Methane and Other Air Pollution Issues in Natural Gas Systems

Richard K. Lattanzio
Specialist in Environmental Policy

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Summary

Natural Gas Systems and Air Pollution

Congressional interest in U.S. energy policy has often focused on ways through which the United States could secure more economical, reliable, and cleaner fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing, directional drilling) used on unconventional resources (e.g., shale, tight sands, and coalbed methane) has made natural gas an increasingly significant component in the U.S. energy supply. This expansion, however, has prompted questions about the potential impacts of natural gas systems on human health and the environment, including impacts on air quality.

The natural gas supply chain contributes to air pollution in several ways, including (1) the leaking, venting, and combustion of natural gas in the course of production operations; and (2) the combustion of other fossil fuel resources or other emissions during associated operations. Emission sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, methane (i.e., the principal component of natural gas) and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—as well as nitrogen oxides, sulfur dioxide (SO_2), and various forms of hazardous air pollutants (HAPs).

Federal Air Standards for the Sector

Under the Obama Administration, the U.S. Environmental Protection Agency (EPA) promulgated air standards for several source categories in the crude oil and natural gas sector on August 16, 2012. These standards revise previously existing rules and promulgate new ones to regulate emissions of VOCs, SO_2, and HAPs from many production and processing activities that had never before been covered by federal standards (including, most notably, VOC controls on new hydraulically fractured natural gas wells). In an extension of these regulations, and in conjunction with the Obama Administration's Climate Action Plan, EPA promulgated additional rules on June 3, 2016, "to set standards for methane and VOC emissions from new and modified oil and gas production sources, and natural gas processing and transmission sources" not covered by the 2012 rule. Further, the U.S. Department of the Interior, Bureau of Land Management (BLM), promulgated a "Waste Prevention, Production Subject to Royalties, and Resource Conservation" rule on November 18, 2016, to target natural gas emissions on federal and Indian lands as a potential waste of public resources and loss of royalty revenue.

In a direct response to the Obama-era standards, and in line with his campaign promises, President Trump signed Executive Order 13783 on March 28, 2017. The order—entitled "Promoting Energy Independence and Economic Growth"—requires agencies to review existing regulations and "appropriately suspend, revise, or rescind those that unduly burden" domestic energy production and use. Section 7 of the order specifically directs the EPA Administrator and the Secretary of the Interior to review several regulations related to domestic oil and gas development, including EPA's 2016 methane standards and BLM's 2016 waste prevention rule. Both agencies have since proposed rulemakings to revise or rescind requirements of the rules. BLM finalized its revisions on September 28, 2018. EPA proposed its revisions on September 24, 2019.

Scope and Purpose of This Report

This report provides information on the natural gas industry and the types and sources of air pollutants in the sector. It examines the role of the federal government in regulating these emissions, including the provisions in the Clean Air Act and other statutes, and EPA's and other agencies' regulatory activities. It concludes with a brief discussion of a number of issues under debate, including

- defining the roles of industry and local, state, and federal governments;
- establishing comprehensive emissions data;
- determining the proper control of pollutants and sources;
- understanding the human health and environmental impacts of emissions; and
- estimating the costs of pollution abatement.

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Background

Congressional interest in U.S. energy policy has often focused on ways through which the United States could secure more economical, reliable, and cleaner fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing)[1] used on unconventional resources (e.g., shale, tight sands, and coalbed methane),[2] has made natural gas an increasingly significant component in the U.S. energy supply. While the practice of hydraulic fracturing is not new, relatively recent innovations have incorporated processes such as directional drilling, high-volume slick-water injection, and multistage fractures to get to previously unrecoverable resources. As a result, the United States has again become the largest producer of natural gas in the world.[3] The U.S. Energy Information Administration (EIA) projects natural gas to account for nearly 40% of total U.S. energy resource production by 2050, with shale gas and tight oil plays projected to grow.[4] In addition, some analysts believe that by significantly expanding the domestic gas supply, the exploitation of new unconventional resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions.[5]

Many in both the public and private sectors have advocated for the increased production and use of natural gas because the resource is domestically available, economically recoverable, and considered a potential "bridge" fuel to a less polluting and lower GHG-intensive economy. Natural gas is cleaner burning than other fossil fuels, emitting, on average, about half as much carbon dioxide (CO_2) as coal and one-quarter less than oil when consumed in a typical electric utility plant.[6] Further, natural gas combustion emits no mercury—a persistent, bioaccumulative neurotoxin—virtually no particulate matter or sulfur dioxide (SO_2), and less nitrogen oxides, per unit of combustion, than either coal or oil. For these reasons, pollution control measures in natural

[1] Hydraulic fracturing (hydrofracking, fracking, or fracing) is commonly defined as an oil or gas well completion process that directs pressurized fluids typically containing any combination of water, proppant, and any added chemicals to penetrate tight rock formations, such as shale or coal formations, in order to stimulate the oil or gas residing in the formation and that subsequently requires high-rate, extended flowback to expel fracture fluids and solids. The National Petroleum Council estimates that hydraulic fracturing will account for nearly 70% of natural gas development within the next decade. See National Petroleum Council, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," September 15, 2011, http://www.npc.org/NARD-ExecSummVol.pdf.

[2] These unconventional resources are commonly defined as follows: Tight sands gas is natural gas trapped in low permeability and nonporous sandstones. Shale gas is natural gas trapped in shale deposits, a very fine-grained sedimentary rock that is easily breakable into thin, parallel layers. Coalbed methane is natural gas trapped in coal seams. These resources are referred to as "unconventional" because, in the broadest sense, they are more difficult and/or less economical to extract than "conventional" natural gas, usually because the technology to reach them has not been developed fully or has been too expensive. For a more detailed discussion of these definitions, see the Natural Gas Supply Association's website, http://naturalgas.org/overview/resources/.

[3] The United States surpassed Russia as the world's leading producer of dry natural gas beginning in 2009. See U.S. Energy Information Administration (EIA), "International Overview," https://www.eia.gov/beta/international/.

[4] EIA, *Annual Energy Outlook, 2019*, https://www.eia.gov/outlooks/aeo/. Based on EIA reference case scenario.

[5] For more discussion on natural gas resources, see CRS Report R43636, *U.S. Shale Gas Development: Production, Infrastructure, and Market Issues*, by Michael Ratner.

[6] These values are averages based on CO_2 emitted per unit of energy generated. See EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106. Other pollutants derived from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 1, Stationary Point and Area Sources*, 1998, https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors.

gas systems have traditionally received less attention relative to those in other hydrocarbon industries. However, the recent increase in natural gas production, specifically from unconventional resources, has raised a new set of questions regarding environmental impacts. These questions centered initially on water quality issues, including the potential contamination of groundwater and surface water from hydraulic fracturing and related production activities. They have since incorporated other issues, such as water management practices (both consumption and discharge), land use changes, induced seismicity, and air pollution. These questions about hydraulic fracturing in unconventional reservoirs have led, in part, to the rise of various grassroots movements, some political opposition, and calls for additional regulatory actions, moratoria, and/or bans on the practice at the local, state, and federal levels.

Currently, the development of natural gas in the United States is regulated under a complex set of local, state, and federal laws that addresses many aspects of exploration, production, and distribution. State and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems. The organization of this oversight within each gas-producing jurisdiction varies considerably. In general, each state has one or more regulatory agencies that may permit wells—including their design, location, spacing, operation, and abandonment—and may regulate for environmental compliance. With respect to pollution controls, state laws may address many aspects of water management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety.

Furthermore, several federal statutes address pollution control measures in natural gas systems, and, where applicable, these controls are largely implemented by state and local authorities.[7] For example, the Clean Water Act regulates surface discharges of water associated with natural gas drilling and production as well as contaminated storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of wastewater from crude oil and natural gas production and the underground injection of fluids used in hydraulic fracturing if the fluids contain diesel fuel. The Clean Air Act (CAA) limits emissions from associated engines and gas processing equipment as well as some natural gas extraction, production, and processing activities.

Natural Gas Systems and Air Pollution

The Industry

Natural gas is a nonrenewable fossil fuel that is used both as an energy source (for heating, transportation, and electricity generation) and as a chemical feedstock (for such varied products as plastic, fertilizer, antifreeze, and fabrics). The natural gas that the nation uses—to heat homes and to fuel electric utilities—is the product of a long process beginning with the exploration and extraction of the resource and leading to its treatment in processing facilities, transportation to distributors, and eventual delivery through a long network of pipelines to consumers. Raw natural gas is commonly recovered from geologic formations in the ground through drilling and extraction activities by the oil and gas industry.[8] This industry includes operations in the production of crude oil and natural gas as well as the processing, transmission, and distribution of

[7] For more discussion, see CRS Report R43148, *An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions*, by Michael Ratner and Mary Tiemann.

[8] Natural gas can also be recovered as a byproduct from various other sources including mining, industrial, or agricultural processes. These secondary sources are not discussed in this report.

natural gas. For both operational and regulatory reasons, the industry is commonly separated into four major sectors: (1) crude oil and natural gas production, (2) natural gas processing,[9] (3) natural gas transmission and storage, and (4) natural gas distribution. This report uses these basic categories to track the various activities in natural gas systems, including the operations, emissions, and regulations discussed below. While the focus of this report is on the production sector, it also highlights air quality issues in other sectors, where appropriate.

The Resource

Raw natural gas is primarily a mixture of low molecular-weight hydrocarbon compounds that are gaseous in form at normal conditions. While the principal component of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as heavier hydrocarbons. These nonmethane hydrocarbons include types of VOCs, classified as ground-level ozone (i.e., smog) precursors, as well as, in some cases, hazardous (i.e., toxic) air pollutants (HAPs). Nonhydrocarbon gases—such as CO_2, helium, hydrogen sulfide (H_2S), nitrogen, and water vapor—may also be present in any proportion to the total hydrocarbon content. The chemical composition of raw natural gas varies greatly across resource reservoirs, and the gas may or may not be "associated" with crude oil resources. When natural gas is found to be primarily methane, it is referred to as "dry" or "pipeline quality" gas. When natural gas is found bearing higher percentages of heavier hydrocarbons, nonhydrocarbon gases, and/or water vapor, it is commonly referred to as "wet," "rich," or "hot" gas. Similarly, quantities of VOCs, HAPs, and H_2S can vary significantly depending upon the resource reservoir. VOC and HAP compositions typically account for only a small percentage of natural gas mixtures; however, this ratio increases the "wetter" the gas. Natural gas mixtures with a higher percentage of H_2S are generally referred to as "sour" or "acid" gas. These varying characteristics may cause both industry operations and regulatory oversight to differ across resource reservoirs.

