Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 EXECUTIVE SUMMARY

1.1 Background

The action analyzed in this regulatory impact analysis (RIA) amends the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this rule because methane is a greenhouse gas (GHG), and the oil and natural gas category is the country's largest emitter of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

The EPA is amending the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are establishing both methane and VOC standards for several emission sources not covered by the 2012 NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites, compressor stations, pneumatic pumps). In addition, we are establishing methane standards for certain emission sources that are regulated for VOC under the 2012 NSPS (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). However, we do not expect any incremental benefits or costs as a result from regulating methane for VOC sources regulated under the 2012 NSPS.

With respect to certain equipment that are used across the source category, the 2012 NSPS regulates only a subset of this equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The new amendents establish methane standards for these equipment across the source category and extend the VOC standards from the 2012 NSPS to the remaining unregulated equipment. Lastly, amendments to the 2012 NSPS are established that improve several aspects of the 2012 standards related to implementation. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the 2012 NSPS for the oil and natural gas sector and related amendments. Except for these implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the 2012 standards.

As part of the regulatory process, the EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million annually. The EPA estimates the final NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. This RIA includes an economic impact analysis and an analysis of the climate, health, and welfare impacts anticipated from the final NSPS.[1] We also estimate potential impacts of the rule on national energy markets using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using 3 and 7 percent discount rates.

This analysis estimates regulatory impacts for the analysis years of 2020 to represent the near-term impacts of the rule, and 2025 to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 through 2024 that are assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically-fractured oil wells, capture methane and VOC emissions that otherwise would be vented to the atmosphere. The averted methane emissions can be directed into natural gas production streams and sold. The revenues derived from natural gas recovery are expected to offset a portion of the engineering costs of implementing the NSPS. In this RIA, we present

[1] The analysis in this RIA and the RIA that accompanied the proposal together constitute the economic assessment required by CAA section 317. In the EPA's judgment, the assessment is as extensive as practicable taking into account the EPA's time, resources, and other duties and authorities.

results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The baseline used for the impacts analysis of our NSPS takes into account emissions reductions conducted pursuant to state regulations covering the relevant operations. A detailed discussion on the derivation of the baseline is presented in Section 3 of this RIA.

1.2 Market Failure

Many regulations are promulgated to correct market failures, which lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address “negative externalities” whereby the market does not internalize the full cost of production that is borne by society, as public goods such as air quality are unpriced.

Greenhouse Gas (GHG) and VOC emissions impose costs on society, such as negative climate, health, and welfare impacts. These impacts are not reflected in the market price of the goods produced through the polluting process and are referred to as negative externalities. For this regulatory action, the goods produced, processed, transported, or stored are crude oil, natural gas, and other hydrocarbon products. If an oil and natural gas firm pollutes the atmosphere while extracting, processing, transporting, or storing goods, this cost will not be borne by the polluting firm but by society as a whole. The market price of the products will fail to incorporate the full cost to society of the pollution related to production. All else held equal, the quantity of oil and natural gas produced in a competitive market will not be at the socially optimal level. More oil and natural gas will be produced than would occur if the oil and natural gas producers had to account for the full cost of production, including the negative externality. Consequently, absent a regulation on emissions, the marginal social cost of the last units of oil and natural gas produced will exceed its marginal social benefit.

1.3 Regulatory Options Analyzed in this RIA

In this RIA, we examine three broad regulatory options. Table 1-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for promulgation.

