18, 2017, then EPA Administrator Scott Pruitt addressed the industry petitioners by stating that "among the issues raised in the petitions that meet the requirements for reconsideration under CAA section 307(d)(7)(B) are objections regarding the provisions for requesting and receiving an alternate means of emission limitations and the inclusion of low-production wells."[200] Pruitt also added that "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."[201] On April 19, 2017, Pruitt announced that EPA would reconsider the EPA Methane Rule.[202]

[193] S. 516, 115th Cong. (2017).

[194] H.R. 3354, H.Amdt. 368, 115th Cong. (2017).

[195] *Id.*

[196] H.R. 1625, 115th Cong. (2018).

[197] H.R. 6147, H.Amdt. 908, 115th Cong (2018).

[198] Exec. Order No. 13,783, 81 Fed. Reg. 16093 (Mar. 28, 2017).

[199] Petition from Am. Petroleum Inst. to the Envtl. Prot. Agency, Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" (Aug. 2, 2016), *available at* http://www.api.org/~/media/Files/News/Letters-Comments/2016/160802-API-Petition-to-Reconsider-NSPS-OOOOa.pdf.

[200] U.S. Envtl. Prot. Agency, RE: Convening a Proceeding for Reconsideration of Final Rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources" published June 3, 2016, 81 Fed. Reg. 35824 (Apr. 18, 2017) (to be codified at 40 C.F.R. pt. 60).

[201] *Id.*

[202] News Release, Envtl. Prot. Agency, EPA to Reconsider Oil and Gas Rule (Apr. 19, 2017), *available at* https://www.epa.gov/newsreleases/epa-reconsider-oil-and-gas-rule.

On June 5, 2017, EPA issued a notice granting reconsideration and a partial stay of the Methane Rule for a period of three months.[203] EPA declared that it would reconsider the rule's requirements for fugitive emissions, certification of closed vent systems by professional engineers, and the well site pneumatic pump standards.[204] On June 16, 2017, EPA issued another notice proposing to stay certain requirements of the Methane Rule for a term of two years because "during this time, the EPA also plans to complete its reconsideration process for all remaining issues raised in these reconsideration petitions regarding fugitive emissions, pneumatic pumps, and certification by professional engineer requirements."[205] On the same day, EPA issued yet another notice proposing to stay certain requirements of the rule for three months.[206] EPA explained that "while EPA intends to complete that rulemaking and take final action before the initial three-month stay expires, there may potentially be a gap between the two stays due to the sixty-day delay in effectiveness of that action." Therefore, this second three-month stay would avoid such a gap.[207]

On March 12, 2018, EPA amended the EPA Methane Rule in response to comments the agency received on proposed stays of the rule and subsequent notices of data availability. EPA amended two narrow provisions of the requirements for the collection of fugitive components at well sites and compressor stations: (1) removal of the requirement for completion of delayed repair during unscheduled or emergency vent blowdowns, and (2) provision of separate monitoring requirements for well sites located on the Alaskan North Slope.[208] On September 11, 2018, EPA released a proposed rule that would amend requirements regarding fugitive emissions requirements, pneumatic pump standards, and closed vent system requirements.[209]

During this same period, the BLM Methane and Waste Prevention Rule was also under review. On February 22, 2018, the Department of the Interior published a rule in the Federal Register that would replace the 2016 BLM Methane and Waste Prevention Rule.[210] BLM said that "the proposed rule would eliminate duplicative regulatory requirements and re-establish long-standing requirements that the 2016 rule sought to replace."[211]

3. Judicial Review

Immediately after the promulgation of the BLM Methane and Waste Prevention Rule, a number of industry groups and affected states filed suit against the Department of the Interior. The cases

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203 U.S. Envtl. Prot. Agency, *supra* note 200.

204 *Id.*

205 Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements, 82 Fed. Reg. 27645 (proposed June 16, 2017) (to be codified at 40 C.F.R. pt. 60).

206 Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Three Month Stay of Certain Requirements, 82 Fed. Reg. 27641, (proposed June 16, 2017) (to be codified at 40 C.F.R. pt. 60).

207 *Id.*

208 Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Amendments, 83 Fed. Reg. 10628 (Mar. 12, 2018) (to be codified at 40 C.F.R. pt. 60).

209 *Clean Air Council v. Pruitt,* 862 F. 3d 1 (D.C. Cir. 2017); Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration, 83 Fed. Reg. ___ (proposed Sep. 11, 2018).

210 Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, 83 Fed. Reg. 7924 (proposed Feb. 22, 2018) (to be codified at 43 C.F.R. pt. 3160 and 43 C.F.R. pt. 3170).

211 BLM, BLM Offers Revision to Methane Waste Prevention Rule (Feb. 13, 2018), *available at* https://www.blm.gov/node/15338.

have been consolidated before the U.S. District Court for the District of Wyoming.[212] Due to this litigation, BLM published a notification postponing compliance dates for some requirements of the Methane and Waste Prevention Rule.[213] As a result of BLM's decision to postpone these compliance dates, a number of environmental groups filed suit against BLM seeking to enforce the original compliance dates.[214] On October 4, 2017, the U.S. District Court for the Northern District of California ruled that BLM was in violation of the Administrative Procedure Act (APA) by postponing the compliance dates for the Methane and Waste Prevention Rule after the Rule's effective date had already passed, and that the postponement amounted to a rulemaking that required compliance with the APA's notice and comment procedures. [215] The Court found that BLM's failure to consider the benefits of compliance with the provisions that were postponed rendered their action arbitrary and capricious.[216] Therefore, the Court reinstated the original deadlines for compliance with the Rule.[217]

On December 8, 2017, however, BLM announced that it had suspended or delayed certain requirements in the Methane and Waste Prevention Rule.[218] This action by BLM was to delay the effective date of the Rule until January 17, 2019.[219] BLM raised concerns regarding the statutory authority, cost, complexity, feasibility, and other implications of the Methane and Waste Prevention Rule, and said that the delay would provide time to review the Rule while avoiding compliance cost to industry that may turn out to be unnecessary.[220] BLM alleged that the delay did not substantially change the Methane and Waste Prevention Rule, but simply postponed implementation of the compliance requirements for certain provisions of the Rule for one year.[221] On December 19, 2017, California and New Mexico brought a suit against this 2017 Suspension Rule in the U.S. District Court for the Northern District of California.[222] Attorneys General for California and New Mexico asserted that the Suspension Rule was arbitrary and capricious as well as contrary to the BLM statutory mandate to prevent waste and ensure the safe and responsible development of oil and gas resources on public lands.[223] Similarly, on December 19, 2017, a coalition of environmental groups filed a lawsuit challenging the Suspension Rule.[224] The U.S. District Court for the Northern District of California granted the preliminary injunction enjoining enforcement of the Suspension Rule on February 22, 2018.[225]

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[212] *Wyoming v. U.S. Dep't of the Interior*, 2:16-cv-00285-SWS (D. Wyo.) (Apr. 4, 2018).

[213] Waste Prevention, Production Subject to Royalties, and Resource Conservation; Postponement of Certain Compliance Dates, 82 Fed. Reg. 27430 (proposed June 15, 2017) (to be codified at 43 C.F.R. pt. 3170).

[214] *California and New Mexico v. Zinke*, No. 3:17-CV-03804; *Sierra Club et al., v. Zinke,* No. 3:17-CV-03885 (N.D. Cal.) (Oct. 4, 2017).

[215] *Id.*

[216] *Id.*

[217] *Id.*

[218] Waste Prevention, Production Subject to Royalties, and Resource Conservation; Delay and Suspension of Certain Requirements, 82 Fed. Reg. 58050 (Dec. 8, 2017) (to be codified at 43 C.F.R. pt. 3160 and 43 C.F.R. pt. 3170). [hereinafter 2017 Final Delay Rule]; Press Release, Bureau of Land Mgmt., BLM Suspends or Delays Parts of Waste Prevention Rule (Dec. 7, 2017), *available at* https://www.blm.gov/node/14305.

[219] *Id.*

[220] See Press Release, Bureau of Land Mgmt., *supra* note 218.

[221] Final Delay Rule, *supra* note 218.

[222] *California and New Mexico v. BLM,* 3:17-cv-07186, (N.D. Cal.) (Dec.19, 2017).

[223] Press Release, State of Cal. Dept. of Justice, Attorney General Becerra Files Lawsuit against Trump Administration for Suspending Rule that Prevents Dangerous Waste of Natural Gas (Dec. 19, 2017), *available at* https://oag.ca.gov/news/press-releases/attorney-general-becerra-files-lawsuit-against-trump-administration-suspending.

[224] *Sierra Club et al. v. Zinke*, 3:17-cv-07187, (N.D. Cal.) (Dec. 19, 2017).

[225] *California and New Mexico v. BLM,* 3:17-cv-07187, (N.D. Cal.) (Feb. 22, 2018).

On April 4, 2018, the Wyoming District Court stayed certain provisions of the BLM Methane and Waste Prevention Rule opining that it "makes little sense" to force oil and gas companies to comply with the Rule when BLM has moved to suspend and revise it.[226] The Court ruled in favor of the Interior Department, blocking the petitioners' attempt to lift the Suspension Rule.[227] On April 30, 2018, the Court rejected a request from California, New Mexico, and the environmental groups that it reconsider this decision.[228] The Court said that the APA allows courts to "issue all necessary and appropriate process … to preserve status or rights pending conclusion of the review proceedings."[229] The Court concluded that, therefore, it was acceptable for the BLM Rule to be stayed in light of the Trump Administration's plans to rewrite it.[230]

In response to EPA's administrative stay of its Methane Rule, six environmental groups, including the Clean Air Council, Earthworks, Environmental Defense Fund, Environmental Integrity Project, Natural Resources Defense Council, and Sierra Club filed an Emergency Motion for a Stay on June 5, 2017, before the U.S. Court of Appeals for the District of Columbia Circuit seeking a judicial stay of EPA's initial three-month administrative stay of the Methane Rule.[231] The environmental groups claimed that such stay endangers the health of the entire community because of air pollution and that EPA had no authority to issue it pursuant to 42 U.S.C. §7607(d)(1)-(6).[232] On July 3, 2017, the D.C. Circuit Court vacated the initial three month stay of the Rule, holding that EPA lacked authority under the Clean Air Act to issue the stay.[233]

4. Conclusion

The future of the federal regulation of methane emissions from unconventional oil and gas is uncertain. Both the EPA Methane Rule and the BLM Methane and Waste Prevention Rule have faced, and continue to face, numerous challenges. The Trump Administration is reconsidering the BLM Methane and Waste Prevention Rule in an administrative review process.[234] Additionally, a federal district court has stayed the implementation of the BLM Methane and Waste Prevention Rule's "phase-in provisions" while the agency is reconsidering the Rule.[235] Similarly, while the EPA Methane Rule is in effect, EPA has been engaged in an administrative process to reconsider the Rule and has made amendments to portions of the Rule.[236]

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226 *Wyoming v. U.S. Dep't of the Interior*, 2:16-cv-00285-SWS, at 9, (D. Wyo.) (Apr. 4, 2018).