Types of Emissions

Natural gas systems release air emissions in several different ways. This report categorizes these emissions into three types: *fugitive, combusted*, and *associated*.

1. **Fugitive** refers to the natural gas vapors that are released to the atmosphere during industry operations. Fugitive emissions can be either intentional (i.e., vented) or unintentional (i.e., leaked). Intentional emissions are releases that are designed specifically into the system: for example, emissions from vents or blow-downs used to guard against overpressuring or gas-driven equipment used to regulate pressure or store or transport the resource. Conversely, unintentional emissions are releases that result from uncontrolled leaks in the system: for example, emissions from routine wear, tear, and corrosion; improper installation or maintenance of equipment; or the overpressure of gases or liquids in the system. Fugitive emissions can contain several different kinds of air pollutants, including methane, VOCs, and HAPs.
2. **Combusted** refers to the byproducts that are formed from the burning of natural gas during industry operations. Combusted emissions are commonly released through either the flaring of natural gas for safety and health precautions[10] or the

[9] Petroleum refining (i.e., crude oil processing after the production phase) is classified as another industry sector for regulatory purposes and is not discussed in this report.

[10] Flaring is a means to eliminate natural gas that may be impracticable to use, capture, or transport. As with venting,

combustion of natural gas for process heat, power, and electricity in the system (e.g., for compressors and other machinery). The chemical process of combusting natural gas releases several different kinds of air pollutants, including CO_2, carbon monoxide (CO), nitrogen oxides (NO_x), and trace amounts of sulfur dioxide (SO_2) and particulate matter (PM).

3. **Associated** refers to secondary sources of emissions that arise from associated operations in natural gas systems. Associated emissions may result from the combustion of other fossil fuels (i.e., other than the natural gas stream) to power equipment, machinery, and transportation as well as the associated release of dust and PM from construction, operations, and road use. Associated emissions have the potential to contribute significantly to air pollution.[11]

The focus of this report is on fugitive and combusted natural gas emissions. Notwithstanding the additional emissions from associated sources, the primary focus of this report is on air quality issues related to the resource itself (i.e., the fugitive release of natural gas and its combustion during operations). It is this release of natural gas—and the pollutants contained within it—that makes air quality considerations in the crude oil and natural gas sector unique from other manufacturing-, construction-, and transportation-intensive sectors.

Sources of Emissions

Natural gas systems include many activities and pieces of equipment that have the potential to emit air pollutants.

- **Production sector (upstream).** Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation, and treating of oil and/or natural gas. Production operations span the initial well drilling, hydraulic fracturing, and well completion activities and include not only the "pads" where the wells are located but also the sites where oil, condensate, produced water, and gas from several wells may be separated, stored, and treated as well as the gathering pipelines, compressors, and related components that collect and transport the oil, gas, and other materials from the wells to the refineries or natural gas processing plants. Emissions of fugitive gas can be released both intentionally and unintentionally from many of these activities and pieces of equipment.

  Since production operations occur upstream from gas processing, any fugitive release of gas may include quantities of VOCs, H_2S, HAPs, and other pollutants at concentrations found within the reservoirs. Further, as some of these operations involve the initial removal of wastes and byproducts from the natural gas stream, the types and quantities of emissions may be dependent upon how the

the primary purpose of flaring is to act as a safety device to minimize explosive conditions. Gas may be flared at many points in the system; however, it is most common during the drilling and well completion phases, specifically at oil wells with associated gas. Compared to vented emissions, combustion is generally considered a better pollution control mechanism because the process serves to incinerate many of the VOCs and HAPs that would otherwise be released directly into the atmosphere.

[11] Air standards for various mobile and stationary source engines are covered in several parts of the *Code of Federal Regulations*, including 40 C.F.R. Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE) and 40 C.F.R. Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition (CI) ICEs as well as 40 C.F.R. Part 80, *et seq.*—Regulations of Fuels and Fuel Additives. For more information about standards for particulate matter, see CRS Report R40096, *2006 National Ambient Air Quality Standards (NAAQS) for Fine Particulate Matter (PM2.5): Designating Nonattainment Areas*, by Robert Esworthy.

wastes are managed (e.g., venting, flaring, separation, and storage). Historically, the greatest concern over air emissions from the production sector has focused on leaks from equipment and pipelines as well as combustion exhaust from compressor stations. Recently, however, concern has incorporated other activities such as drilling, hydraulic fracturing, well completions, and workovers.

- **Processing sector (midstream).** Processing operations are used to separate out the byproducts and wastes from raw natural gas in order to produce "pipeline quality" or "dry" natural gas for consumption. Due to the many and varied activities involved in these operations, natural gas processing plants have the potential to release significant quantities of air pollutants. These emissions result from the combustion of natural gas and other fossil fuels in compression engines as well as from the fugitive release of VOCs, SO_2, and HAPs from separators, dehydrators, and sweetening units used to extract byproducts and wastes from the natural gas stream.
- **Transmission, storage, and distribution sectors (downstream).** After processing, dry natural gas enters pipelines in the transmission, storage, and distribution sectors for delivery to utilities and consumers. Nationwide, natural gas systems consist of thousands of miles of pipe, including both mains and customer service lines, as well as compressors, storage facilities, and metering stations, which allow companies to both move and monitor the natural gas in the system. Due to the extensive network of pipelines, valves, pumps, and other components within the transmission, storage, and distribution sectors, fugitive releases of gas collectively can be a significant source of emissions. However, because these activities generally occur after processing, VOC, H_2S, and HAP content can be minimal, with methane remaining the primary component.

Pollutants

Air pollutants associated with natural gas systems include, most prominently, methane and VOCs—of which the crude oil and natural gas sector is one of the highest-emitting industrial sectors in the United States—as well as NO_x, SO_2, and various forms of HAPs.

- **Methane.** Methane—the principal component of natural gas—is both a precursor to ground-level ozone formation (i.e., "smog")[12] and a potent GHG,[13] albeit with a shorter climate-affecting time horizon than CO_2. Every process in natural gas systems has the potential to emit methane. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017* (released April 11, 2019) estimates 2017

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[12] While methane is a precursor to ground-level ozone formation, it is less reactive than other hydrocarbons. Thus, EPA has officially excluded it from the definition of VOCs. See EPA, *Conversion Factors for Hydrocarbon Emission Components*, July 2010, p. 2, https://19january2017snapshot.epa.gov/www3/otaq/models/nonrdmdl/nonrdmdl2005/420r05015.pdf.

[13] As a GHG, methane emitted into the atmosphere absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. According to the Intergovernmental Panel on Climate Change (IPCC) *Fifth Assessment Report 2013*, http://www.ipcc.ch/report/ar5/wg1/, in 2011, methane concentrations in the atmosphere exceeded preindustrial levels by 150%. Further, they contributed about 16% to global warming due to anthropogenic GHG sources, making methane the second-leading climate forcer after CO_2 globally. While the perturbation lifetime for methane is 12 years, CO_2's is considerably longer and does not undergo a simple decline over a single predictable timescale. For further discussion on climate change and its potential impacts, see CRS Report R45086, *Evolving Assessments of Human and Natural Contributions to Climate Change*, by Jane A. Leggett.

methane emissions from "Natural Gas Systems" (i.e., the natural gas supply chain) to be 6,624 gigagrams (Gg) (equivalent to 343.9 billion standard cubic feet [bscf], or 1.2% of the industry's marketed production that year).[14] In 2017, natural gas systems represented nearly 25% of the total methane emissions from all domestic sources and accounted for approximately 2.5% of all GHG emissions in the United States.[15] Natural gas systems are currently the second-largest contributor to U.S. anthropogenic (i.e., man-made) methane emissions.[16] Because of methane's effects on climate, EPA has found that it, along with five other well-mixed GHGs, endangers public health and welfare within the meaning of the CAA.[17]

- **VOCs—a ground-level ozone precursor.** The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20% of man-made VOC emissions nationwide (and representing almost 40% of VOC emissions released by stationary source categories).[18] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NO_x, and sunlight in the atmosphere contributes to the formation of ozone (i.e., smog). Ozone exposure is linked to several respiratory ailments.
- **NO_x—a ground-level precursor.** Significant amounts of NO_x are emitted at natural gas sites through the combustion of natural gas and other fossil fuels (e.g., diesel). This combustion occurs during several activities, including (1) the flaring of natural gas during drilling and well completions, (2) the combustion of natural gas to drive the compressors that move the product through the system, and (3) the combustion of fuels in engines, drills, heaters, boilers, and other production,

[14] EPA reported 2017 methane emissions from natural gas systems to be 6,624 Gg, equivalent to 165.6 million metric tons of CO_2 equivalent ($MMtCO_2e$). EPA reported 2017 methane emissions from all sources to be 656.3 $MMtCO_2e$ and 2017 GHG emissions from all sources to be 6,456.7 $MMtCO_2e$. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017*, EPA 430-R-19-001, April 11, 2019, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks. Here, as elsewhere in the report, GHGs are quantified using a unit measurement called CO_2 equivalent (CO_2e), wherein gases are indexed and aggregated against one unit of CO_2. This index is commonly referred to as the Global Warming Potential (GWP). The data in this report are based on EPA's 2019 inventory and the IPCC *Fourth Assessment Report 2007* wherein GWP values for methane are 25 and 72 over a 100-year and a 20-year time horizon, respectively. EIA reports 2017 U.S. natural gas marketed production to be 29,203.55 bscf. See https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm. CRS uses a conversion of 1 Gg = 0.051921 bscf. For more discussion of methane, see CRS In Focus IF10752, *Methane Emissions: A Primer*, by Richard K. Lattanzio.

[15] The end use combustion of natural gas (e.g., in the commercial, residential, transportation, or electric power generating sectors) emits GHGs, primarily in the form of CO_2, which is accounted for separately in EPA's inventory.

[16] Enteric fermentation is the largest contributor. Methane is produced as part of normal digestive processes in animals, particularly ruminant livestock (e.g., cattle). Microbes that reside in the animal's digestive system ferment food consumed by the animal and produce methane as a byproduct, which can be eructated (i.e., belching or flatulence) by the animal.