Table 1-1 Emissions Sources and Controls Evaluated for the NSPS

Emissions Point	Emissions Control	Option 1	Option 2 (final)	Option 3
Well Completions and Recompletions				
Hydraulically Fractured Development Oil Wells	REC / Combustion	**X**	**X**	**X**
Hydraulically Fractured Wildcat and Delineation Oil Wells	Combustion	**X**	**X**	**X**
Fugitive Emissions				
Well Sites	Planning, Monitoring and Maintenance	**Annual**	**Semiannual**	**Quarterly**
Gathering and Boosting Stations	Planning, Monitoring and Maintenance	**Semiannual**	**Quarterly**	**Quarterly**
Transmission Compressor Stations	Planning, Monitoring and Maintenance	**Semiannual**	**Quarterly**	**Quarterly**
Pneumatic Pumps				
Well Sites	Route to control	**X**	**X**	**X**
Pneumatic Controllers				
Natural Gas Transmission and Storage	Emissions limit	**X**	**X**	**X**
Reciprocating Compressors				
Natural Gas Transmission and Storage	Maintenance	**X**	**X**	**X**
Centrifugal Compressors				
Natural Gas Transmission and Storage	Route to control	**X**	**X**	**X**

Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers and pumps.

Options 1 and 3 differ from the finalized Option 2 with respect to the requirements for fugitive emissions. Well site fugitive requirements under Option 1 are annual, while new or modified gathering and boosting station and new or modified transmission and storage compressor stations require a semiannual fugitive emission survey and repair program. Less frequent survey requirements lead to lower costs as well as lower emissions reduction compared to the selected Option 2. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in greater emission reductions, however there are also increased costs, resulting in a net effect of lower net benefits compared to the finalized Option 2.

1.4 Summary of Results

For the final NSPS, a summary of the key results of the RIA for the final standards (Option 2) follow. Key results for Options 1 through 3 are summarized in Table 1-2 through Table 1-4, respectively. Note all dollar estimates are in 2012 dollars:

- **Emissions Analysis:** The final NSPS is anticipated to prevent significant new emissions, including 300,000 short tons of methane, 150,000 tons of VOCs and 1,900 tons of hazardous air pollutants (HAP) in 2020, increasing to 510,000 short tons of methane, 210,000 tons of VOCs, and 3,900 tons of HAP prevented in 2025.[2] The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025.
- **Benefits Analysis:** The monetized benefits in this RIA include those from reducing methane emissions, which are valued using the social cost of methane (SC-CH_4).[3] The EPA estimates that, in 2020, the rule will yield monetized climate benefits of $160 million to approximately $950 million; the mean SC-CH_4 at the 3% discount rate results in an estimate of about $360 million in 2020. In 2025, the EPA estimates monetized climate benefits of $320 million to approximately $1.8 billion; the mean SC-CH_4 at the 3% discount rate results in an estimate of about $690 million in 2025.[4] While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in negative health effects associated with exposure to HAP, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule.[5] This is not to imply that there are no health benefits

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[2] Estimates are presented in short tons.

[3] The social cost of methane (SC-CH_4) is the monetary value of impacts associated with a marginal change in methane emissions in a given year.

[4] The range of estimates reflects four SC-CH_4 estimates and are associated with different discount rates (model average at 2.5, 3 and 5 percent; 95th percentile at 3 percent). See Section 4.3 for a complete discussion.

[5] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in

anticipated from the final NSPS; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits.

- **Engineering Cost Analysis:** The EPA estimates the total capital cost of the final NSPS to be \$250 million for affected sources in 2020 and \$360 million for affected sources in 2025. The estimate of total annualized engineering costs of the final NSPS is \$390 million in 2020 and \$640 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the NSPS are estimated to be \$320 million in 2020 and \$530 million in 2025, assuming a wellhead natural gas price of \$4/thousand cubic feet (Mcf). The estimated engineering compliance costs that include product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can influence estimated engineering costs. For example, \$1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about \$16 million in 2020 and \$27 million in 2025, given the EPA estimates that about 16 million Mcf in 2020 and 27 million Mcf of natural gas will be recovered by implementing the NSPS. When using a 3 percent discount rate, the estimate of total annualized engineering costs of the final NSPS is \$380 million in 2020 and \$630 million in 2025, or \$320 million in 2020 and \$520 million in 2025, when estimated revenues from additional natural gas are included.
- **Energy Markets Impacts Analysis:** The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy markets. We estimate that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period relative to the baseline (by about 0.17 percent for natural gas wells and about 0.02 percent for crude oil wells). Natural gas production decreases slightly over the 2020 to 2025 period under the rule relative to the baseline (by about 0.03 percent), while crude oil production does not vary appreciably. Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (about 0.20 percent). Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period (by about 0.11 percent) relative to the baseline. Crude oil net imports are not estimated to to change appreciably over the 2020 to 2025 period relative to the baseline.
- **Small Entity Analyses:** To understand the potential impact of the rule on small entities, the EPA conducted a screening analysis of the potential impacts by estimating the ratio of potential compliance costs to firm sales (i.e. a cost-to-sales test). Based on the results of this screening analysis, the EPA concluded that it is unable to certify that the final rule