227 Adrian C. Hedden & Carslbad Current-Argus, *Federal Court Upholds Block on Venting and Flaring Rule*, CARLSBAD CURRENT ARGUS (Apr. 7, 2018), https://www.currentargus.com/story/news/local/2018/04/07/federal-court-upholds-block-venting-and-flaring-rule/491160002/.

228 Ellen M. Gilmer, *Wyo. Court will not reinstate BLM methane standards*, ENERGYWIRE (May 1, 2018), https://www.eenews.net/energywire/2018/05/01/stories/1060080495.

229 *Id.*

230 *Id.*

231 *Clean Air Council v. Pruitt,* 862 F. 3d 1 (D.C. Cir. 2017).

232 *Id.*

233 *Id.*

234 Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, 83 Fed. Reg. 7924 (proposed Feb. 22, 2018) (to be codified at 43 C.F.R. pt. 3160 and 43 C.F.R. pt. 3170).

235 *Wyoming v. U.S. Dep't of the Interior*, 2:16-cv-00285-SWS, at 9, (D. Wyo.) (Apr. 4, 2018).

236 Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Amendments, 83 Fed. Reg. 10628 (Mar. 12, 2018) (to be codified at 40 C.F.R. pt. 60).

# Appendix II: State Approaches to Regulating Methane Emissions from Unconventional Oil and Gas

This Appendix provides a detailed discussion of methane emissions regulation in Pennsylvania, Texas, Colorado, California, Ohio and West Virginia. As described in Section III.D, these are key comparator states in methane emissions regulation because of their large oil and gas production, innovative approaches to regulation, or location in the Appalachian Basin.

*A. Pennsylvania*

Since 2013, the Pennsylvania Department of Environmental Protection (DEP) has regulated methane emissions from unconventional oil and gas operations. Pennsylvania's regulatory approach has consisted of two components: (1) a General Permitting process for certain activities and (2) a Category 38 Exemption from the General Permitting process for other activities provided certain requirements are met. As of August 8, 2018, oil and gas operators in Pennsylvania must comply with a revised regulatory approach towards methane emissions that increases the types of oil and gas operations that must comply with the General Permitting process, revises the terms of the existing General Permit, and adds a new General Permit for unconventional oil and gas well pads. These 2018 revisions were implemented following a two-and-a-half year process of development that involved two separate comment periods and the promulgation of several drafts of the new and revised general permits. This Section details the background leading to this most recent set of revisions, including the 2013 General Permit requirements, 2016 revisions and the 2018 updates as well as the corresponding provisions of the Category 38 Exemption.

1. <u>2013 Regulatory Approach</u>

Like the revised 2018 regulatory approach, the earlier 2013 regulatory approach prescribed different procedures to address emissions from well pad operations in contrast to those from processing and compression operations. For well pad operations, which included completion activities and non-road engines, oil and gas operators generally were exempt from obtaining air quality permits under the Category No. 38 Exemption provided they met specified criteria.[237] Natural gas compression and processing operations, on the other hand, were required to apply for and obtain a General Permit 5 from DEP.[238]

a. <u>Air Quality Permit Exemption Category No. 38</u>

Pennsylvania's general environmental law provides that new sources of air pollution are required to prepare a plan and obtain approval for the plan from DEP unless subject to an exemption.[239] Certain sources, including those "sources and classes of sources determined to be of minor significance," are exempt from this requirement for plan approval.[240] One class determined by DEP to be of minor significance and therefore exempt from plan approval includes specified oil

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[237] PA DEPT. OF ENVTL. PROT., 275-2101-003, PLAN APPROVAL AND OPERATING PERMIT EXEMPTIONS (2013), pp. 8-11[hereinafter Category 38].

[238] PA DEPT. OF ENVTL. PROT., BAQ-GPA/GP-5, GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT (2013) [hereinafter GP 5].

[239] 25 PA. CODE § 127.

[240] 25 PA. CODE § 127.14(a)(8).

and gas exploration and production facilities and operations.[241] Prior to the 2018 revision, there were four types of activities encompassed by this so-called Category 38 Exemption: (1) conventional wells; (2) unconventional wells; (3) completion activities; and (4) non-road engines.[242]

Under the 2013 regulatory approach, operators of conventional wells were covered under the Category 38 Exemption without the need to comply with any additional requirements or to supply any documentation to DEP.[243] Operators of unconventional wells, however, were not covered by the Category 38 Exemption unless they complied with a number of requirements relating to leak detection and repair (LDAR), flaring, VOC emission controls, and NOx emissions.

For the LDAR program mandated by Category 38, specific technology was prescribed for the detection of leaks. Unconventional operators were required to establish an LDAR program that utilized an optical gas imaging camera, a gas leak detector meeting specified quality and accuracy standards, or another device approved by DEP.[244] This technology also must be used to determine that a repair had been successful.[245]

Unconventional operators were permitted to flare under the Category 38 Exemption, but the circumstances under which flaring could occur was limited.[246] When flaring was done on a permanent basis, the operator was required to use an enclosed combustion device.[247]

For VOC emissions, controls were required to ensure that all storage vessels and tanks maintained 95 percent or greater emission reductions.[248] Specific technology, however, was not mandated to maintain this level of VOC emissions. Operators were permitted to determine the amount of VOC emissions through any generally accepted method, including direct measurement, modeling, simulation, or calculation.[249] In addition to VOC requirements for storage vessels and tanks, the aggregate of all VOC emissions at the well site could not exceed a specified threshold on a rolling annual basis.[250] The aggregate NOx emissions from all stationary combustion engines also could not exceed a specified threshold on a rolling annual basis.[251]

To qualify for a permit exemption for completion activities, operators were required to comply with notice and record-keeping requirements and submit to DEP certain documents relating to flowback, venting, and combustion.[252] For non-road engines, operators were required to submit documentation showing that all engines were in compliance with emissions standards.[253]

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[241] Category 38, *supra* note 237, at 8-11
[242] *Id.*
[243] *Id.* at 8.
[244] *Id.* at 9.
[245] *Id.*
[246] *Id.* at 10-11.
[247] *Id.* at 10.
[248] *Id.*
[249] PA DEPT. OF ENVTL. PROT., Current Internal Implementation Instructions for Owners/Operators for Exemption No. 38 (Oct. 3, 2014), p. 5.
[250] Category 38, *supra* note 237, at 7.
[251] *Id.*
[252] Instructions, *supra* note 249, at 1-3.
[253] *Id.* at 3-4.

b. General Permit 5

The General Permit 5 (GP-5) process under the 2013 regulatory approach addressed natural gas compression and processing facilities that were not considered to be major sources under the federal Clean Air Act.[254] To qualify for GP-5, facilities could not exceed specified emission thresholds for certain pollutants, including Nitrogen Oxide, Carbon Monoxide, Sulfur Oxide, Particulate Matter, Hazardous Air Pollutants, and Volatile Organic Compounds, as measured on a rolling annual basis.[255]

Prior to the 2018 revision, GP-5 required that operators utilize Best Available Technology (BAT) in the operation of the compressor or processing facility.[256] Emission thresholds were established for various operations, including natural gas-spark ignition internal combustion engines, natural gas-fired simple cycle gas turbines, and glycol dehydrators.[257] Operators were required to utilize BAT to conduct operations so as to not exceed these established emission thresholds. GP-5 required operators to establish a leak detection and repair (LDAR) program that included monthly inspections using audible, visual, and olfactory (AVO) methods.[258] The LDAR program also was required to include the quarterly use of specific technology, namely a Forward Looking Infrared Camera (FLIR) or other device approved by DEP, to search for fugitive emissions.[259]

GP-5 contained various notification, reporting, and recordkeeping requirements. One such reporting requirement was the annual source report in which operators included emission data from all sources for the prior year.[260] GP-5 also mandated that operators complete a Compliance Certification form on an annual basis.[261] When submitting the Compliance Certification form, an operator was required to indicate whether the facility was in compliance with all terms on the GP-5 and the methods used to determine whether it was in compliance.[262]

[254] GP 5, *supra* note 238.
[255] GP 5 § A. 9(c).
[256] GP 5 § A. 5.
[257] GP 5 §§ B, C, and F.
[258] GP 5 § H. 1.
[259] GP 5 § H. 2.
[260] GP 5 § A. 15.
[261] GP 5 § A. 9(d).
[262] *Id.*

2. <u>Revisions to the Pennsylvania Regulatory Approach</u>[263]

On January 19, 2016, Pennsylvania Governor Tom Wolf issued a press release announcing the proposed implementation of a strategy by DEP for reducing methane emissions from the oil and gas industry.[264] The strategic approach on methane emissions was presented as being integral to the updated Pennsylvania Climate Change Plan, subsequently published by DEP in August 2016.[265] In the methane emissions strategy, DEP indicated its intention to revise the current GP-5 for natural gas compression and processing facilities as well as to replace the Category No. 38 Exemption for unconventional oil and gas development with a new general permit for oil and gas exploration, development, and production facilities.[266] On February 4, 2017, the Pennsylvania Bulletin included a notice of DEP's proposal to implement a new General Permit 5A (GP-5A) for unconventional natural gas well site operations and remote pigging stations (which play an important role ensuring pipelines are flowing smoothly), and to revise the existing GP-5 for application to natural gas compressions stations, processing plants, and transmission stations.[267] The notice provided for public comment through March 22, 2017; the public comment period was then extended through June 5, 2017.[268]

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[263] When the federal Clean Air Mercury Rule was invalidated by the D.C. Circuit Court, the Pennsylvania Supreme Court upheld that Pennsylvania could not maintain its own mercury regulations in *PPL Generation v. Commonwealth,* No. 7 MAP 2009 (PA. Dec. 23, 2009). However, APCA § 6.6(d) authorizes more stringent standards for hazardous air pollutant emissions from existing sources when needed to protect public health, welfare and the environment. Also, APCA § 6.6(a) applies only to HAPs and not to other regulations adopted under the APCA (David Mandelbaum, *Federal Environmental Deregulations and Pennsylvania Operations*, THE LEGAL INTELLIGENCER (Oct. 22, 2017), *available at* https://www.law.com/thelegalintelligencer/sites/thelegalintelligencer/2017/10/22/federal-environmental-deregulation-and-pennsylvania-operations/). The DEP's authority to issue general permits derive from Section 6.1(f) of the APCA, 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H (relating to general plan approvals and general operating permits). According to section 6.1(f) of the APCA, the Department may grant a general permit to any source category that can be adequately controlled using standardized specifications and conditions. Similarly, APCA § 6.6(c) provides that "the Department is authorized to require or control emissions of air pollutants, including hazardous air pollutants, by using the best available technology." 35 P.S. § 4006.6(c). Because general permits apply to new or modified air contamination sources, they establish BAT requirements and authorize the construction or modification of a source that meet the BAT requirements established under 25 Pa. Code §§ 127.1 and 127.12(a)(5). *See* PA Dept. of Envtl. Prot , COMMENT AND RESPONSE DOCUMENT FOR THE GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT FOR UNCONVENTIONAL NATURAL GAS WELL SITE OPERATIONS AND REMOTE PIGGING STATIONS (BAQ-GPA/GP-5A) AND THE REVISIONS TO THE GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT FOR NATURAL GAS COMPRESSOR STATIONS, PROCESSING PLANTS, AND TRANSMISSION STATIONS (BAQ-GPA/GP-5) AND THE REVISIONS TO THE AIR QUALITY PERMIT EXEMPTIONS (275-2101-003) (Part 1 of 2) 12 (June 2018).