[17] EPA, "Endangerment and Cause or Contribute Findings for Greenhouse Gases," 74 *Federal Register* 66496-66516, December 15, 2009.

[18] EPA's 2014 National Emissions Inventory estimated VOC emissions from "oil and gas" stationary sources to be 3.23 million tons, from all stationary sources to be 8.26 million tons, and from all anthropogenic sources to be 16.48 million tons. Data for VOCs, as well as the other criteria pollutants and HAPs, are derived from EPA's National Emissions Inventory, https://www.epa.gov/sites/production/files/2017-04/documents/2014neiv1_profile_final_april182017.pdf.

construction, and transportation equipment.[19] In addition to its contribution to ozone formation, NO_x exposure is linked to several other respiratory ailments.

- **SO_2** is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas. SO_2 exposure is linked to several respiratory ailments.
- **Hazardous Air Pollutants (HAPs).** HAPs, also known as air toxics, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive diseases, or birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs in natural gas systems are n-hexane and the BTEX compounds (benzene, toluene, ethylbenzene, and xylenes). Further, some natural gas reservoirs may contain high levels of H_2S.[20] HAPs are found primarily in natural gas itself and are emitted from equipment leaks and from various processing, compressing, transmission, distribution, or storage operations. They are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

The Federal Role

Several federal agencies have authorities to set standards on the natural gas industry that could have the effect of controlling air emissions. This report summarizes some of the more significant actions taken by EPA, the U.S. Department of the Interior's Bureau of Land Management (BLM), and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).

EPA and the Clean Air Act

The CAA[21] seeks to protect human health and the environment from emissions that pollute ambient, or outdoor, air.[22] It requires EPA to establish minimum national standards for air emissions from various source categories (e.g., EPA has listed "Crude Oil and Natural Gas Production" and "Natural Gas Transmission and Storage" as source categories) and assigns primary responsibility to the states to assure compliance with the standards. EPA has largely delegated day-to-day responsibility for CAA implementation to the states, including permitting, monitoring, inspections, and enforcement. In many cases, states have further delegated program implementation to local governments. Sections of the CAA that are most relevant to air quality issues in natural gas systems are outlined in the following sections.

[19] NO_x emissions from engines and turbines are covered by 40 C.F.R. Section 60, Subparts JJJJ and KKKK, respectively.

[20] Hydrogen sulfide was on the original list of hazardous air pollutants in the CAA, Section 112(b), but was subsequently removed by Congress. Currently, hydrogen sulfide is regulated under the CAA's Accidental Release Program, Section 112(r)(3). According to EPA, there are 14 major areas found in 20 different states where hydrogen sulfide is commonly found in natural gas deposits. As a result of drilling in these areas, "the potential for routine [hydrogen sulfide] emissions is significant." See EPA, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas*, EPA-453/R-93-045, October 1993, at ii, III-35; see also ii, II-5 to II-11.

[21] 42 U.S.C. 7401 *et seq*. For a summary of the CAA and EPA's air and radiation activities and its authorities, see EPA's website at http://www.epa.gov/air/basic.html; and CRS Report RL30853, *Clean Air Act: A Summary of the Act and Its Major Requirements*, by James E. McCarthy.

[22] *Outdoor* is defined as that to which the public has access (see 40 C.F.R. §50.1(e)).

National Ambient Air Quality Standards

Section 109 of the CAA requires EPA to establish National Ambient Air Quality Standards (NAAQS) for air pollutants that may reasonably be anticipated to endanger public health or welfare and whose presence in ambient air results from numerous or diverse sources. Using this authority, EPA has promulgated NAAQS for SO_2, particulate matter ($PM_{2.5}$ and PM_{10}), nitrogen dioxide (NO_2), CO, ozone, and lead. States are required to implement specified air pollution control plans to monitor these pollutants and ensure that the NAAQS are met or "attained." Additional measures are required in areas not meeting the standards, referred to as "nonattainment areas." "Nonattainment" findings for ozone, NO_2, and SO_2 in areas with crude oil and natural gas operations have resulted in states establishing specific pollution control mechanisms that affect the industry.

New Source Performance Standards

Section 111 of the CAA requires EPA to promulgate regulations establishing emission standards that are applicable to new, modified, and reconstructed sources—if such sources cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. A New Source Performance Standard (NSPS) reflects the degree of emission limitation achievable through the application of the "best system of emission reduction," which EPA determines has been adequately demonstrated. EPA has had minimum standards for VOCs and SO_2 at processing facilities in the oil and gas industry for over a decade.[23]

Under the Obama Administration, on August 16, 2012, EPA promulgated new standards for several sources in the "Crude Oil and Natural Gas Production" source category never before regulated at the federal level. The 2012 standards aim to control VOC emissions from new or modified onshore natural gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, and leaking components at onshore natural gas processing plants as well as SO_2 emissions from new or modified onshore natural gas processing plants.[24]

The 2012 standards include, most prominently, a requirement for producers to reduce VOC emissions by 95% from an estimated 11,000 new hydraulically fractured gas wells each year through the use of "reduced emissions completions" (RECs) or "green completions." RECs are defined by EPA as "well completion[s] following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere." The rule also requires certain pneumatics, storage vessels, and compressors to achieve at least a 95% reduction of VOC emissions.

On December 31, 2014, EPA made several amendments to the 2012 standards, including (1) establishing the definition of *flowback period* for the purposes of compliance, (2) making several

[23] In 1979, the EPA published a list of source categories, including "crude oil and natural gas production," for which the EPA would promulgate standards of performance under Section 111(b) of the CAA. EPA, "Priority List and Additions to the List of Categories of Stationary Sources," 44 *Federal Register* 49222, August 21, 1979.

[24] EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012. These standards, in part, revised existing standards promulgated by EPA, including NSPS for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants (40 C.F.R. Part 60, Subpart KKK) and NSPS for SO_2 Emissions for Onshore Natural Gas Processing (40 C.F.R. Part 60, Subpart LLL). The new NSPS are codified as 40 C.F.R. Part 60, Subpart OOOO.

changes to storage vessel provisions, and (3) removing an affirmative defense provision that shielded facility operators from civil penalties for violations resulting from malfunction.[25]

On June 3, 2016, EPA promulgated updates to the 2012 standards "for methane and VOC emissions from new and modified oil and gas production sources, and natural gas processing and transmission sources."[26] The 2016 rule sets first-ever controls for methane emissions and extends controls for VOC emissions beyond the previously existing requirements to include new or modified hydraulically fractured oil wells, pneumatic pumps, compressor stations, and leak detection and repair at well sites, gathering and boosting stations, and processing plants. The final rule also includes the issuance for public comment of an Information Collection Request (ICR) that would require companies to provide extensive information instrumental for developing comprehensive regulations to reduce methane emissions from existing oil and gas sources. In a similar action, EPA finalized Control Techniques Guidelines (CTG) for the oil and natural gas sector, providing recommendations for reducing VOC emissions from existing oil and natural gas industry emission sources in ozone nonattainment areas classified as moderate or higher and in states within the Ozone Transport Region.[27]

In a direct response to the Obama-era standards, and in line with his campaign promises, President Trump signed Executive Order 13783 on March 28, 2017. The order—entitled "Promoting Energy Independence and Economic Growth"—requires agencies to review existing regulations and "appropriately suspend, revise, or rescind those that unduly burden" domestic energy production and use.[28] Section 7 of the executive order specifically directs the EPA Administrator to review several regulations related to U.S. oil and gas development, including the agency's methane standards.

Effective March 2, 2017, EPA withdrew the ICR to assess the need for this information and to reduce the burden to businesses during this assessment.[29] The ICR withdrawal was issued shortly after nine state attorneys general and two governors submitted a letter to EPA asking that the ICR be suspended and withdrawn.[30]

On June 5, 2017, EPA published a rule to delay by 90 days the fugitive emissions, pneumatic pump, and professional engineer certification requirements of the 2016 NSPS while the agency reconsiders these provisions.[31] Under the proposal, "sources will not need to comply with these requirements while the stay is in effect."[32] On July 3, 2017, the U.S. Court of Appeals for the District of Columbia Circuit vacated EPA's administrative 90-day stay, agreeing with arguments

[25] EPA, "Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards," 79 *Federal Register* 79018, December 31, 2014.

[26] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Final Rule," 81 *Federal Register* 35823, June 3, 2016.

[27] EPA, "Release of Final Control Techniques Guidelines for the Oil and Natural Gas Industry," 81 *Federal Register* 74798, October 27, 2016.

[28] Executive Order 13783, "Promoting Energy Independence and Economic Growth," 82 *Federal Register* 16093, March 28, 2017.

[29] EPA, "Notice Regarding Withdrawal of Obligation to Submit Information," 82 *Federal Register* 12817, March 7, 2017.

[30] Letter from Ken Paxton, Attorney General, Texas, to E. Scott Pruitt, Administrator, EPA, March 1, 2017, https://www.epa.gov/sites/production/files/2017-03/documents/letter_from_attorneys_general_and_governors.pdf.

[31] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay," 82 *Federal Register* 25730, June 5, 2017.

[32] Letter from E. Scott Pruitt, Administrator, EPA, to petitioner, April 18, 2017, https://www.epa.gov/sites/production/files/2017-04/documents/oil_and_gas_fugitive_emissions_monitoring_reconsideration_4_18_2017.pdf.

that the agency improperly used its authority under CAA Section 307(d)(7)(B) to pause provisions of the rule.[33] On June 16, 2017, EPA proposed rulemaking for a two-year extension to the stay[34] and issued a notice of data availability related to the agency's proposed stay on November 8, 2017.[35] In the notice, EPA provided additional information on several topics raised by stakeholders and solicited comment on the information presented.