that study are derived from total VOC emissions across all sectors. Larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ coupled with the highly localized nature of air quality responses associated with VOC reductions, lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). The EPA convened a Small Business Advisory Review panel and completed an Inititial Regulatory Flexibility Analysis before proposing the rule. The EPA also completed a Final Regulatory Flexibility Analysis for the final rule.

- **Employment Impacts Analysis:** The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment and control activities, as well as the labor associated with new reporting and recordkeeping requirements. The EPA estimated one-time and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The one-time labor requirement to comply with the final NSPS is estimated at about 270 FTEs in 2020 and in 2025. The annual labor requirement to comply with the NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. The EPA notes that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 1-2 presents the summary results for Option 1, Table 1-3 presents summary results for Option 2, and Table 1-4 presents summary results for Option 3.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$290 million	$540 million
Total Costs[2]	$240 million	$360 million
Net Benefits[3]	$54 million	$180 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM2.5 and ozone exposure from 130,000 tons of VOC reduced	Health effects of PM2.5 and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 1,300 tons of HAP reduced	Health effects of HAP exposure from 2,700 tons of HAP reduced
	Health effects of ozone exposure from 250,000 tons of methane	Health effects of ozone exposure from 390,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the additional benefit estimates range from $130 million to $780 million in 2020 and $250 million to $1.4 billion in 2025 for Option 1, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 5.6 million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

Table 1-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Finalized Option) in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$360 million	$690 million
Total Costs[2]	$320 million	$530 million
Net Benefits[3]	$35 million	$170 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM2.5 and ozone exposure from 150,000 tons of VOC reduced	Health effects of PM2.5 and ozone exposure from 210,000 tons of VOC reduced
	Health effects of HAP exposure from 1,900 tons of HAP reduced	Health effects of HAP exposure from 3,900 tons of HAP reduced
	Health effects of ozone exposure from 300,000 tons of methane	Health effects of ozone exposure from 510,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the additional benefit estimates range from $160 million to $950 million in 2020 and $320 million to $1.8 billion in 2025 for Option 2, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

Table 1-4 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$420 million	$840 million
Total Costs[2]	$490 million	$880 million
Net Benefits[3]	-$75 million	-$38 million
Non-monetized Benefits	Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 160,00 tons of VOC reduced Health effects of HAP exposure from 2,400 tons of HAP reduced Health effects of ozone exposure from 350,000 tons of methane Visibility impairment Vegetation effects	Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 230,000 tons of VOC reduced Health effects of HAP exposure from 5,000 tons of HAP reduced Health effects of ozone exposure from 610,000 tons of methane Visibility impairment Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the additional benefit estimates range from $190 million to $1.1 billion in 2020 and $390 million to $2.2 billion in 2025 for this more stringent option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 8 million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

1.5 Summary of NSPS Impacts Changes from the Proposal RIA

This section summarizes major changes from the proposal version of the RIA. These changes were a result of revised assumptions and technical factors, as well as changes in the rule itself from proposal. With respect to changes in the rule's provisions from proposal, we focus on changes that have an effect on estimates of emissions reductions, costs, and benefits.

Changes resulting from revised assumptions and technical factors include:

- **Annual Energy Outlook and National Energy Modeling System updates:** At proposal, the Energy Information Administration (EIA) 2014 Annual Energy Outlook (AEO) was used to derive projections of oil and natural gas well drilling activities. For this RIA, we used the 2015 AEO, the latest version available at the time of the signature of the rule. Section 3.4.2 presents a brief discussion comparing the 2014 and 2105 AEOs.