[264] Press Release, Commonwealth of PA, Governor Wolf Announces New Methane Rules to Improve Air Quality, Reduce Industry Loss (Jan. 19, 2016), https://www.governor.pa.gov/governor-wolf-announces-new-methane-rules-to-improve-air-quality-reduce-industry-loss/.

[265] PA DEP, A Pennsylvania Framework of Actions for Methane Reductions from the Oil and Gas Sector (Jan. 19, 2016), p. 1.

[266] *Id.*

[267] Proposed General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations; Proposed Modifications to General Plan Approval and/or General Operating Permit No. 5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations (BAQ-GPA/GP-5); Proposed Modifications to the Air Quality Permit Exemption List (275- 2101-003), 47 Pa. Bulletin 733 (Feb. 4, 2017).

[268] Proposed General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations; Proposed Modifications to General Plan Approval and/or General Operating Permit No. 5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations (BAQ-GPA/GP-5); Proposed Modifications to the Air Quality Permit Exemption List (275- 2101-003); Extension of Public Comment Period, 47 Pa. Bulletin 1235 (Feb. 25, 2017).

a. Proposed General Permit 5A (Released on February 4, 2017)

Under the proposed GP-5A released on February 4, 2017, all operators of new or modified unconventional gas well sites and remote pigging stations were to obtain a general permit prior to construction of the facility.[269] Operators of new conventional well sites continued to be exempt from the permitting requirements under a newly defined Category 38b Exemption.[270] The proposed GP-5A encompassed emissions from a range of sources including fugitive particulate matter, well drilling and hydraulic fracturing operations, well completion operations, natural gas-fired combustion units, glycol dehydration units, stationary natural gas-fired spark ignition internal combustion engines, reciprocating compressors, storage vessels, tanker truck load-out operations, fugitive emissions components, controllers, pumps, enclosed flares and other emission control devices, pigging operations, and wellbore liquids unloading operations.[271]

The proposed GP-5A prescribed distinct compliance, notification, recordkeeping, and reporting requirements for each type of operation or emission sources covered by the general permit.[272] Depending upon the type of the individual operation or emission source, proposed GP-5A prescribed the use of specific technology, imposed a requirement to use best management practices, or established thresholds to be met by operators.

Under the proposed GP-5A, operators were required to institute a leak detection and repair (LDAR) program.[273] In some respects, the required LDAR program was similar to that required under the 2013 Exemption 38 process, but new requirements were to be added under proposed GP-5A. Operators were mandated to utilize specific technology to detect leaks – an OGI camera or other approved leak detection method.[274] In addition, operators were required to prepare a detailed fugitive emissions monitoring plan and conduct a monthly AVO inspection along with the quarterly LDAR program.[275]

Among other requirements pertaining to individual sources, the proposed GP-5A required that pneumatic controllers have a defined low-bleed rate.[276] Additionally, reciprocating compressors were to be replaced after a defined period of use unless emissions were captured through a closed vent system,[277] while pigging operations to clean out pipelines were to be accomplished in a manner that kept emissions below a specified threshold.[278]

269 PA DEPT. OF ENVTL. PROT., BAQ-GPA/GP-5A, GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT: UNCONVENTIONAL NATURAL GAS WELL SITE OPERATIONS AND REMOTE PIGGING STATIONS (proposed Feb. 4, 2017) [hereinafter GP 5-A], § A.6. A remote pigging station is "a facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compressor station, natural gas processing plant, or natural gas transmission station and which meet or exceed the exemption emissions thresholds of 200 tpy of methane, 2.7 tpy of total VOC, 0.5 tpy of a single HAP, or 1.0 tpy of total HAP." *Id.* at § A.3.

270 47 Pa. Bulletin 733 (Feb. 4, 2017).

271 GP- 5A § A.4.

272 GP 5-A §§ B-P.

273 GP 5-A § K.1.

274 GP 5-A § K.1(b).

275 *Id.*

276 GP 5-A § L.1(a).

277 GP 5-A § H.1.

278 GP 5-A § O.1.

The proposed GP-5A also contained various notification, reporting, and recordkeeping requirements pertaining to the overall operations. Operators were required to submit to DEP an annual emissions inventory from the prior year in addition to a Compliance Certification form.[279] The aggregate emissions from all sources at an unconventional well site or remote pigging station could not exceed specified levels for certain pollutants including Nitrogen Oxide, Carbon Monoxide, Sulfur Oxide, Particulate Matter, Volatile Organic Compounds, and Hazardous Air Pollutants, as measured on a rolling annual basis.[280]

b. Proposed Revised General Permit 5 (Released on February 4, 2017)

DEP released its proposed revision to GP-5 on February 4, 2017, which expanded the permit process to include transmission stations as well as compression and processing facilities.[281] As with the proposed GP-5A, the proposed revision to GP-5 prescribed distinct compliance, notification, recordkeeping, and reporting requirements for each of the types of operation or emission sources that were covered by the general permit.[282] Also in line with the proposed GP-5A permit, and depending upon the type of operation, the proposed revision to GP-5 imposed requirements that prescribed the use of specific technology, mandated the use of best management practices, or established thresholds to be met by operators. The sources encompassed by the Proposed Revised GP-5 included fugitive particulate matter, natural gas-fired combustion units, glycol dehydration units, stationary natural gas-fired spark ignition internal combustion engines, stationary natural gas-fired combustion turbines, reciprocating compressors, centrifugal compressors, storage vessels, tanker truck load-out operations, fugitive emissions components, controllers, enclosed flares and other emission control devices, and pigging operations.[283]

The Proposed Revised GP-5 continued to impose requirements mandating an LDAR program,[284] and added new requirements addressing pneumatic controllers[285] and pigging operations[286] in a manner similar to the requirements of Proposed GP-5A. The Proposed Revised GP-5 also continued to impose various notification, reporting, and recordkeeping requirements upon operators including the obligation to conduct an annual emissions inventory[287] and to obtain compliance certification on an annual basis.[288]

c. Draft Final General Permit 5, General Permit 5A, and Exemption 38 (Versions released on November 30, 2017, and March 30, 2018)

During the comment period following the release of the Proposed Revised General Permit 5 and the Proposed General Permit 5A, DEP received more than 10,500 comments. Following review of these comments, on November 30, 2017, DEP released Draft Final versions of General Permit 5,

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[279] GP 5-A §§ 9., 12.d.
[280] GP 5-A § 9.a.
[281] PA DEPT. OF ENVTL. PROT , BAQ-GPA/GP-5, GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT: NATURAL GAS COMPRESSION STATIONS, PROCESSING PLANTS, AND TRANSMISSION STATIONS (proposed Feb. 4, 2017) [hereinafter Proposed Revised GP 5], § A.4(a).
[282] Proposed Revised GP 5 §§ B-O.
[283] *Id*.
[284] Proposed Revised GP 5 § K.
[285] Proposed Revised GP 5 § L.
[286] Proposed Revised GP 5 § O.
[287] Proposed Revised GP 5 § A.12(d).
[288] Proposed Revised GP 5 § A.9.

General Permit 5A, and Exemption 38.[289] Subsequently, on March 30, 2018, DEP released additional Draft Final versions of General Permit 5, General Permit 5A, and Exemption 38. At that time, DEP also opened a 45-day public comment period, which ended on May 15, 2018.[290] According to DEP, these draft final revisions streamlined the requirements by referring to federal regulations for sources that do not differ from Pennsylvania's Best Available Technology (BAT) determinations and by removing redundant requirements.[291] Provisions for temporary sources were removed from GP-5A and placed under the revised Exemption 38.[292] BAT determinations for some sources were revised based on comments submitted to DEP. Other revisions to the general permits can be summarized as follows:

- Proposed notification requirements for construction of sources were replaced with a single notification for the commencement of operation, including construction completion date;

- The scheduled blowdown notification requirements were removed, and the malfunction reporting requirements were changed to be consistent with the GP-5 Malfunction Reporting Instructions;

- The annual report date was changed from March 1st to the anniversary date of the authorization to use the General Permits;

- A provision to allow the owner or operator to install or modify the source was added if the requirements of 25 Pa. Code §127.449 (a),(b), and (d) – (i) were met;

- The section pertaining to the fugitive particulate matter requirements was replaced with a citation to 25 Pa. Code §§ 123.1 and 123.2;

- For glycol dehydrators, daily recordkeeping requirements for throughput of natural gas and glycol circulation rate were removed;

- The requirement for installation of fuel flow meter for engines and turbines was removed;

- The recordkeeping requirement for entire tanker truck fleet used to collect liquid from a facility was removed; and

- The reporting requirements for tanker truck loadout operations, except for annual emissions inventory, was removed.[293]

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[289] *See* PA Dept. of Envtl. Prot., *A Pennsylvania Framework of Actions for Methane Reductions from the Oil and Gas Sector.*

[290] PA Dept. of Envtl. Prot., *DEP Seeks Public Comment on Draft Methane General Permits* (Mar. 30, 2018), http://www.media.pa.gov/Pages/DEP_details.aspx?newsid=978.