On March 12, 2018, EPA published a final rule to make two "narrow" revisions to the 2016 NSPS. The rule removes the requirement that leaking components be repaired during unplanned or emergency shutdowns and provides separate monitoring requirements for well sites located on the Alaskan North Slope.[36] In addition, EPA published a notice of proposed withdrawal, requesting comment, on the 2016 CTG for the oil and natural gas sector.[37]

On October 15, 2018, EPA proposed a larger set of amendments to the 2016 NSPS.[38] The proposal includes changes to the fugitive emissions, pneumatic pump, and professional engineer certification requirements that were the focus of the earlier rule delay. The proposed changes would decrease the frequency for monitoring fugitive emissions at well sites and compressor stations; decrease the schedule for making repairs; expand the technical infeasibility provision for pneumatic pumps to all well sites; and amend the professional engineer certification requirements to allow for in-house engineers. Upon the proposal's release, the agency stated that it "continues to consider broad policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and natural gas sector," and that "these issues will be addressed in a separate proposal at a later date."[39] The October 2018 proposal has not been finalized.

On September 24, 2019, EPA proposed more substantive amendments to the 2012 and 2016 NSPSs that would remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS for both ozone-forming VOCs and GHGs.[40] The amendments would also rescind the methane requirements in the 2016 NSPS that apply to sources in the production and processing segments of the industry. As an alternative, EPA also proposed to rescind the methane requirements that apply to all sources in the oil and natural gas industry without removing any sources from the current source category. The proposed amendments would remove the agency's obligation to develop emission guidelines to address methane emissions from existing sources under Section 111(d) of the Clean Air Act. The proposal also seeks comment on alternative interpretations of the agency's legal authority to regulate

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[33] *Clean Air Council, et al. v. EPA*, No. 17-1145 (D.C. Cir. July 3, 2017).

[34] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements," 82 *Federal Register* 27645, June 16, 2017.

[35] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements," 82 *Federal Register* 51788, November 8, 2017.

[36] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Amendments: Final Rule," 83 *Federal Register* 52056, October 15, 2018.

[37] EPA, "Notice of Proposed Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry," 83 *Federal Register* 10478, March 12, 2018.

[38] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule," 83 *Federal Register* 10628, March 12, 2018.

[39] EPA, "EPA Proposes Amendments to the 2016 New Source Performance Standards for the Oil and Natural Gas Industry: Fact Sheet," https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/proposed-improvements-2016-new-source.

[40] EPA, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," 84 *Federal Register* 50244, September 24, 2019.

pollutants (specifically methane) under Section 111 of the Clean Air Act.[41] The September 2019 proposal has not been finalized.

National Emission Standards for Hazardous Air Pollutants

Section 112 of the CAA requires EPA to promulgate National Emissions Standards for Hazardous Air Pollutants (NESHAPs). NESHAPs are applicable to both new and existing sources of HAPs, and there are NESHAPs for both "major" sources and "area" sources of HAPs.[42] The aim is to develop technology-based standards that require emission levels met by the best existing facilities (commonly referred to as maximum achievable control technology, or MACT, standards). The pollutants of concern in natural gas systems are, most prominently, the BTEX compounds, carbonyl sulfide, and n-hexane. EPA promulgated NESHAPs for both the "Crude Oil and Natural Gas Production" and the "Natural Gas Transmission and Storage" sectors in 1999. These standards contain provisions for both major sources and area sources of HAPs and include storage vessels with flash emissions[43] (major sources only), equipment leaks (major sources only), and dehydrators (major and area sources).[44]

The air standards promulgated on August 16, 2012, revise the existing NESHAPs to establish MACT standards for "small" dehydrators (which were unregulated under the initial NESHAPs), strengthen the leak detection and repair requirements, and retain the existing NESHAPs for storage vessels.

Air Permits

The CAA Amendments of 1990 added Title V, which requires major sources of air pollution to obtain operating permits, and amended the CAA requirements for Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR) preconstruction permits.[45] EPA has delegated primary responsibility for Title V, PSD, and NSR permitting to state and local authorities. Sources subject to the permit requirements generally include new or modified sources that emit or have the potential to emit 10 tons to 250 tons per year, depending upon the pollutant and the area's attainment status. While natural gas processing facilities typically fall under major source determination, most crude oil and natural gas production activities upstream from the processing plant have not been classified as major sources.[46]

[41] In the 2016 NSPS, EPA took the position that the law did not require that the agency, as a prerequisite to regulating methane as part of the NSPS, first make a separate, pollutant-specific determination that GHG emissions (primarily methane) from the oil and natural gas industry cause or significantly contribute to air pollution that may endanger public health or welfare. The 2019 proposal seeks comment on whether the agency should revise this position.

[42] A major source of HAPs is one with the potential to emit in excess of 10 tons per year (Tpy) of any single HAP or 25 Tpy of two or more HAPs combined. Area sources are those sources that are not "major."

[43] Flash emissions occur when produced liquid (crude oil or condensate) is exposed to temperature increases or pressure decreases during the transfer from the production separators (or similar sources) into atmospheric storage tanks.

[44] See NESHAPs from Oil and Natural Gas Production Facilities (40 C.F.R. Part 63, Subpart HH) and NESHAPs from Natural Gas Transmission and Storage Facilities (40 C.F.R. Part 63, Subpart HHH).

[45] 42 U.S.C. §§7661-7661f. For background, see CRS Report RL33632, *Clean Air Permitting: Implementation and Issues*, by Claudia Copeland.

[46] EPA's guidance for "major source" determinations includes consideration of proximity, ownership, and industrial grouping. For a more detailed discussion on major source determination for facilities in the crude oil and natural gas sector, see the "Major Source Aggregation" section of this report.

On June 3, 2016, EPA promulgated rules to clarify the definitions for "major source" categories in the oil and natural gas sector and the conditions under which certain pieces of equipment can be aggregated.[47]

Greenhouse Gas Reporting

In the FY2008 Consolidated Appropriations Act (H.R. 2764; P.L. 110-161), Congress directed EPA to establish a mandatory GHG reporting program (GHGRP) that applies to emissions that are "above appropriate thresholds in all sectors of the economy." EPA issued the Mandatory Reporting of Greenhouse Gases Rule,[48] which became effective on December 29, 2009. It includes annual reporting requirements for many facilities in the crude oil and natural gas sector.[49] EPA collects these data to inform the agency's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

BLM Waste Prevention Standards

In addition to EPA's CAA authorities, Congress authorized BLM to set standards to conserve federal mineral resources under the Mineral Leasing Act of 1920, as amended (30 U.S.C. §181 *et seq.*). Section 225 of the act requires BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land" and, under Section 187, that leases include "a provision that such rules ... for the prevention of undue waste as may be prescribed by [the] Secretary shall be observed."

Under the Obama Administration, on November 18, 2016, BLM promulgated a "Waste Prevention, Production Subject to Royalties, and Resource Conservation" rule,[50] which targets natural gas emissions as a potential waste of public resources and loss of royalty revenue. BLM's rule requires operators of crude oil and natural gas facilities on federal and Indian lands to take various actions to reduce the waste of gas, establishes clear criteria for when flared gas will qualify as waste and therefore be subject to royalties, and clarifies which on-site uses of gas are exempt from royalties.[51]

The BLM rule was eligible for consideration under the Congressional Review Act at the start of the 115th Congress.[52] On February 3, 2017, the House passed a joint resolution of disapproval (H.J.Res. 36) to repeal it. The Senate rejected the motion to proceed on May 10, 2017.

Under the Trump Administration, BLM announced on June 15, 2017, that it would delay the compliance dates of several requirements of the rule that are slated to take effect in January

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47 EPA, "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector: Final Rule," 81 *Federal Register* 35622, June 3, 2016.

48 EPA, "Mandatory Reporting of Greenhouse Gases," 74 *Federal Register* 56260, October 30, 2009.

49 EPA, "Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems," 75 *Federal Register* 74458, November 30, 2010; see final rule revision to Subpart W—Petroleum and Natural Gas Systems—amending 40 C.F.R. Section 98 (i.e., the regulatory requirements for the program). Several amendments to the reporting methodology have been proposed and promulgated since 2010. See EPA's GHGRP data at https://www.epa.gov/ghgreporting.

50 BLM, "Waste Prevention, Production Subject to Royalties, and Resource Conservation, Final Rule," 81 *Federal Register* 83008, November 18, 2016.

51 For more detail on BLM's rule and a comparison of its requirements to EPA's standards, see CRS Insight IN10645, *EPA's and BLM's Methane Rules*, by Richard K. Lattanzio (available to congressional clients from the author by request).

52 See CRS In Focus IF10023, *The Congressional Review Act (CRA)*, by Maeve P. Carey and Christopher M. Davis.

2018.[53] These include "requirements that operators capture a certain percentage of the gas they produce, measure flared volumes, upgrade or replace pneumatic equipment, capture or combust storage tank vapors, and implement leak detection and repair ... programs." The Postponement Notice invoked Section 705 of the APA and concluded that "justice requires [BLM] to postpone the future compliance dates for [certain] sections of the Rule" in light of "the substantial cost that complying with these requirements poses to operators ... and the uncertain future these requirements face in light of the pending litigation and administrative review of the Rule."

On July 5, 2017, California and New Mexico filed a lawsuit in the U.S. District Court for the Northern District of California challenging the legality of the postponement notice.[54] The two states were joined on July 10, 2017, by more than a dozen environmental and tribal groups.[55] On October 4, 2017, the U.S. District Court for the Northern District of California granted both motions and ruled against BLM's initial postponement.[56]

On December 8, 2017, BLM finalized rulemaking to suspend or delay certain requirements contained in the 2016 final rule until January 17, 2019.[57] The bureau stated that it reviewed the 2016 final rule and determined that the costs the rule is expected to impose would exceed the benefits it is expected to generate. On February 22, 2018, the U.S. District Court for the Northern District of California issued an order enjoining the rule.[58] Thus, the rule, as originally promulgated, remains in effect.

On February 12, 2018, BLM proposed a new rule "to revise the 2016 final rule in a manner that reduces unnecessary compliance burdens, is consistent with the BLM's existing statutory authorities, and reestablishes long-standing requirements that the 2016 final rule replaced."[59] BLM finalized the rule on September 28, 2018.[60] The rule rescinds the novel requirements pertaining to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels, and leak detection and repair (LDAR), returning these requirements to the preexisting royalty provisions promulgated in DOI's 1980 Notice to Lessees, NTL-4A.[61] It revises other provisions related to venting and flaring (by placing volume and/or time limits on royalty-free venting and flaring during production testing, emergencies, and downhole well maintenance and liquids unloading) and adds provisions regarding deference to appropriate state or tribal regulation in

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[53] BLM, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Postponement of Certain Compliance Dates," 82 *Federal Register* 27430, June 15, 2017. For more information, see CRS Legal Sidebar WSLG1806, *UPDATE: BLM Venting and Flaring Rule Survives (For Now)*, by Linda Tsang.