[291] *Id.*

[292] *Id.*

[293] Charles Boritz, *PA DEP, Overview of Revisions to the Proposed GP-5A and GP-5 and Emissions Discussion*, PA DEPT. OF ENVTL. PROT. (Feb. 14, 2018), http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/TechnicalAdvisoryBoard/2018/Feb14/GP-5%20GP-5A%20PowerPoint%20Presentation.pdf.

d. Final General Permit 5, General Permit 5A, and Exemption 38 (June 9, 2018)

After the second comment period expired, DEP released the final general permits and exemption criteria on June 9, 2018, with an effective date of August 8, 2018.[294] These final general permits require monthly audio, visual, and olfactory (AVO) inspections, and a quarterly LDAR program, although federal New Source Performance Standards (NSPS) require semiannual LDAR for well sites.[295] Control efficiency for methane, VOC, and HAP was revised from 98 to 95 percent.[296] Regarding fugitive particulate emissions, DEP removed the proposed Section B from the final general permits and replaced it with Section A, Condition 10(c)(iii) which cites 25 Pa. Code § 123.1 (prohibition of certain fugitive emissions/0 and §123.2 (fugitive particulate emissions).[297] According to 25 Pa. Code § 123.2, a person is not allowed to emit fugitive particulate matter into the atmosphere from a source specified in § 123.1(a) "if the emissions are visible at the point the emissions pass outside the person's property." Similarly, the requirement to install fuel flow meters was removed.[298] The ammonia slip was revised to 10 ppm/d in the final general permits as well as the Exemptions List, Category 38(c).[299] Pursuant to the final general permits, malfunctions that present imminent danger must be reported within one hour and malfunctions that do not create imminent danger must be reported within 24 hours.[300] The requirement to install electric controllers and electric pumps at facilities if grid power is available has been removed based on safety and reliability issues.[301] The visible emission surveys and the associated recordkeeping and reporting requirements have been removed.[302]

Through the process of developing the final general permits, Exemption 38 was amended to create three separate exemptions: Exemption 38(a), Exemption 38(b), and Exemption 38(c). Existing oil and gas production facilities are covered under either Exemption 38(a) or Exemption 38(b) unless they undergo a modification.[303] While Exemption 38(a) is applicable to oil and gas production facilities constructed prior to August 10, 2013, Exemption 38(b) applies to conventional oil and gas production facilities, and unconventional oil and gas production facilities meeting certain conditions, which were constructed between August 10, 2013 and August 7, 2018.[304] Exemption 38(c) is applicable to new or modified sources operating after August 8,

[294] Issuance of General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations or Remote Pigging Stations (BAQ-GPA/GP-5A); Modified General Plan Approval and/or General Operating Permit No.5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations (BAQ-GPA/GP-5), 48 Pa. B. 3491 (June 9, 2018).

[295] General Plan Approval and/or General Operating Permit BAQ-GPA/GP-5, Natural Gas Compression Stations, Processing Plants, and Transmission Stations (proposed Jun. 6, 2018) [hereinafter Final GP-5], § G; General Plan Approval and/or General Operating Permit BAQ-GPA/GP-5A, Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (proposed Jun. 6, 2018) [hereinafter Final GP-5A], § G, http://www.dep.pa.gov/Business/Air/Pages/Methane-Reduction-Strategy.aspx.

[296] *See* Final GP-5 §§ B.1(b), E.1(b), F.1(a)(iii), K.1(b); Final GP-5A §§ B.1(b), E.1(b), (c), F.1(b)(iii), K.1.(b).

[297] PA Dept. of Envtl. Prot., Comment and Response Document, *supra* note 263, Part 2, at 7.

[298] *Id.* Part 1, at 92

[299] *Id.* Part 2, at 7.

[300] Final GP-5 § A.6(d); Final GP-5A § A.6(d).

[301] PA Dept. of Envtl. Prot., *supra* note 263, Part 1, at 133, 135.

[302] *Id.* Part 1, at 92.

[303] Air Quality Permit Exemptions, 275-2101-003 (revised Aug. 8, 2018) [hereinafter Final Exemption 38], *available* at http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=19619&DocName=01%20AIR%20QUALITY%20PERMIT%20EXEMPTIONS.PDF%20%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e.

[304] Final Exemption 38, *supra* note 303, at 6.

2018, meeting certain qualifications.[305] Additionally, temporary activities such as site preparation, well drilling, hydraulic fracturing, completion, and work over activities were removed from GP-5A and placed under Exemption No. 38(c).[306]

3. Legislative Actions

Following the release of the DEP strategic approach, three Pennsylvania State Senators – Senator President Pro Tempore Joe Scarnati, Senate Majority Leader Jake Corman and Senator Gene Yaw, Majority Chair of the Senate Environmental Resources and Energy Committee – sent a letter to then acting, and now confirmed, Secretary of Environmental Protection Patrick McDonnell, dated February 6, 2017, asking a number of questions regarding the proposed revisions to the existing GP-5 permit and the new proposed GP-5A permit.[307] The Senators expressed concern that such changes would "[add] new degrees of complexity to the permitting and site construction process that may significantly impair the competitiveness of the Commonwealth and strongly discourage the investment of private capital into Pennsylvania." On February 24, 2017, Secretary McDonnell responded to the Senators' letter stating that "DEP believes that proposed GP-5A and the proposed revisions to GP-5 balance the needs of industry for cost-effective operation and the needs of the public for enhanced environmental protection."[308] As stated above, the final regulatory framework became effective on August 8, 2018.

*B. Texas*

Texas leads the nation in the production of natural gas, producing nearly double the amount of its nearest competitor, Pennsylvania – although Pennsylvania leads the country in shale gas production.[309] Institutionally, the Railroad Commission of Texas (RRC) is the chief regulatory organization for the oil and gas industry, including pipeline transporters, natural gas and hazardous liquid pipeline industry, natural gas utilities, the LP-gas industry, and coal and uranium surface mining operations.[310] The Texas Commission on Environmental Quality (TCEQ) also has a role as Texas' environmental agency. A memorandum of understanding between the RRC and the TCEQ explains their jurisdiction over various oil and gas activities.[311]

Although Texas generally does not directly regulate methane as an air pollutant, methane emissions are covered as a regulated greenhouse gas under the Texas Clean Air Act.[312] Texas law mandates that any operator constructing a new facility or modifying any existing facility contributing to air pollution obtain a permit prior to construction or modification.[313] Facilities which

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305 *Id.* at 9.

306 *See id.* at 6, 9.

307 *3 Senate Leaders Question Authority for DEP's Proposed Methane Emission Limits*, PA ENVIRONMENT DIGEST (Feb. 16, 2017), http://www.paenvironmentdigest.com/newsletter/default.asp?NewsletterArticleID=38798.

308 Letter from Patrick McDonnell, Acting Secretary of PA Dept. of Envtl. Prot. , to Senator Joe Scarnati, Senator Jake Corman and Senator Gene Yaw (Feb. 24, 2017), *available at* http://www.post-gazette.com/powersource/policy-powersource/2017/03/03/DEP-chief-defends-methane-rules-for-shale-gas-well-sites/stories/201703020080.

309 *Rankings: Natural Gas Marketed Production, 2016 (million cu ft)*, UNITED STATES ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/State/rankings/#/series/47 (last visited Sept. 3, 2018).

310 16 Tex. Admin. Code § 3.1.

311 16 Tex. Admin. Code § 3.30.

312 5 Tex. Health and Safety Code Ann. § 382.

313 30 Tex. Admin. Code § 116.

do not cause significant air contamination can be classified as de minimis by the TCEQ Executive Director who considers the facility's proximity to receptors of the contaminants, rate of emission of air contaminants, engineering judgment and experience, and whether adverse toxicological or health effects would occur off property.[314] Facilities classified as de minimis sources do not have to obtain an air authorization through the permitting process. Facilities that cannot meet a de minimis rule but will not make a significant contribution of air contaminants to the atmosphere may qualify for a Permit by Rule (PBR).[315] To qualify for a PBR, a number of general requirements must be met. Important to the question of methane emissions, greenhouse gas emissions of any amount do not qualify a facility for a PBR.[316] However, PBRs are appropriate for facilities producing not more than 25 tons per year of volatile organic compounds, which may incidentally affect methane emissions.

If a facility cannot meet the requirements for a PBR, then the applicant may qualify for a standard permit, which similarly does not include greenhouse gases as a qualifying air contaminant.[317] However, greenhouse gases are subject to Prevention of Significant Deterioration (PSD) review provided the facility is a new stationary source with the potential to emit 75,000 tpy carbon dioxide equivalent or is an existing stationary source that will have an emissions increase of 75,000 tpy carbon dioxide equivalent.[318] In this case, the facility will be subject to the incorporated Federal Prevention of Significant Deterioration of Air Quality guidelines.[319] Even if the facility is not subject to PSD review or the permitting guidelines for permits by rule or standard permits, the facility operator must maintain records sufficient to demonstrate the amount of greenhouse gas emissions do not require authorization under any other section.[320] Those records must be maintained for a minimum of five years from the date of construction or modification.[321]

Under Title 16 of the Texas Administrative Code, Texas controls natural gas releases with several regulations. For emissions at the well site, § 3.13 states that the well operator is responsible for regulatory compliance during all operations at the well and must effectively control the well at all times.[322] Venting at the well site during natural gas drilling and production is regulated under § 3.32 which allows only 24 hours of venting.[323] Venting beyond these limits would not constitute a legal use of gas under § 3.32. In many situations, §§ 3.13 and 3.32 are both utilized in the finding of violations. An operator's failure to maintain or repair well site equipment could constitute a violation of § 3.13 and consequently lead to an unauthorized venting in violation of § 3.32. These rules encourage the regular maintenance and upkeep of well site equipment.

More specifically, § 3.32 mandates that in most situations gas may legally be vented into the air for only twenty-four hours, after which time it must be flared off, which results in emissions of carbon dioxide, rather than the more potent methane that would be released were flaring not required. Further, gas released in this manner must be measured using a device conforming to standards established by the American Petroleum Institute and reported to the RRC under

[314] 30 Tex. Admin. Code § 116.119.
[315] 30 Tex. Admin. Code §106.
[316] *Id.*
[317] 30 Tex. Admin. Code § 116.610.
[318] 30 Tex. Admin. Code § 116.164.
[319] 40 C.F.R. § 51.166.
[320] 30 Tex. Admin. Code § 116.164.
[321] *Id.*
[322] 16 Tex. Admin. Code § 3.13.
[323] 16 Tex. Admin. Code § 3.32.

§3.27.[324] However, Texas includes a sizable list of gas releases that are exempt from §3.32 flaring requirements. Releases that are not readily measured by devices routinely used in industry operations are not required to be flared off. Also exempt from flaring requirements are vapors from storage tanks, gas released from the drilling operation itself and the stages of well completion following drilling, and fugitive emissions of gas (defined simply as releases that cannot reasonably be captured and sold or routed to a vent or flare).[325]

For pipelines used in the transport of natural gas, the RRC oversees a number of regulations applicable to concerns over the release of methane. Breaks or leaks allowing the escape of gas from any receptacle or pipeline must immediately be reported to the RRC by letter, detailing the location of the leak, specifying the quantity of gas released, and the measures being taken to remedy the situation.[326] The RRC also deals specifically with natural gas pipelines in §8. Gas companies must maintain written standard procedures for handling natural gas leak complaints.[327] Operators of gas distribution systems must create and have approved by the RRC leak survey programs that identify systems or segments of pipelines at the greatest risk of leaks, which will be inspected more frequently.[328] Leak surveys must be updated at least once every three years, or within thirty days following the addition of a new pipeline segment or system being put into operation, or if there has been a ten percent increase in the number of unrepaired leaks.[329] Natural gas pipeline leaks are classified under three categories, Grades 1-3, with Grade 1 being the most severe.[330] Each Grade has a different repair timeframe: Grade 1 leaks must be repaired "promptly," Grade 2 within thirty days, and Grade 3 within 36 months.[331]

TCEQ enforces strict controls on the release of volatile organic compounds in and around heavily populated areas; such controls may also reduce methane releases.[332] In a notable study conducted by TCEQ, infrared cameras were deployed to detect emissions or leakages of methane, ethane, and volatile organic compounds in fifty-eight Texas counties around oil and gas tanks, tank batteries, and compressor stations. The Monitoring Operations Program detected emissions at 75 percent of 150 sites monitored, and the Regional Field Operations Program detected emissions in 90 percent of 408 sites monitored.[333] TCEQ stressed that the infrared camera technology is a way to detect emissions and is currently incapable of quantifying detected emissions. While results vary dramatically based on a number of factors, the detectable minimum mass of hydrocarbons released, in pounds/hour, ranges from 0.001 to 0.22 lb/hr.[334]

After the infrared camera program, TCEQ followed up with twenty of the facilities that were analyzed to quantify the emissions detected and pursue voluntary actions to reduce them; response was minimal.[335] Where responses were sufficient and data supplied, estimates of

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[324] 16 Tex. Admin. Code § 3.27.
[325] *Id.*
[326] 16 Tex. Admin. Code § 3.20.
[327] 16 Tex. Admin. Code § 8.205.
[328] 16 Tex. Admin. Code § 8.206.
[329] *Id.*
[330] 16 Tex. Admin. Code § 8.207.
[331] *Id.*
[332] 30 Tex. Admin. Code § 115.
[333] *Barnett Shale: Technical Questions Answered*, TEXAS COMM'N ON ENVTL. QUALITY, https://www.tceq.texas.gov/airquality/barnettshale/bshale-faq (last visited Sept. 4, 2018).
[334] *Id.*
[335] *Id.*

emissions released indicated that most of the sites exceeded emission permit limitations.[336] The cooperating companies were able to reduce their emissions through either decreased production or repair/modification of operations.[337] No enforcement actions or penalties were issued as a result of TCEQ's infrared detection program, due to the cameras' inability to quantify the gas released. TCEQ does not require the use of infrared technology to detect leaks but does encourage innovative leak detection via its Voluntary Supplemental Leak Detection Program.[338]

Penalty guidelines to be imposed by the RRC in the event of non-compliance are designed to encourage voluntary corrective and future actions. The penalty guidelines, however, are not exhaustive; just because a certain violation is not listed does not mean the RRC cannot impose penalties. Similarly, the listed penalty amounts are simply typical starting points in assessing fines. A variety of factors are considered when the RRC determines a penalty: history of previous violations, seriousness of the violation, any hazard to the health or safety of the public, and the demonstrated good faith of the violator. Penalty enhancements are also available for certain violations like those that involve threatened or actual pollution, result in threatened or actual safety hazards, or result from reckless or intentional conduct of the violator. In fiscal year 2017, there were 44,578 alleged statewide rule violations with 1,309 of them being sent to the Office of General Counsel Enforcement.[339] In fiscal year 2016, there were 41,867 alleged statewide rule violations with 1,396 of them being sent to the Office of General Counsel Enforcement.[340] Penalty enhancements are also available for certain violators with a history of prior violations.[341] Penalties to be imposed by TCEQ include but are not limited to: "issuance of administrative orders with or without penalties; referrals to the Texas Attorney General's Office for civil judicial action; referrals to the Environmental Protection Agency for civil judicial or administrative action; referrals for criminal action; or permit, license, registration, or certificate revocation or suspension."[342]

### *C. Colorado*

In February 2014, the Colorado Air Quality Control Commission (CAQCC) adopted the first rules in the U.S. to directly regulate methane and volatile organic compounds (VOC) emissions from both new and existing oil and gas wells. These regulations were adopted to address ozone non-attainment areas. CAQCC derives its power to promulgate and enforce air quality regulation from the Colorado Air Pollution Prevention and Control Act.[343] Colorado's methane and VOC emission prevention initiative resulted from a negotiated effort to craft regulations between state regulators, the Environmental Defense Fund, and some of Colorado's biggest oil and gas companies (Anadarko Petroleum Corp., Noble Energy Inc., and Encana Corp.).[344] Other oil and gas

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[336] *Id.*

[337] *Id.*

[338] 30 Tex. Admin. Code § 101.

[339] *Report on Oil and Gas Field Operations' Violations and Enforcement, Fiscal Year 2017*, Enforcement Activities, R.R. COMM'N OF TX, http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/enforcement-activities/ (last visited Aug. 30, 2018).

[340] *Id.*

[341] 16 Tex. Admin. Code § 3.107.

[342] 30 Tex. Admin. Code § 70.5.

[343] COLO. REV. STAT. ANN. § 25-7-101 (West 2017).

[344] Cathy Proctor, *EPA Follows Colorado Lead in Targeting Methane Leaks from Oil & Gas*, DENVER BUSINESS JOURNAL (May 12, 2016), https://www.bizjournals.com/denver/blog/earth_to_power/2016/05/epa-follows-colorado-lead-in-targeting-methane.html?s=print. Jana Milford, *Out in Front? State and Federal Regulation of Air Pollution Emissions from Oil and Gas Production Activities in the Western United States*, 55 NAT. RESOURCES J. 1, 42 (2014), http://digitalrepository.unm.edu/cgi/viewcontent.cgi?article=1040&context=nrj.

entities objected to the proposed rules. In commenting on the adoption of these rules, Colorado Governor John Hickenlooper noted that "[t]he new rules approved by Colorado's Air Quality Control Commission, after taking input from varied and often conflicting interests, will ensure Colorado has the cleanest and safest oil and gas industry in the country and help preserve jobs."[345]

1. 2014 Regulations

In general, the 2014 regulations require oil and gas companies to find and fix methane leaks, manage their operations, and where necessary, install technology to limit or prevent methane and VOC emissions. These regulations apply to oil and gas exploration and production operations, well production facilities, natural gas compressors stations, and natural gas processing plants.[346] The rules apply to existing and new facilities.[347]

Specifically, the Commission's 2014 action revised or added language that affected three Colorado regulatory provisions: Regulation 3, 6, and 7.[348] The Commission's revisions to Regulations 3 and 6 were minor in comparison to revised Regulation 7. Regulation 6 was revised to fully adopt the federal New Source Performance Standard (NSPS),[349] which regulates emissions of volatile organic compounds from new, modified, or reconstructed gas wells, storage vessels, and other sources.[350] Regulation 3 was then revised to correspond with the NSPS permitting and reporting framework.[351] Sources subject to NSPS now require reporting and permitting only if they exceed 250 lb/year of emissions of non-criteria reportable pollutants.[352] Regulation Number 7 received the most serious revisions, which are covered in detail below. In general, the requirement to use air pollution control practices to minimize hydrocarbon emissions was expanded to include liquid collection, storage, processing, and handling operations.[353]

a. Storage tanks

Regulation 7 focuses on storage tanks at well sites and other locations. The Commission's revision requires storage tanks with uncontrolled actual VOC emissions greater than 6 tons per year (tpy) to control or capture hydrocarbon emissions by 95 percent, or by 98 percent if using a combustion device.[354] All tanks used during the first 90 days of production are required to control emissions by 95 percent. If a combustion device is used, it must have a design destruction efficiency of at least 98 percent.[355] In addition, well site operators must exercise best management practices to

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[345] Stephanie Paige Ogburn, *Colorado First State to Limit Methane Pollution from Oil and Gas Wells,* CLIMATE WIRE (Feb. 25, 2014), https://www.scientificamerican.com/article/colorado-first-state-to-limit-methane-pollution-from-oil-and-gas-wells/.

[346] Julie A. Rosen, *Should Colorado Methane Regulations Serve as Model for Federal Rules*, RYLEY CARLOCK & APPLEWHITE (Sept. 18, 2015), http://www.rcalaw.com/should-colorado-methane-regulations-serve-as-model-for-federal-rules.

[347] 5 COLO. CODE REGS. § 1001-9- XVII (2014)

[348] CO DEPT. OF PUB. HEALTH AND ENV'T, *Revisions to Colorado Air Quality Control Commission's Regulation Numbers 3,6, and 7, Fact Sheet*, (February 23, 2014), https://www.colorado.gov/pacific/sites/default/files/AP_Regulation-3-6-7-FactSheet.pdf.

[349] 5 COLO. CODE REGS. § 1001-8 (2018).

[350] 40 C.F.R. §§ 60.5360/5430 (2016).

[351] 5 COLO. CODE REGS. § 1001-5 (2017).

[352] *Id.*

[353] 5 COLO. CODE REGS. § 1001-9: XVII.B (2017).

[354] 5 COLO. CODE REGS. § 1001-9: XVII.C (2017).

[355] *Id*.

minimize hydrocarbon emissions during well maintenance and liquids unloading. The 2014 revision also requires that all valves, or pneumatic controllers, be retrofitted with "no-bleed" valves (where electric power is available) or "low-bleed" valves to minimize leaks. All storage tank operators must develop, certify and implement a Storage Task Emission Management System (STEM) plan to meet an "operate without venting" standard, which also includes Approved Instrument Monitoring Method (AIMM) inspections.[356] AIMM inspections require use of infrared cameras or other approved devices to detect leaks on either an annual, quarterly, or monthly basis.[357] Frequency of AIMM inspections is dictated by the amount of VOC emissions produced by the emission source—6 to 12 tpy requires annual inspections, 12 to 50 tpy requires quarterly, and greater than 50 tpy requires monthly inspections.[358]

b. <u>Compressor stations and well production facilities</u>

Regulation 7 also requires AIMM inspections of natural gas compressor stations and well production facilities.[359] Natural gas compressor stations must be inspected beginning January 1, 2015, with inspection frequency based on fugitive VOC emissions levels. Well production facilities constructed on or after October 15, 2014, must be inspected 15 to 30 days after the facility commences operation and thereafter in accordance with a schedule based on VOC emissions.[360] Well production facilities constructed before October 15, 2014, are to be phased-in to AIMM inspections over time based on the quantity of the facility's VOC emissions.[361] Regulation 7 distinguishes between well sites with storage tanks and sites without storage tanks.[362] Table 4 in Regulation 7 details required well production facility component inspections:

Table 4 - Well Production Facility Component Inspections[363]

| Well production facilities without storage tanks (tpy) | Well production facilities with storage tanks (tpy) | Approved Instrument Monitoring Method Inspection Frequency | AVO Inspection Frequency | Phase-In Schedule |
|---|---|---|---|---|
| > 0 and ≤ 6 | > 0 and ≤ 6 | One time | Monthly | January 1, 2016 |
| > 6 and ≤ 12 | > 6 and ≤ 12 | Annually | Monthly | January 1, 2016 |
| > 12 and ≤ 20 | > 12 and ≤ 50 | Quarterly | Monthly | January 1, 2015 |
| > 20 | > 50 | Monthly | | January 1, 2015 |

Monthly AIMM inspections are required for well production facilities without storage tanks when VOC emissions exceed 20 tpy, and for well production facilities with storage tanks when VOC emissions exceed 50 tpy.[364] Further, well production sites must be inspected monthly using audio, visual, and olfactory (AVO) means, unless the site is monitored monthly via AIMM methods.[365]

356 *Id.*
357 *Id.*
358 *Id.*
359 5 COLO. CODE REGS. § 1001-9: XVII.F (2017).
360 *Id.*
361 *Id.*
362 *See* COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, *supra* note 348, at 3.
363 5 COLO. CODE REGS. § 1001-9: XVII.F.4.c (2017).
364 5 COLO. CODE REGS. § 1001-9: XVII.F (2017).
365 *Id.*

### c. General leak detection

For leak detection and repair (LDAR), the Colorado provisions require owners or operators to inspect natural gas compressors stations and well production facilities for leaks. If leaks are detected at a level that meets the leak threshold, the regulations require leak repairs. Regulation 7 defines a leak detected with an infrared camera or AVO as any detectable emission. After a leak has been detected, the Commission requires that a first attempt to repair it be made within 5 days unless parts are unavailable, shutdown is required, or for other good cause. Re-monitoring is required within 15 days to determine if the well is still leaking. Further, Regulation 7 requires that operators keep and maintain leak detection and repair reports for two years, and make them available to the Commission on request. Operators are also required to submit annual LDAR reports by May 31.[366] The latest publicly available LDAR report, from 2015, showed that of the total number of component leaks identified (36,044), 98.5 percent were repaired.[367]

### d. Other requirements

In addition, there are several other technology-based requirements. For example, all combustion devices must use auto-igniters.[368] Combustion devices installed on or after May 1, 2014 must use auto-igniters upon completion, while combustion devices installed before May 1, 2014 must use auto-igniters starting May 1, 2016.[369] Beginning January 1, 2015, Regulation 7 required open-ended valves or lines to be sealed or become subject to leak detection and repair requirements (see above); in addition, centrifugal compressors had to reduce hydrocarbon emissions by 95 percent by that date.[370] Further, reciprocating compressors at natural gas compressor stations must replace rod packing every 26,000 hours of operation or every 36 months.[371] Well sites must now exercise best management practices to minimize hydrocarbon emissions during well maintenance and liquid unloading. They are required to capture or control gas emissions by 95 percent, or if a combustion device is used, by 98 percent. All valves or pneumatic controllers must be retrofitted with "no-bleed" valves (where electric power is available) or low bleed valves to minimize leaks.

## 2. 2017 Revisions to Regulation Number 7

On November 16, 2017, Colorado revised its Regulation Number 7 to comply with federal requirements and to improve ozone levels.[372] New revisions strengthened existing requirements. According to the Colorado Department of Public Health and Environment, the new revisions did the following:

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366 *Id.*

367 COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, LDAR ANNUAL REPORT (2015) SUMMARY (2016), https://www.colorado.gov/pacific/sites/default/files/AP_LDAR-AnnualReportsummary2015.pdf.

368 5 COLO. CODE REGS. § 1001-9: XVII.B (2017).

369 *Id.*

370 *Id.*

371 *Id.*

372 COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, COLORADO AIR QUALITY CONTROL COMMISSION'S 2017 REVISIONS TO REGULATION NUMBER 7 – OIL AND GAS EMISSIONS FACT SHEET (Dec. 20, 2017), https://environmentalrecords.colorado.gov/HPRMWebDrawer/RecordView/1113658.

- Expanded upon the existing requirement to reduce hydrocarbon emissions from wet seal centrifugal compressors by 95 percent in Section XVII.B.3.b. by adding monitoring and recordkeeping requirements;

- Expanded upon the existing rod packing replacement requirement in Section XVII.B.3.c. by applying it to reciprocating compressors at natural gas processing plants, adding the option to route emissions to a process, and adding monitoring and recordkeeping requirements;

- Required owners or operators to inspect combustion devices monthly;

- Beginning May 1, 2018, required natural gas-driven diaphragm pneumatic pumps located at a natural gas processing plant to have a VOC emission rate of zero and keep records of pumps; and required natural gas-driven diaphragm pneumatic pumps located at a well production facility to reduce VOC emissions by 95 percent if it is technically feasible to route emissions to an existing control devices or process;

- Expanded upon the existing LDAR requirements in Section XVII.F. by increasing the inspection frequencies for natural gas compressor stations and well production facilities with VOC emissions less than or equal to twelve tpy;

- Expanded upon the existing leak repair thresholds in Section XVII.F. by requiring repair of leaks detected with Method 21 at all-natural gas compressor stations if emissions exceed 500 ppm hydrocarbons;

- Expanded upon existing repair requirements in Section XVII.F. by adding the requirement that repair be completed within thirty days after discovery and within two years after discovery if shutdown is required;

- Expanded upon existing recordkeeping requirements in Section XVII.F. by adding the requirement that owners or operators also keep records of the type of repair method applied, records of the review by an owners or operators' representative for delay of repair due to unavailable parts, the date and duration of delay of repair, and the schedule for repairing a leak on delayed repair;

- Expanded upon existing reporting requirements in Section XVII.F. by adding the requirement that owners or operators include the records of the reviews related to delay of repair due to unavailable parts and to report the total number of facilities inspected, the total number of inspections, the total number of leaks requiring repair, the total number of leaks repaired, and the delayed repair list by inspection frequency tier;

- Expanded upon existing approved instrument monitoring method requirements in Section XVII.F. by specifying how to apply for a determination of an alternative approved instrument monitoring method;

- Required that continuous bleed, natural gas-driven pneumatic controllers at natural gas processing plants have a natural gas bleed rate of zero; and

- Required, beginning June 30, 2018, inspections of natural gas-driven pneumatic controllers to ensure proper operation. Where a pneumatic controller is not operating properly, owners or operators must take actions to return the pneumatic controller to proper operation. They must also keep records of inspection and response activities and submit an annual report concerning such activities.[373]

Overall, the revisions increased inspection frequency for combustion devices, natural gas compressor stations, and well production facilities; adopted a new inspection program for pneumatic controllers; and provided a mutual commitment with industry to further assess and analyze potential areas for cost-effective reduction in emissions.[374]

*D. California*

California's approach to regulating methane emissions from unconventional oil and gas is grounded in its broader greenhouse gas emissions standards for oil and gas. It also has passed specific laws on natural gas storage wells and leak abatement. Although California does not yet have extensive shale development, California regulations are relevant and implementable for any future shale development.[375]

In California, local air districts – including local air pollution control districts (APCD) and air quality management districts (AQMD) – have primary authority for issuing permits, monitoring new and modified sources of air pollutants, and ensuring compliance with national, state, and local emission standards.[376] The California Air Resources Board (ARB) does not have authority to issue permits directly for stationary sources of air pollution.

Any person with the intent to construct, modify, or operate a facility or equipment that may emit pollutants from a stationary source into the atmosphere must apply for an Authority to Construct permit from the appropriate local air district. Some projects may require a Prevention of Significant Deterioration (PSD) permit from the U.S. EPA or Title V Operating Permit for major facilities emitting air pollutants.

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[373] *Id.*

[374] Colorado Oil & Gas Association and Environmental Defense Fund, *Joint Statement on Air Quality Control Commission Vote on New Air Regulations,* ENVIRONMENTAL DEFENSE FUND (Nov. 16, 2017), https://www.edf.org/media/colorado-oil-gas-association-and-environmental-defense-fund-joint-statement-air-quality.

[375] Personal Communication to Ekrem Korkut from the California Air Resources Board (Jan. 13, 2017) (on file with authors); *see also* Chris Mooney, *Why It's Wrong to Use the California Drought to Attack Fracking*, WASHINGTON POST (Apr. 13, 2015), https://www.washingtonpost.com/news/energy-environment/wp/2015/04/13/what-environmentalists-get-wrong-when-they-use-the-california-drought-to-attack-fracking/?utm_term=.602b06ee6212.

[376] *See California Stationary Sources Permitting – Background*, CALIFORNIA AIR RESOURCES BOARD (Apr. 20, 2010), https://www.arb.ca.gov/permits/stationary-sources-overview.htm; *See also Local Air Districts (APCD or AQMD) Authority to Construct*, CALIFORNIA AIR RESOURCES BOARD (Apr. 20, 2010), https://www.arb.ca.gov/permits/airdisac.htm; *See also Air Districts (APCD or AQMD) Operating Permits*, CALIFORNIA AIR RESOURCES BOARD (Apr. 20, 2010), https://www.arb.ca.gov/permits/airdisop.htm.

1. Final Rule “Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities”

On March 23, 2017, the California Air Resources Board (ARB) adopted a final regulation addressing greenhouse gas (GHG) emissions from crude oil and natural gas facilities.[377] The new regulations address GHG emissions, including methane, produced by equipment and components found at facilities in the following sectors: onshore and offshore crude oil or natural gas production; crude oil, condensate and produced water separation and storage; natural gas underground storage; natural gas gathering and boosting stations; natural gas processing plants; and natural gas transmission compressor stations.[378] The objective of this final regulation was to provide GHG emissions standards as well as monitoring and control mechanisms for equipment and components listed below in order to reduce GHG and methane emissions. This final regulation did not provide for permitting requirements.

a. Separator and tank systems

The final regulation specifically addressed separator and tank systems reaching certain threshold values in terms of production capacity and water produced along with crude oil and condensate production.[379] As of January 1, 2018, the performance of a flash analysis testing is required for all existing and new separator and tank systems that do not use a vapor emission control system.[380] As of January 1, 2019, the use of vapor emission control systems is required for all existing and new separator and tank systems with an annual emission rate greater than 10 metric tons per year of methane.[381] In addition, owners/operators of separator and tank systems must perform a flash analysis testing if the annual emission rate is less than or equal to 10 metric tons per year of methane.[382]

b. Circulation tanks for well stimulation treatments

As of January 1, 2018, owners/operators of circulation tanks must develop and implement a Best Management Practices (BMP) Plan to reduce methane emissions and must submit such plan to the ARB Executive Officer.[383] As of January 1, 2019, owners/operators of circulation tanks must provide ARB with a report detailing the results of methane emission control from equipment at crude oil and natural gas facilities.[384] This report must contain a technology assessment and emissions testing relating to vapor collection and control equipment.[385] As of January 1, 2020, owners/operators of circulation tanks with at least 95 percent vapor collection and control efficiency must implement GHG and methane emission control measures unless the technology assessment states otherwise.[386]

[377] Final Regulation Order, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, CAL. CODE REGS. tit. 17 §§ 95665-95677 (2017) [hereinafter Final Regulation Order].
[378] *Id*. § 95666.
[379] *Id*. § 95668(a)(2).
[380] *Id*. §§ 95668(a)(3), (4).
[381] *Id*. §§ 95668(a)(6), (7).
[382] *Final Regulation Order*, *supra* note 377 § 95668(a)(8).
[383] *Id*. § 95668(b)(1).
[384] *Id*. § 95668(b)(2).
[385] *Id*. § 95668(b)(2)(A).
[386] *Id*. § 95668(b)(4).