[54] Complaint for Declaratory Relief, California v. BLM, No. 3:17-cv-03804-EDL (N.D. Cal. July 5, 2017).

[55] Complaint for Declaratory and Injunctive Relief, Sierra Club et al., v. BLM, No. 3:17-cv-03885 (N.D. Cal. July 10, 2017).

[56] *State of California, et al., v. BLM; Sierra Club, et al., v. Ryan Zinke,* Nos. 17-cv-03804-EDL, 17-cv-3885-EDL, (N.D. Cal. October 4, 2017).

[57] BLM, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Delay and Suspension of Certain Requirements, Final Rule," 82 *Federal Register* 58050, December 8, 2017.

[58] *State of California, et al., v. BLM; Sierra Club, et al., v. Ryan Zinke,* Nos. 17-cv-07186-WHO, 17-cv-07187-WHO (N.D. Cal. February 22, 2018).

[59] BLM, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, Proposed Rule," 83 *Federal Register* 7924, February 22, 2018.

[60] BLM, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, Final Rule," 83 *Federal Register* 49184, September 28, 2018.

[61] DOI, Geological Survey Conservation Division, "Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases," January 1, 1980.

determining when flaring of associated gas from oil wells will be royalty-free. The final rule was effective on November 27, 2018.

PHMSA Pipeline Safety Standards

The U.S. Department of Transportation (DOT) is given primary authority to regulate the safety of pipelines and underground natural gas storage facilities, including design, construction, operation, maintenance, and leak/spill response planning. These activities can affect air quality issues in the downstream sectors of the natural gas supply chain. The authorities stem from several statutes, including the Natural Gas Pipeline Safety Act of 1968 (P.L. 90-481) and the Hazardous Liquid Pipeline Act of 1979 (P.L. 96-129), among others. The Pipeline and Hazardous Materials Safety Administration (PHMSA), within DOT, administers the federal pipeline safety program by establishing safety standards; conducting programmatic inspections of management systems, procedures, and processes; physically inspecting facilities and construction projects; investigating safety incidents; enforcing federal safety requirements; and maintaining a dialogue with pipeline operators.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (P.L. 112-90). The act contains a broad range of provisions addressing pipeline safety. Among the most significant are provisions to increase the number of federal pipeline safety inspectors, require automatic shutoff valves for transmission pipelines, mandate verification of maximum allowable operating pressure for gas transmission pipelines, and increase civil penalties for pipeline safety violations. Altogether, the act imposed 42 mandates on PHMSA regarding studies, rules, maps, and other elements of the federal pipeline safety program. Further, on June 22, 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (P.L. 114-183). The act reauthorizes provisions for PHMSA operational expenses, user fees for underground natural gas storage facility safety, one-call notification programs, community pipeline safety information grants, and the pipeline integrity program. PHMSA has fulfilled many of the requirements under P.L. 112-90 and P.L. 114-183, and others are near completion.[62]

Issues for Congress

The expansion of both industry production and government regulation of natural gas systems has sparked discussion on a number of outstanding issues. Some of the more significant debates involving air quality concerns are outlined in the following sections.

The Regulatory Role of Federal, State, and Local Governments

Federal regulation of air emissions in the oil and gas industry remains controversial. According to EPA, the 2012 and 2016 federal air standards are designed to provide minimum requirements for emissions of air pollutants from the crude oil and natural gas sector that can both protect human health and the environment and allow for continued growth in production. However, some believe that state and local authorities are better positioned to develop these emission standards. They argue that a distant federal bureaucracy unfamiliar with local conditions is rarely the best entity to ensure that environmental needs are balanced with economic growth and job creation. They claim that states can more readily address the regional and state-specific character of many crude oil

[62] For more information on PHMSA authorities, activities, and status of the agency mandates, see CRS Report R44201, *DOT's Federal Pipeline Safety Program: Background and Key Issues for Congress*, by Paul W. Parfomak.

and natural gas activities, including differences in geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics and the effects these components have on air quality. They argue that federal rules add unnecessary and often repetitive requirements on the industry, which may increase project costs and delays with little added benefit. They point to states such as Colorado and Wyoming—both with more stringent air quality controls on the oil and gas industry than the federal government—as examples of where states have succeeded in crafting regulations to balance continued industry growth and environmental protection.

Others disagree, attesting to the inefficiencies caused by a "patchwork" of state and local requirements. They support the need for the federal government to institute minimum standards for emissions that are consistent and predictable and reach across state lines. They claim that a federal standard could extend regulatory certainties to the industry and avoid a "race to the bottom" among localities competing to attract development. Moreover, they argue that the same federalist system used in virtually all other environmental programs should be applied, whereby the federal government sets a minimum national floor and states are given flexibilities in their approach to implementation. They observe that, in other federal-state collaborative regulatory programs, states have benefitted from sharing "lessons learned" about the availability and cost-effectiveness of chosen technologies and practices.

Measurement of Emissions

The 2012 and 2016 federal air standards are based on EPA's emissions estimates for the crude oil and natural gas sector. While emissions from some activities and equipment may lend themselves to credible estimates, others—specifically fugitive emissions from production activities such as hydraulically fractured well completions, flowback, and produced water ponds—are more difficult to evaluate, have fewer data available, and remain under considerable debate. Currently, the primary source of information on emissions from the sector is a methane study published in 1996 by EPA and the Gas Research Institute.[63] EPA uses this methodology to calculate the industry's GHG emissions and publishes these data annually in the agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

EPA's GHG inventory is a "bottom-up" approach, employing commonly accepted emission factors and activity levels to calculate aggregate estimates for all source categories. While some of this methodology has been representative over the period of 1996 to the present, much of it has been revised and recalculated based on new information received through the inventory preparation process, formal public notice periods, GHGRP data, and academic studies.

Differences in modeling, reported data, analytic assumptions, and levels of uncertainty have resulted in significant fluctuations in methane emissions estimates. (For example, EPA's estimates for natural gas systems have fluctuated between 96.4 million metric tons of carbon dioxide equivalent [$MMTCO_2e$] and 221.2 $MMTCO_2e$ over the past several years due primarily to changes in reporting methodology.)[64] This uncertainty is illustrated in **Figure 1**, which presents

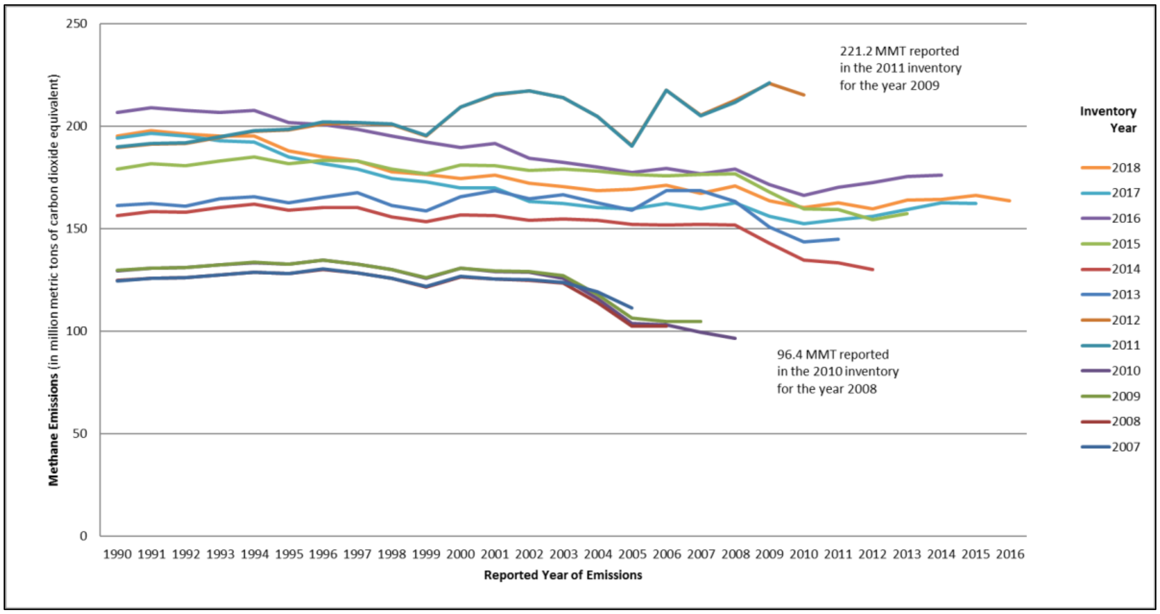
[63] Gas Research Institute and EPA, *Methane Emissions from the Natural Gas Industry, Volumes 1-15,* GRI-94/0257 and EPA 600/R-96-080, June 1996, https://www.epa.gov/sites/production/files/2016-08/documents/1_executiveummary.pdf. The study was an outgrowth of the analysis taken by EPA pursuant to U.S. commitments under the United Nations Framework Convention on Climate Change and the Intergovernmental Panel on Climate Change's "Guidelines for National Greenhouse Gas Inventories."

[64] For more discussion of current emission estimates and historical trends, see CRS In Focus IF10752, *Methane Emissions: A Primer*, by Richard K. Lattanzio.

the historical methane emissions estimates for each GHG inventory from 2007 to 2018 based upon each inventory's methodology.

EPA's GHG inventory has been criticized by industry groups and other sources, many of which have put forth competing—and sometimes conflicting—estimates.[65] Efforts are ongoing at producing a current, comprehensive, and consistent emissions data set for the sector.[66]

Figure 1. EPA's GHG Inventories of Methane Emissions from Natural Gas Systems, 2007-2018



Source: CRS, with data from EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* multiple years.

Notes: EPA updates its modeling assumptions for the sector and recalculates the historical emissions every year for the publication of its inventory. The figure shows estimates for each reported year back to 1990 under the methodologies used for each inventory year from 2007 to 2018 (e.g., the line for "Inventory Year 2018" shows the emissions estimates for the sector for "Reported Years 1990-2016" based upon the modeling assumptions used in 2018).