### c. Reciprocating Natural Gas Compressors

The final regulation does not apply to natural gas compressors operating at less than 200 hours per calendar year.[387] As of January 1, 2018, owners/operators of reciprocating natural gas compressors are required to meet leak detection and repair requirements relating to specific components, including driver engines and compressors, and compressor rod packing or seal, and depending on whether the compressors are located at facilities in the sectors listed above.[388] As of January 1, 2019, vapor recovery control systems are required for compressor vent stacks used to vent rod packing or seal emissions.[389]

### d. Centrifugal Natural Gas Compressors

The final regulation does not apply to centrifugal natural gas compressors operating less than 200 hours per calendar year.[390] As of January 1, 2018, owners/operators of centrifugal natural gas compressors are required to follow leak detection and repair requirements as well as measure flow requirements relating to specific components, including components on driver engines and compressors using a wet or dry seal.[391] As of January 1, 2019, vapor recovery control systems are required for centrifugal compressors with wet seal.[392]

### e. Natural Gas Powered Pneumatic Devices and Pumps

As of January 1, 2018, owners/operators of intermittent bleed natural gas powered pneumatic devices are required to comply with leak detection and repair requirements when the device is idle and not controlling.[393] As of January 1, 2019, venting of natural gas to the atmosphere is prohibited from continuous bleed natural gas pneumatic devices and natural gas powered pneumatic pumps; owners/operators of such devices must meet leak detection and repair requirements.[394]

### f. Liquids Unloading of Natural Gas Wells

As of January 1, 2018, venting of natural gas into the atmosphere from wells must either implement a vapor recovery control system, estimate the volume of venting gas, or calculate the volume of venting gas using the Liquid Unloading Calculation or according to the ARB Mandatory Reporting of GHG Emissions and record the volume of venting gas and specify the method of calculation.[395]

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387 *Id*. § 95668(c)(2)(A).
388 *Final Regulation Order*, supra note 377, §§ 95668(c)(3), (4).
389 *Id*. § 95668(c)(4)(C).
390 *Id*. § 95668(d)(2).
391 *Id*. § 95668(d)(3).
392 *Id*. § 95668(d)(5).
393 *Final Regulation Order*, *supra* note 377, § 95668(e)(3).
394 *Id*. § 95668(e)(2).
395 *Id*. § 95668(f)(1).

g. Well Casing Vents

As of January 1, 2018, owners/operators of wells venting directly to the atmosphere must measure the rate of natural gas flow from the well using direct measurements.[396]

h. Natural Gas Underground Storage Facility Monitoring Requirements

As of January 1, 2018, owners/operators of underground storage facilities must develop and submit to ARB a monitoring plan.[397] The ARB must approve or disapprove the monitoring plan by July 1, 2018.[398] The final regulation requires owners/operators of such facilities to develop a leak detection protocol to be approved by the Department of Conservation Division of Oil, Gas, and Geothermal Resources until a monitoring plan is fully approved by ARB.[399] Once approval of the monitoring plan is granted, owners/operators of underground storage facilities must meet specific standards and procedures, including air monitoring to measure upwind and downwind ambient concentrations of methane, daily or continuous leak screening, and daily Optical Gas Imaging (OGI) in case of a well blowout.[400]

Furthermore, all components must be inspected and repaired within specific timeframes and the ARB Executive may perform inspections at facilities at any time to determine compliance.[401] Components, including hatches, pressure-relief valves, well casings, stuffing boxes, and pump seals should be monitored through visual and audio inspection within a timeframe based on the visit frequency reported by the facilities.[402] In addition, components should be tested for total hydrocarbon emissions, which must be measured in units of parts per million volume (ppmv) calibrated as methane.[403] Components with a leak concentration equaling or exceeding a certain threshold must be repaired or removed from service within a set timeframe.[404] Leaks should be identified using a weatherproof readily visible tag displaying the date and time of leak detection measurement and the measured leak concentration.[405]

One important point is that facility owners/operators applying for a local air district permit must comply with the above requirements provided in the final regulation.[406] In addition, facility owners/operators must register and report to ARB all equipment regulated under the final regulation no later than January 1, 2018, unless the local air district already established programs to collect the information identifying the equipment.[407]

2. Senate Bill No. 1371 – Natural Gas: Leakage Abatement

On September 21, 2014, Governor Jerry Brown signed into law Senate Bill No. 1371 addressing methane emissions from natural gas transmission and distribution pipelines in the State of

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396 *Id*. § 95668(g)(1).
397 *Id*. § 95668(h)(1).
398 *Id*. § 95668(h)(3).
399 *Final Regulation Order*, *supra* note 377, § 95668(h)(1).
400 *Id*. §95668(h)(5)(A)(B), (C).
401 *Id*. § 95669(c), (d).
402 *Id*. § 95669(e).
403 *Id*. § 95669(g).
404 *Final Regulation Order*, *supra* note 377, §§ 95669(h), (i).
405 *Id*. § 95669(j).
406 *Id*. § 95674(b)(1).
407 *Id*. § 95674(b)(2)(A).

California.[408] SB 1371 required the California Public Utilities Commission (PUC) to adopt and publish rules and procedures to reduce GHG and methane emissions to the maximum technologically feasible extent.[409] In addition, the bill provided for installation, inspection, maintenance, and repair requirements[410] and required the PUC to establish best management practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction.[411] Furthermore, all gas corporations operating pipeline facilities must file and submit a report to PUC including the following information: a summary of utility leak management practices, a list of new methane leaks in 2013 by grade, a list of open leaks that are being monitored or are scheduled to be repaired, and a best estimate of gas loss due to leaks.[412]

3. Senate Bill No. 887 – Natural Gas Storage Wells

On September 26, 2016, Governor Brown signed into law Senate Bill No. 887 addressing the maintenance and safety of natural gas storage wells as well as public transparency and disclosure on gas well storage operations.[413] This bill was designed to protect the people of California from methane emissions following the leakage incident at Aliso Canyon.[414]

The bill required the Division of Oil, Gas, and Geothermal Resources in the Department of Conservation to publish regulations establishing standards for gas storage facility wells along with leak detection and repair requirements.[415] In addition, the bill required a mechanical integrity testing for all gas storage wells as of January 1, 2018, including regular leak testing, casing wall thickness inspection, pressure test of the production casing, and any other additional well integrity testing.[416] The bill required operators of gas storage well facilities to prepare and maintain a comprehensive gas storage well training and mentoring program for their employees.[417]

SB 887 also provided that the ARB must develop a monitoring program, including continuous monitoring of the ambient concentration of natural gas, daily leak measurements and optical gas imaging in order to determine the presence of natural gas leaks and emissions into the atmosphere.[418] The ARB must also provide guidelines associated with the monitoring plan.[419] Furthermore, operators of gas well storage facilities must prepare and submit to ARB a facility monitoring plan and monitoring data.[420]

[408] Natural Gas: Leakage Abatement, S.B. 1371, Reg. Sess. (Cal. 2014).
[409] *Id*. § 2 (commencing with § 975(b)(2)).
[410] *Id*. § 2 (commencing with § 975(2)).
[411] *Id*. § 2 (commencing with § 975(e)(4).
[412] *Id*. § 2 (commencing with § 975(c)).
[413] Natural Gas Storage Wells, S.B. 887, Reg. Sess. (Cal. 2016).
[414] *Id*. § 1.
[415] *Id*. § 3 (commencing with § 3180(d)(1)).
[416] *Id*. § 3 (commencing with § 3180(b)).
[417] Natural Gas Storage Wells, S.B. 887, Reg. Sess. § 3 (Cal. 2016) (commencing with § 3186).
[418] *Id*. § 2 (commencing with § 42710(a)).
[419] *Id*. § 2 (commencing with § 42710(b)(1)).
[420] *Id*. § 2 (commencing with § 42710(b)(2)).

Inspection of the gas well storage facilities must be performed each year[421] and a risk assessment report is required each time a new underground gas storage facility is proposed.[422] This report is subject to peer review.[423]

4. California's Short-Lived Climate Pollutant Strategy (2017)

Senate Bill 605 (2014) of California required the California Air Resources Board (ARB) to develop a comprehensive Short-Lived Climate Pollution (SLCP) Strategy to reduce emissions of SLCPs.[424] SB 1383 set statewide emission reduction targets for methane, HFCs and black carbon and directed the Board to approve and begin the plan by January 1, 2018.[425] The SLCP Reduction Strategy was developed pursuant to SB 605 and SB 1383 and approved by the ARB on March 14, 2017. The Strategy defined short-lived climate pollutants (SLCPs) as "powerful climate forcers that remain in the atmosphere for a much shorter period of time [such as methane, fluorinate gases and black carbon] than longer-lived climate pollutants, such as carbon dioxide ($CO_2$)."[426]

The Strategy addressed a range of methane sources including fugitive emissions (leaks) from oil production, processing, and storage, gas pipeline system, or industrial operations.[427] The Strategy referred to ARB's ongoing efforts to develop methane regulations and to Senate Bill 1371 to reduce methane emission from oil and gas industry.[428] Senate Bill 1371 addressed methane emissions from natural gas transmission and distribution pipelines.[429] According to the Strategy, ARB and other California agencies are "funding research to identify high-methane 'hot-spot' emitters in the oil and natural gas sector and other sectors throughout California."[430]

*E. Ohio*

The Ohio Environmental Protection Agency's Division of Air Pollution Control develops and enforces rules in the Ohio Administrative Code regarding the state's oil and gas industry and its associated emissions.[431] In 2014, Ohio joined a small number of states beginning to tackle methane emissions from the growing hydraulic fracturing industry by setting new standards for operators at oil and gas well sites. In 2017, Ohio went a step further, extending similar regulations to natural gas compressor and transmission stations. Ohio's new regulations replaced its permitting process with streamlined general permits, which established uniform standards targeting fugitive methane and volatile organic compound releases at critical stages along the natural gas value chain.