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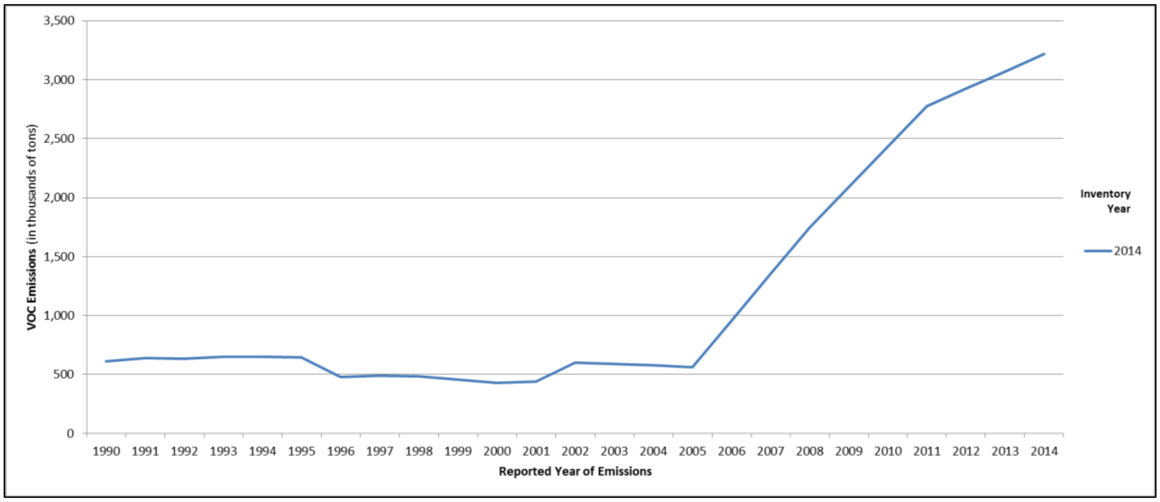
65 See, for example, Scott Miller, "Anthropogenic Emissions of Methane in the United States," *Proceedings of the National Academy of Sciences of the United States of America*, vol. 110, no. 50 (December 10, 2013), http://www.pnas.org/content/110/50/20018.abstract, which provides methane emission estimates for the industry roughly 50% greater than that reported by EPA; and Karin Ritter et al., *Understanding GHG Emissions from Unconventional Natural Gas Production*, 2012, http://www.epa.gov/ttnchie1/conference/ei20/session3/kritter.pdf, which provides methane emission estimates roughly half of that reported by EPA for several source categories.

66 Efforts include (1) EPA's efforts to update its *Inventory*, as outlined in its annual reporting, https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems; (2) the Environmental Defense Fund's *Methane Leakage Study*, http://www.edf.org/methaneleakage; and (3) several data harmonization studies of existing inventories (e.g., U.S. Department of Energy, National Renewable Energy Laboratory, "Life Cycle Assessment Harmonization," https://www.nrel.gov/analysis/life-cycle-assessment.html). Further, on June 21, 2017, EPA's inspector general launched a planned investigation of how the agency estimates methane emissions from the oil and gas sector, as described in OIG's annual plan for FY2017, released December 2016 (see James Hatfield, Director, Air Evaluations, Office of Program Evaluation, letter to Sarah Dunham, Acting Assistant Administrator Office of Air and Radiation, "Project Notification: Evaluation of EPA's Estimation of Methane Emissions from the Oil and Natural Gas Production Sector," June 21, 2017, https://www.epa.gov/office-inspector-general/notification-evaluation-epas-estimation-methane-emissions-oil-and-natural).

Complicating the uncertainty of measuring methane emissions from crude oil and natural gas systems is EPA's additional and unassociated inventory for VOC emissions: EPA's National Emissions Inventory (NEI).[67] The NEI is an estimate of criteria pollutants, criteria precursors, and HAPs from air emissions sources across the United States. It is released every three years and is based primarily upon data provided by state, local, and tribal air agencies for sources in their jurisdictions and supplemented by data developed by EPA. As with the GHG inventory, differences in modeling, reported data, analytic assumptions, and levels of uncertainty have resulted in significant fluctuations in VOC emissions estimates. **Figure 2** presents the 2014 NEI emissions trends estimates for VOCs from the "Petroleum and Related Industries" source sector. While emissions of VOCs from crude oil and natural gas systems are generally analogous with emissions of methane, the NEI presents distinctly different data from the GHG inventory. The disparity may be due to differences in structure, aim, definitions, and methodologies between the two inventories as well as underlying analytic uncertainties.

Figure 2. EPA's Inventory of Volatile Organic Compound Emissions from Petroleum and Related Industries, 2014



Source: CRS, with data from EPA, *2014 National Emissions Inventory,* Average Annual Emissions of Criteria Pollutants, National Tier 1, 1970-2016.

Covered Sources and Pollutants

The 2012 federal air standards focus primarily on the upstream sectors of the oil and gas industry and cover only some of the pollutants and potential sources of emissions. The standards regulate emissions of VOCs from some of the equipment and activities at new or modified onshore natural gas well sites, gathering and boosting stations, and processing plants. Similarly, the standards regulate emissions of SO_2 from new or modified sweetening units at some natural gas processing plants as well as HAPs from some dehydration units and storage facilities in the sector. The scope of the 2012 federal standards is the result of several factors, including (1) statutory limitations placed upon the agency by provisions in the CAA, (2) EPA-conducted cost-benefit and risk analyses, and (3) stakeholder comments provided to the agency during rulemaking.[68]

[67] EPA, 2014 National Emissions Inventory, volume 1, https://www.epa.gov/air-emissions-inventories.

[68] In the CAA, as amended, Congress sets statutory limitations on EPA's authority to regulate emissions from natural gas systems in several instances. These include specific limitations, such as major and area source determinations for

In response to stakeholder comments and legal proceedings, EPA revisited the 2012 NSPS to cover additional sources and pollutants. Most notably, the 2016 NSPS introduces first-ever controls on methane emissions from new or modified equipment and activities in the oil and gas sector, as well as requirements for new or modified hydraulically fractured oil wells, new or modified onshore pneumatic pumps, new or modified onshore transmission and storage sector compressors and pneumatics, and leak detection and repair requirements for sectors beyond the processing plant.

The 2019 NSPS proposal would rescind controls for several of these sources and pollutants, removing all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS for both ozone-forming VOCs and GHGs and removing the methane requirements that apply to sources in the production and processing segments of the industry.

Notwithstanding these requirements, other pollutants from natural gas systems remain unaddressed by any federal law or regulation, and critics point specifically to H_2S as the most significant omission.[69] Further, federal standards do not cover emissions from offshore sources, coalbed methane production facilities, field engines, drilling rig engines, turbines, well-head compressors, well-head activities such as liquids unloading, heater-treaters, storage cellars, sumps, and produced water ponds. Also, due to statutory limitations in the CAA, federal emission standards do not cover VOC or SO_2 emissions from existing sources unless the emissions are classified as HAPs. Finally, EPA's standards do not cover methane emissions from existing sources.[70]

Major Source Aggregation

Determinations for which activities and pieces of equipment are considered "major sources" of pollution with respect to CAA Title V operating permits and Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR) preconstruction permits have been controversial.[71] The 2012 federal air standards exempt well completions, pneumatic controllers, compressors, and storage vessels from the classification of "major source" (i.e., one that emits typically 10 tons to 250 tons per year, depending upon the pollutant and the area's attainment status).

Viewed at the component level, discrete "emissions units" at natural gas facilities may not generate enough pollution individually to be classified as "major sources." However, it may be possible that a combination of discrete "emissions units" at a natural gas operation (e.g., a well site, field, or station) could be grouped together, or "aggregated," as a "major source." For example, under the PSD permitting program, to determine whether emitting facilities should be aggregated for permitting purposes, EPA has defined *major stationary source* to include "any

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HAPs in Section 112(n), as well as more general limitations, such as the classification of some pollutants prevalent in the industry (e.g., hydrogen sulfide).

[69] H_2S is covered under the Accidental Release Program, Section 112(r)(3) of the CAA; however, it is not listed as a HAP under Section 112(b)(1). H_2S emissions are typically addressed by state and local requirements (e.g., permits and nuisance abatement authorities).

[70] The possibility remains open for EPA to propose performance standards on methane emissions for existing sources in the future. That is, for certain pollutants, promulgation of NSPS under Section 111(b) triggers a mandatory EPA duty under CAA Section 111(d) to address existing sources in the same source category. At present, however, there is a looming legal question as to precisely what those "certain pollutants" are. This question is likely to be debated in the litigation over EPA's Clean Power Plan.

[71] See, for example, *Summit Petroleum Corp. v. EPA*, 6th Cir., Nos. 09-4348, 10-4572, 8/7/12.

[emitting] building, structure, facility, or installation" that is (1) in the same industrial grouping per Standard Industrial Classification ("SIC") codes; (2) located on "contiguous or adjacent" properties; and (3) under common control of the same person or persons.[72] The Title V major source definition is consistent with the language and application of the PSD major source definition.[73] These factors are determined on a case-by-case basis for each permitting decision.

Defining what emitting facilities are "contiguous or adjacent" for purposes of major source determinations has been interpreted differently by the states, EPA, the courts, and regulated entities. Most recently, EPA finalized rules to clarify the meaning of the term *adjacent* that is used to determine the scope of a "stationary source" in the oil and natural gas sector (published on June 3, 2016, in conjunction with the 2016 NSPS).[74] The effectiveness of these new guidelines has yet to be determined.

In contrast to the permitting requirements for PSD, NSR, and Title V pollutants (e.g., VOCs and SO_2 for the oil and gas sector), "major" and "area" source determinations for NESHAPs in the sector are clearly outlined in the CAA. In Section 112(n)(4), Congress specifically exempts upstream crude oil and natural gas operations from aggregation to determine both major and area source categories for HAPs, excepting some activities near metropolitan areas with populations in excess of 1 million.

Impacts of Emissions

The 2012 and 2016 federal air standards are based on EPA's expectations that the avoided emissions under the rules would result in improvements in air quality and reductions in health effects associated with exposure to HAPs, ozone, and methane. However, the relationship between air pollution from natural gas systems and its impacts on human health and the environment has yet to be fully quantified and assessed. EPA acknowledges this shortcoming in the 2012 rule's proposal, stating that a full quantification of health benefits for the standards could not be accomplished due to the "unavailability of data and the lack of published epidemiological studies correlating crude oil and natural gas production to respective health outcomes."[75] Nevertheless, it should be noted that comprehensive epidemiological studies are generally difficult, rare, and expensive to conduct, requiring data that are typically absent or inadequate for assessment (e.g., precise and accurate estimates of emissions, fate and transport, and exposure levels as well as impact data on relatively large populations of exposed individuals over extended durations of time).