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[421] *Id*. § 3 (commencing with § 3185).

[422] *Id*. § 5 (commencing with § 1103).

[423] Natural Gas Storage Wells, S.B. 887, Reg. Sess. § 5 (Cal. 2016) (commencing with § 1103(c)).

[424] Short-Lived Climate Pollutant, S.B. 605, Reg. Sess. (Cal. 2014).

[425] Reducing Short-Lived Climate Pollutants in California, CALIFORNIA AIR RESOURCES BOARD, https://www.arb.ca.gov/cc/shortlived/shortlived.htm (last reviewed May 3, 2018).

[426] *Id.*

[427] CALIFORNIA AIR RESOURCES BOARD, SHORT-LIVED POLLUTANT REDUCTION STRATEGY 7 (Mar. 2017), https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf.

[428] *Id.* at 9, 10.

[429] Natural Gas: Leakage Abatement, S.B. 1371, Reg. Sess. (Cal. 2014).

[430] STRATEGY, *supra* note 427, at 56.

[431] OHIO ENVTL. PROT. AGENCY, DIVISION OF AIR POLLUTION CONTROL, http://www.epa.ohio.gov/dapc/dapcrules.aspx#112742676-effective-rules (last visited Sept. 3, 2018).

Ohio leaves implementation details to the state's administrative agencies. In this manner, the Ohio Environmental Protection Agency (OEPA) is empowered through the Ohio Administrative Code to issue permits to the oil and gas industry.[432] Before streamlining the permitting process by instituting general permits, well site operators and upstream facilities had to meet Ohio's emission standards through extensive case-by-case permit reviews. The new general permits require all applicants to meet more stringent standards and agree to predefined terms. The major advances of the general permitting regime in regulating methane emissions derive largely from the promotion of early leak detection and repair and the fostering of industry accountability through recordkeeping, reporting, and transparency.[433]

General Permit 12.1 applies to oil and gas well site production operations, including hydraulically fractured horizontal wells and is designed to find and correct leaks of methane sooner and foster industry accountability. GP 12.1 targets fugitive methane emissions from any piece of well site equipment that could leak—valves, flanges, pressure relief devices, open end valves or lines, pump and compressor seals, connectors, vents, covers, and storage vessels.[434] To that end, GP 12.1 requires operators to scan the equipment at a well site on a quarterly basis using an infrared scanner or other device that can detect hydrocarbons. If, following one year of monitoring, less than two percent of the equipment is found to be leaking, then the frequency of the infrared monitoring can be reduced to semi-annual. Following two consecutive semi-annual periods with less than two percent equipment leakage, the frequency of monitoring can be reduced to annual. If during any one of the semi-annual or annual monitoring events, two percent or more of the equipment is found to be leaking, the frequency of monitoring is returned to quarterly. If there is an equipment leak, well site operators must make a first attempt to fix the leak within five days. Full repair of the leak must be completed no later than thirty calendar days after the leak is detected.

GP 12.1 also contains several provisions regarding reporting and recordkeeping procedures for operators of oil and gas wells. During infrared leak inspection, Ohio requires the following information be recorded: date of inspection, the name of the employee conducting the leak check, the identification of any component determined to be leaking, the date the first attempt to repair the component was made, the reason repair was delayed (where applicable), the date the component was repaired and determined no longer to be leaking, the total number of components leaking, and the percentage of components leaking. Further, the operator must maintain records demonstrating that the infrared camera is operated and maintained in accordance with the manufacturer's operation and maintenance instructions. These records must be maintained for at least five years and made available to the Director of OEPA upon request. Further, permittees are required to submit annual Permit Evaluation Reports to OEPA detailing the past year's inspections.[435]

In 2017, Ohio finalized general permits to address emissions at natural gas compressor stations. The standards established in Ohio's general permits 14-21 apply to several different types of equipment utilized in compressor stations. Similar to the regulations applicable to oil and natural gas well site operators, the general permits dealing with compressor stations require the use of infrared or other approved technology to find leaks anywhere such leaks could be found. The

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[432] Ohio Rev. Code Ann. §3704 (2017)

[433] Ohio Admin. Code 3745:31-29 (2017)

[434] General Permit 12.1, OHIO ENVTL. PROT. AGENCY, (2014), http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf.

[435] *Id.*

general permits require quarterly leak detection but have the same step-down timeframe as the well site permits – if leak detection is under two percent, monitoring requirements are reduced to semi-annually, then annually. Equipment associated with compressor stations are also included in the above general permits; natural gas fired and diesel engines, dehydrators, flares, and liquid storage tanks must be monitored for leaks. Compressor stations must also comply with the recording and reporting standards required of well site operators.[436]

*F. West Virginia*

The West Virginia Department of Environmental Protection (DEP) Division of Air Quality (DAQ) regulates and oversees air quality regulations in West Virginia. The State has incorporated 40 CFR 60, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015 and also incorporated 40 CFR Part 60 Subpart OOOO(a) – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced after September 18, 2015.

Major sources of air pollution are codified in West Virginia Rules at 45 CSR 14, which outlines "Permits for Construction and Major Modification of Major Stationary Sources for the Prevention of Significant Deterioration of Air Quality," commonly referred to as the "PSD rule." This rule establishes a preconstruction review process for new and modified sources. The pollutant Greenhouse Gases are regulated if:

- "the stationary source is a new major stationary source for a regulated NSR pollutant that is not a GHG and also will emit or will have the potential to emit 75,000 tpy $CO_2e$ or more; or
- the stationary source is an existing major stationary source for a regulated NSR pollutant that is not a GHG and also will have an emission increase of a regulated NSR pollutant, and an emission increase of 75,000 tpy $CO_2e$ or more."[437]

West Virginia forbids the construction, modification, or relocation of any major stationary source without notifying the Secretary and obtaining a permit to construct, modify or relocate.[438] Each permit application must be signed by the owner or operator, and such signature constitutes an agreement that the applicant assumes responsibility for the operation of the major stationary rules.[439] The Secretary must issue the permit unless the Secretary determines that the proposed major stationary source has not satisfied the requirements of this rule, will violate applicable emission standards, or will be inconsistent with the intent and purpose of this rule.[440]

Construction, relocation, or major modification of a major stationary source must meet each applicable emission limitation promulgated by the Secretary and any applicable emission standard under 40 CFR 60, 61 and 63, incorporated into West Virginia law in 45 CSR 16 and 45

[436] General Permits 14-21, OHIO ENVTL. PROT. AGENCY.
[437] W. Va. CODE R. § 45-14-2.80.d.
[438] *Id.* § 45-14-7.1.
[439] *Id.* § 45-14-7.3.
[440] *Id.* § 45-14-7.5.

CSR 34.[441] Similarly, West Virginia adopts and incorporates by reference national primary and secondary ambient air quality standards of the EPA under 40 CFR 50.[442] According to 45 CSR 16-3, no person may construct or operate a major stationary source in violation of provisions of 40 CFR 60.

Allowable emission increases from the proposed stationary source shall not cause or contribute to air pollution of:

- "any National or West Virginia Ambient Air Quality Standard in any air quality control region; or
- any applicable maximum allowable increase over the baseline concentration in any area."[443]

The Secretary may suspend, modify, or revoke the permit if the operator does not adhere to either the plans and specifications upon which the approval was based on or the conditions established in the permit.[444] Generally, records maintained and furnished by a registrant of a natural gas facility are evaluated and verified by the West Virginia DEP Secretary. While General Permit G70-D addresses the prevention and control of regulated pollutants from the operations of a natural gas production facility, General Permit G35-D addresses the prevention and control of regulated pollutants from the operation of a natural gas compressor and/or a dehydration facility. General Permit G33-A, on the other hand, allows registrants to install and operate spark ignition internal combustion engines greater than or equal to 25 HP and less than or equal to 500 HP meeting the certain requirements in the permit.

The DEP Secretary evaluates and verifies information and tests provided by a registrant about the emissions from a natural gas plant, compressor station and/or a dehydration facility. The registrant is required to furnish to the Secretary any information the Secretary may request to determine compliance with the General Permit.[445] Any authorized representative of the Secretary is allowed to visit the registrant's premises at all reasonable times to inspect any facilities, equipment, practices, or operations as well as to sample or monitor substances or parameters to determine compliance with the permit.[446]

The Secretary may suspend or revoke a General Permit if the plan and specification upon which the approval was based are not met.[447] Each violation of applicable permits may subject the registrant to civil and criminal penalties.[448] A registrant is required to conduct tests to determine compliance with emission limitations set forth in the Class II General Permit G70-D. The Secretary or his/her representative may witness or conduct such test. The Secretary may approve or specify

[441] *Id.* § 45-14-8.1.
[442] *Id.* § 45-14-8.
[443] W. Va. Code R. § 45-14-9.
[444] *Id.* § 45-14-19.2.
[445] General Permit G70-D § 2.14.1, W. Va. Dep't Envtl. Prot. (2016), https://dep.wv.gov/daq/permitting/Documents/G70-D%20Final%20Docs/G70-D%20Signed.pdf; General Permit G35-D § 2.14.1, W. Va. Dep't Envtl. Prot. (2017), https://dep.wv.gov/daq/permitting/Documents/G35-D%20Final%20Docs/G35-D%20General%20Permit%20Signed%20Version.pdf.
[446] G70-D, *supra* note 445, § 2.10.1.; G35-D, *supra* note 445, § 2.10.1.
[447] G70-D, *supra* note 445, § 2.9.1.; G35-D, *supra* note 445, § 2.9.1.
[448] G70-D, *supra* note 445, § 2.9. 3.; G35-D, *supra* note 445, § 2.9.3.

additional testing.[449] The registrant is required to keep records of all information at least 5 years following the date of each event.[450] The Secretary may ask the registrant to prepare and submit an emission inventory for the previous year.[451] The registrant of each natural gas production facility shall comply with 40 CFR Part 60, Subpart OOOO and Subpart OOOOa.[452] Any storage vessel containing condensate and/or produced water is to be monitored quarterly.[453] An owner or operator of an oil or natural gas facility must comply with the standards of Subpart OOOO(a) no later than August 2, 2016, or upon startup, whichever is later.[454]

[449] G70-D, *supra* note 445, § 3.4.; G35-D, *supra* note 445, § 3.4.
[450] G70-D, *supra* note 445, § 3.5.1.; G35-D, *supra* note 445, § 3.5.1.
[451] G70-D, *supra* note 445, § 3.6.4.; G35-D, *supra* note 445, § 3.6.4.
[452] G70-D, *supra* note 445, § 5.1.
[453] G70-D, *supra* note 445, § 6.2.1.2.; G35-D, *supra* note 445, § 5.2.1.2
[454] 40 C.F.R. § 60.5370a (2016).