Various stakeholders assert that the lack of published and peer-reviewed literature makes it challenging to scientifically assess the impacts of natural gas operations. Some contend that this uncertainty argues against additional pollution controls at this time. Others maintain that the relevant question for determining whether pollution controls are necessary is whether natural gas systems impact an area's ability to attain air quality standards (NAAQS) or the country's ability to achieve its GHG reduction targets.

[72] 40 C.F.R. 52.21(b)(5)-(6); 40 C.F.R. 51.165(a)(1)(i)-(ii); 40 C.F.R. 51.166(b)(5)-(6).

[73] 61 *Federal Register* 34202, 34210, July 21, 1996.

[74] EPA, "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector: Final Rule," 81 *Federal Register* 35622, June 3, 2016. The rule defines *adjacency* to mean equipment and activities in the oil and gas sector that are under common control and are located near each other—specifically, on the same site or on sites that share equipment and are within one-quarter of a mile of each other.

[75] EPA, *Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry*, July 2011, p. 4-1.

From a selection of recent studies, some of the impacts of emissions from natural gas systems have been reported as follows:

- Some reports have shown significant increases in VOC and/or ozone levels in several areas of the country with heavy concentrations of drilling, including the Marcellus Basin in Pennsylvania and West Virginia,[76] the Piceance and Denver-Julesburg Basins in Colorado,[77] the Green River Basin in Wyoming,[78] and the Uinta Basin in Utah.[79] Research (from academia and state-level environmental agencies) attributes the rise in industry-related VOC emissions primarily to increased traffic, combustion exhaust, and local emissions from oil and gas development activities. However, others note that the presence of VOCs in the atmosphere is only one of the many factors that contribute to ground-level ozone formation. Several other surveys of air quality in these regions have shown increases in ozone values due to effects such as stratospheric ozone intrusions[80] as well as drops in ozone values due to mitigating circumstances such as reductions in NO_x concentrations and changes in weather patterns (e.g., the Fort Worth[81] and Uinta[82] Basins).
- Several local, state, and national health agencies have expressed concerns about the health impacts of HAPs and other emissions from natural gas facilities, including the National Institute of Environmental Health Sciences,[83] the Agency for Toxic Substances and Disease Registry (ATSDR),[84] the New York State Department of Health,[85] and the Colorado School of Public Health,[86] among

[76] Timothy Vinciguerra et al., "Regional Air Quality Impacts of Hydraulic Fracturing and Shale Natural Gas Activity: Evidence from Ambient VOC Observations," *Atmospheric Environment*, vol. 110 (June 2015), pp. 144-150.

[77] Colorado Department of Public Health and Environment, Air Pollution Control Division, *Oil and Gas Emission Sources Presentation for the Air Quality Control Commission Retreat*, May 15, 2008, pp. 3-4.

[78] Wyoming Department of Environmental Quality, *Technical Support Document I for Recommended 8-Hour Ozone Designation of the Upper Green River Basin*, March 26, 2009.

[79] Randal Martin et al., *Final Report: Uinta Basin Winter Ozone and Air Quality Study, December 2010-March 2011*, Energy Dynamics Laboratory, Utah State University, for Uintah Impact Mitigation Special Service District, June 14, 2011, https://binghamresearch.usu.edu/files/edl_2010-11_report_ozone_final.pdf.

[80] Technical Services Program, Air Pollution Control Division, Colorado Department of Public Health and Environment, "Technical Support Document for the May 24, 2010, Stratospheric Ozone Intrusion Exceptional Event," October 7, 2011, https://www.colorado.gov/airquality/tech_doc_repository.aspx?action=open&file=TSD_O3_Intrusion_Event_052410.pdf.

[81] Texas Commission on Environmental Quality, "A Commitment to Air Quality in the Barnett Shale," *Natural Outlook Newsletter*, Fall 2010, https://www.tceq.texas.gov/assets/public/comm_exec/pubs/pd/020/10-04/Outlook-Fall-2010.pdf.

[82] Utah Department of Environmental Quality, *Ozone in the Uintah Basin*.

[83] National Institute of Environmental Health Sciences, "Hydraulic Fracturing and Health," https://www.niehs.nih.gov/health/topics/agents/fracking/index.cfm.

[84] ATSDR, Health Consultation: Public Health Implications of Ambient Air Exposure to Volatile Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas Garfield County, Colorado, March 13, 2008, https://www.atsdr.cdc.gov/hac/pha/Garfield_County_HC_3-13-08/Garfield_County_HC_3-13-08.pdf.

[85] New York State Department of Health, "A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development," December 2014, https://www.health.ny.gov/press/reports/docs/high_volume_hydraulic_fracturing.pdf.

[86] Roxana Witter et al., *Health Impact Assessment for Battlement Mesa, Garfield County, Colorado*, Colorado School of Public Health, 2010, https://www.garfield-county.com/public-health/documents/1%20%20%20Complete%20HIA%20without%20Appendix%20D.pdf; Lisa McKenzie et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Sci Total Environ.*, May

others. These investigations were spurred by community health complaints in regard to natural gas operations such as strong odors, dizziness, nausea, respiratory problems, and eye and skin irritation, and more severe concerns including cancer. Some of the reports identified, on average, slightly elevated cancer risks at some sites. Most recommended further investigation into HAP emissions and risks at all sites.

- Finally, a variety of studies have examined the impacts—both positive and negative—of GHG emissions from natural gas systems. Many observe that the combustion of natural gas is less carbon-intensive than other fossil fuels (i.e., on a per-unit-of-energy basis) and claim that fuel switches to natural gas would benefit the climate by reducing overall CO_2 emissions. Other studies, however, focus on the potential impacts of fugitive methane releases. They argue that fugitive methane may contribute significantly to GHG emissions from the sector and may counteract some of the environmental benefits that the U.S. economy has to gain by switching from coal or oil to natural gas.[87]

Cost-Benefit Analysis of Federal Standards

Natural gas is a product of—and thus a source of revenue for—the oil and gas industry. It is also a source of pollution from the industry when it is emitted into the atmosphere. Due to this unique linkage, pollution abatement has the potential to translate into economic benefits for the industry, as producers may be able to offset some compliance costs with the value of natural gas products recovered and sold. To capitalize on these incentives, many recovery technologies have been incorporated into industry practices.[88] Whether product recovery is profitable for producers may depend upon a number of factors, including the nature and extent of the release, the technology available for capture, and the market price for the recovered products. Because these factors vary significantly over time and place, incentives to control for emissions based solely on market forces have been inconsistent.

Both EPA and BLM considered the costs and the benefits of their respective rulemakings on the crude oil and natural gas sector. These considerations were conducted as required by statute (e.g., CAA,[89] MLA)[90] and by executive orders and guidance (e.g., Executive Order 12866, "Regulatory

1, 2012, 424:79-87, http://www.sciencedirect.com/science/article/pii/S0048969712001933.

[87] For more discussion of methane's GHG emissions impacts in the power sector, see CRS Report R44090, *Life-Cycle Greenhouse Gas Assessment of Coal and Natural Gas in the Power Sector*, by Richard K. Lattanzio.

[88] For examples of available technologies and operating practices and the marginal costs associated with their employment, see, for example, ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," prepared for the Environmental Defense Fund, March 2014, http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

[89] The CAA defines *standard of performance* as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated" (42 U.S.C. 7411(a)(1)). The CAA does not provide specific direction regarding what metric or metrics to use in considering costs for a standard of performance, affording EPA considerable discretion in choosing a means of cost consideration.

[90] The MLA requires BLM to set royalty rates and determine the quantity of produced oil and gas that is subject to royalties under the terms and conditions of a federal lease. The MLA also requires BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land" (30 U.S.C. 225). BLM has long read the MLA to exempt from royalty payments production that is "unavoidably lost" in the course of production. (See 44 *Federal Register* 76600.) In determining when production is unavoidably versus avoidably lost, BLM has generally considered the technical and economic feasibility of preventing the loss of gas. (See BLM, "Notice to Lessees and

Planning and Review"; Executive Order 13563, "Improving Regulation and Regulatory Review"; and Circular A-4 from the Office of Management and Budget [OMB]).[91] Neither the CAA nor the MLA requires that the regulatory agency set the level of control based on a cost-benefit analysis (CBA). However, executive orders require developing and considering CBA, as well as producing a RIA and other administrative addenda.[92] Specifically, the executive orders encourage agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." As such, to the extent allowed by law,[93] the agencies have generally sought options that yield only net benefits (i.e., that are worth more to society than they cost).

In their respective analyses, the agencies calculated regulatory compliance costs for the affected industry to include initial capital costs and annualized engineering costs. These calculations incorporated estimates for new technology investment, increased monitoring and reporting requirements, and the adoption of additional management or workplace practices. Costs were then adjusted for the estimated revenues generated from the recovered natural gas and other products that would otherwise have been vented or flared.

The agencies calculated regulatory benefits in both monetized and nonmonetized terms. Monetized benefits included those from reductions in methane emissions, which were valued using the social cost of methane ($SC\text{-}CH_4$).[94] Nonmonetized benefits included estimates for improvements in ambient air quality and reductions in negative health effects associated with exposure to hazardous air pollutants, ozone, and particulate matter, which the agencies determined could not be adequately monetized with the data currently available. In addition to

Operators of Onshore Federal and Indian Oil and Gas Leases (NTL-4A): Royalty or Compensation for Oil and Gas Loss," January 1, 1980, https://www.ntc.blm.gov/krc/uploads/172/NTL-4A%20Royalty%20or%20Compensation%20for%20Oil%20and%20Gas%20Lost.pdf.)

[91] Under Executive Orders 12866 and 13563, each economically significant regulatory action taken by covered agencies (under any statutory authority) must include estimates of the cost and benefits of the action in Regulatory Impact Analyses (RIAs) before it is proposed and again before it is promulgated. These RIAs can play a major role in the interagency review process overseen by the OMB, which precedes the publication of most agencies' significant proposed and final rules in the *Federal Register*. See Executive Order 12866, "Regulatory Planning and Review," 58 *Federal Register* 51735, October 4, 1993; and Executive Order 13563, "Improving Regulations and Regulatory Review," 76 *Federal Register* 3821, January 21, 2011. For more on this OMB review process, see CRS Report RL32397, *Federal Rulemaking: The Role of the Office of Information and Regulatory Affairs*, coordinated by Maeve P. Carey.

[92] See CRS Report R41974, *Cost-Benefit and Other Analysis Requirements in the Rulemaking Process*, coordinated by Maeve P. Carey.

[93] Some statutory provisions require other criteria for setting the stringency of a regulation, for example, to protect the most vulnerable populations.

[94] EPA and other federal agencies have used metrics recommended by an interagency working group and publicly peer reviewed for the social cost of carbon ($SC\text{-}CO_2$) to estimate the climate benefits of rulemakings. EPA and BLM have used, in a few cases, the $SC\text{-}CH_4$, which employs similar methods but for methane (published citation below). The $SC\text{-}CO_2$ and $SC\text{-}CH_4$ are estimates of the economic damages associated with a small increase in CO_2 and methane emissions, conventionally analyzed as one metric ton, in a given year. The stream of projected future avoided damages due to those emissions, translated into monetary values, are discounted back to a single "net present value" for the year of emissions. The avoided damages noted, in their analytical documentation, are not comprehensive of all likely climate change damages, though they include changes in net agricultural and forest productivity, human health, protection against sea level rise, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. They also include damages outside of the United States, a major point of contention raised by critics. See CRS In Focus IF10625, *Social Costs of Carbon/Greenhouse Gases: Issues for Congress*, by Jane A. Leggett.

these health improvements, nonmonetized benefits included improvements in visibility, ecosystem effects, and additional natural gas recovery.

The 2012 NSPS require natural gas producers to use recovery technologies to capture approximately 95% of the methane and VOCs that escape into the air as a result of hydraulic fracturing operations. At the time, EPA reported the potential environmental benefits of the 2012 standards as follows: VOC reductions of 190,000 tons annually, air toxics reductions of 12,000 tons annually, and methane reductions of 1.0 million tons annually. The agency estimated that the equipment and the activities required to comply with the 2012 standards would cost producers about $170 million per year but that incorporating the sale of recovered products into the cost would result in an estimated net gain of about $11 million to $19 million per year. The industry disagreed with these estimates and countered with compliance costs at more than $2.5 billion annually.[95] Third parties, such as Bloomberg Government, projected a net cost between $316 million and $511 million.[96]

For the 2016 NSPS, EPA reported the potential environmental benefits by 2025 as follows: VOC reductions of 210,000 tons, air toxics reductions of 3,900 tons, and methane reductions of 510,000 tons.[97] The agency estimated that the total annualized engineering costs of the 2016 NSPS would be $530 million in 2025 (2012 dollars), but it calculated that incorporating the sale of recovered products into the cost would recover approximately $30 million of this total. Using SC-CH_4 metrics, the rule was estimated to yield climate benefits of $690 million in 2025. Industry sources contend that EPA exaggerated the benefits of the 2016 rule, stating that rather than net benefits of more than $100 million, net costs could be $150 million in 2020 and $290 million to $400 million in 2025.[98] Third parties, such as researchers at Stanford University, estimated that the 2016 standards would cost about a third less than what the agency reports but may not lead to the expected emissions reductions.[99]

BLM estimated that the 2016 waste prevention rule would avoid 175,000-180,000 tons of methane emissions per year and yield total benefits from $209 million to $403 million per year, outweighing the costs of $110 million to $275 million per year. BLM estimated annual royalties to the federal government, tribal governments, states, and private landowners to increase by $3 million to $10 million per year. Industry countered with a net benefit assessment of -$143 million to -$278 million for the proposed rule, arguing against the agency's use of the SC-CH_4 metric and other assumptions.[100]

[95] See, for example, Advanced Resources International, *Estimate of Impacts of EPA Proposals to Reduce Air Emissions from Hydraulic Fracturing Operations*, prepared for the American Petroleum Institute, February 2012.

[96] Rich Heidorn Jr., *Fracking Emission Rules: EPA, Industry Miss Mark on Costs, Consequences*, Bloomberg Government, 2012.

[97] EPA, "Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," EPA-452/R-16-002, May 2016.

[98] NERA Economic Consulting, "Technical Comments on the Social Cost of Methane as Used in the Regulatory Impact Analysis for the Proposed Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector," prepared for American Council for Capital Formation, December 3, 2015, http://www.nera.com/publications/archive/2015/technical-comments-on-the-social-cost-of-methane-as-used-in-the-.html.

[99] Arvind Ravikumar and Adam Brandt, "Designing Better Methane Mitigation Policies: The Challenge of Distributed Small Sources in the Natural Gas Sector," *Environmental Research Letters*, vol. 12, no. 4 (April 19, 2017), http://iopscience.iop.org/article/10.1088/1748-9326/aa6791.

[100] American Petroleum Institute, "Comments on BLM's Proposed Waste Prevention and Resource Conservation Rule: Attachment A," April 22, 2016, https://www.regulations.gov/document?D=BLM-2016-0001-9073.

All cost estimates are based on assumptions regarding the quantity of captured emissions, the cost and availability of capital equipment, and the market price for natural gas.[101]

Under the Trump Administration, analysis of the costs and benefits of environmental regulations—specifically estimates regarding the social cost of carbon and methane—are under reconsideration.[102] These reconsiderations affect the cost-benefit analysis of the Obama-era methane standards in significant ways.[103] For the 2019 proposed NSPS, the agency estimated that the oil and natural gas industry would save a total of $97 million to $123 million from 2019 through 2025, or $17 million to $19 million a year. The total cost savings reflected both the cost savings associated with proposed changes to requirements in the rule and the forgone value of natural gas that would not be recovered as a result of those changes. Further, EPA's analysis estimated that certain emissions reductions would not occur from 2019 through 2025 as a result of the proposed amendments, including 370,000 short tons of methane (8.4 $MMTCO_2e$), 10,000 short tons of VOCs, and 300 short tons of HAPs. The analysis reported the total present value of climate benefits within the United States that would not occur at $13 million (under a 7% discount rate) or $52 million (under a 3% discount rate), which translated to $2.3 or $8.1 million per year, respectively.[104]

Conclusion

U.S. natural gas production has grown markedly in recent years. This growth is due in large part to increased activities in unconventional resources brought on by technological advance. Many have advocated for the increased production and use of natural gas in the United States for economic, national security, and environmental reasons. They argue that natural gas is the cleanest-burning fossil fuel, with fewer emissions of CO_2, NO_x, SO_2, PM, and mercury than other fossil fuels (e.g., coal and oil) on a per-unit-of-energy basis. For these reasons, many have looked to natural gas as a "bridge" fuel to a less polluting and lower GHG-intensive economy. However, the recent expansion in natural gas production in the United States has given rise to a new set of concerns regarding human health and environmental impacts, including impacts on air quality.

To address air quality and other environmental issues, the oil and gas industry in the United States has been regulated under a complex set of local, state, and federal laws. Currently, state and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems, and many states have passed laws and/or promulgated rules to address air quality issues based on local needs. Further to this, organizations such as the State Review of Oil and Natural Gas Environment Regulations (STRONGER) are available to help states assess the overall framework of environmental regulations supporting oil and gas operations in their regions.[105]

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[101] For more on the cost-benefit analysis of air quality standards and its use during federal agency rulemaking, see CRS Report R44840, *Cost and Benefit Considerations in Clean Air Act Regulations*, by James E. McCarthy and Richard K. Lattanzio.

[102] EPA, "Increasing Consistency and Transparency in Considering Costs and Benefits in the Rulemaking Process: Advance Notice of Proposed Rulemaking," 83 *Federal Register* 27524, June 13, 2018.

[103] For more discussion on this issue, see CRS In Focus IF10625, *Social Costs of Carbon/Greenhouse Gases: Issues for Congress*, by Jane A. Leggett.

[104] EPA, "Regulatory Impact Analysis for the Proposed Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," August 2019.

[105] STRONGER is a nonprofit, multi-stakeholder organization that specializes in assessing the overall framework of environmental regulations supporting oil and gas operations. Its collaborative review teams encompass industry, regulators, and environmental/public interest stakeholders. For more information, see http://www.strongerinc.org/.

At the federal level, EPA has promulgated minimum national standards for emissions of methane, VOCs, SO_2, and HAPs for some source categories in the crude oil and natural gas sector. Additionally, BLM has promulgated rules to reduce potential waste of public resources and loss of royalty revenue. The federal standards focus primarily on the production and processing sectors of the industry and were drawn, in part, from existing requirements found in the codes of states such as Colorado and Wyoming. These federal standards are currently under reconsideration by the Trump Administration. BLM rescinded many of the novel requirements of its rule on September 28, 2018. EPA proposed to eliminate the novel requirements for methane on September 24, 2019.

Further, many producers in the crude oil and natural gas sector have set forth a series of recommended practices. These practices are sustained by the economic incentives provided by capturing the fugitive releases of natural gas and its byproducts to be sold at market. Several voluntary partnerships sponsored by various federal and international agencies also serve to facilitate recommended practices for emissions reductions in the oil and gas industry. EPA's Natural Gas STAR Program, the Global Methane Initiative (formerly the Methane to Markets Partnership), and the World Bank Global Gas Flaring Reduction Partnership are three such programs.[106]

Debate continues over the regulation of methane, VOC, SO_2, and HAP emissions from the crude oil and natural gas sector. Information and technology are rapidly evolving. Conflicts between federal and state governments remain, and the argument that environmental regulations hinder economic growth continues to be made. Complicating this debate is the fact that a comprehensive national inventory of fugitive emissions from natural gas systems does not exist due to many factors, including costs and technical uncertainties. For these reasons, the choice of policy that returns the most efficient, flexible, cost-effective, and environmentally sound emissions controls on the sector has remained an open question.

Author Contact Information

Richard K. Lattanzio
Specialist in Environmental Policy
[redacted]@crs.loc.gov , 7-....

[106] For more information about EPA's Natural Gas STAR Program, see http://www.epa.gov/gasstar/. For the Global Methane Initiative, see EPA's website, https://www.epa.gov/gmi. For the Global Gas Flaring Reduction Partnership, see the World Bank's website, http://go.worldbank.org/KCXIVXS550.