The EPA also updated the version of the NEMS model from 2014 to 2015 to develop the energy markets impacts presented in Section 6.2 of this RIA.

- **EPA Greenhouse Gas Inventory updates:** The EPA updated the unit-level cost and emissions analyses where possible to reflect recent updates to the Greenhouse Gas Inventory. In particular, data from the Greenhouse Gas Reporting program and the Greenhouse Gas Inventory was used to update the equipment and component counts and potential emissions of the model plants for fugitive emissions.
- **Revised first year of regulatory program:** At proposal, 2020 was assumed to represent a single year of potential impacts. However, NSPS-affected facilities are facilities that are new or modified since the proposal in September 2015. In this final RIA, affected facilities in 2020 are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. As a result, the years of analysis in this RIA are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period. This methodological change results in a higher estimate of the number of affected facilities than at proposal and better represents the impacts of the rule.
- **New hydraulically fractured oil well completions with insufficient pressure to implement REC required to combust completions emissions:** Using the formula estimated to identify hydraulically fractured well completions that would not have sufficient pressure to perform a REC, approximately 40 percent of oil well completions that would otherwise be required to perform a REC would be required to combust emissions rather than implement a REC. The overall proportion of completions that are assumed to be feasible to REC remains unchanged from the proposal analysis at 50 percent. More detailed discussion is presented in a technical memorandum on this subject in the docket.[6]
- **Revised unit-level emissions and cost estimates:** The EPA revised the cost of control esimates for fugitive emissions monitoring and pneumatic pumps based on information provided by commenters.
- **Revised approach to projecting affected facilities from historical activity data:** Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years.

The changes in the rules requirements that affect emissions, cost, and benefit estimates include:

- **Fugitive emissions**: The EPA proposed to exclude low production well sites (e.g., well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for the collection of fugitive emissions components at well sites. Based on

[6] [Placeholder for title of low pressure well eequation technical memo]

analysis in response to comments, the EPA is finalizing the requirement that low production well sites are regulated under a monitoring and repair standard based on semiannual monitoring. With respect to fugitive emissions at compressor stations, based on analysis in response to comments, the EPA is finalizing the requirement to implement the fugitives program at compressor stations on a quarterly basis, as opposed to the proposed semiannual (twice per year) basis.

- **Hydraulically fractured oil well completions**: For the final rule, the EPA refined requirements that require wells that are not low GOR, low pressure, or exploration/delineation wells to have a separator on site during completion flowback. Wells with low GOR (less than 300 scf/of gas per stock barrel of oil produced) are still excluded from well completion requirements, but, unlike at proposal, they are considered affected facilities and their exclusion from requirements is provided the owner or operator maintains records of the low GOR certification, and submit a claim signed by the certifying official.
- **Pneumatic pumps**: The EPA changed the definition of an affected pneumatic pump facility to include only natural gas driven pumps in order to incentivize the use of lower emitting alternatives. The EPA also exempted chemical injection pumps and portable or temporary pumps from control requirements.

1.6 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents a comparison of benefits and costs. Section 6 presents energy markets impact, employment impact, and small entity impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS require controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the final NSPS.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2014, the Energy Information Administration (EIA) estimates that about 515,000 producing natural gas wells are operating in the U.S. The latest available information from EIA indicates that there were about 536,000 producing oil wells in the U.S. as of 2011. Domestic dry natural gas production was 25.7 trillion cubic feet (tcf) in 2014, the highest annual production level in U.S. history. The leading five natural gas producing states in 2014 were Texas, Pennsylvania, Oklahoma, Louisiana and Wyoming. Domestic crude oil production in 2014 was 3,200 million barrels (bbl), the highest annual level in the U.S. since 1991. The leading five crude oil producing states in 2014 were Texas, North Dakota, California, Alaska, and Oklahoma.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the NSPS. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analyses in this RIA. The Industry Profile relies heavily on background material from the EPA's "Economic Analysis of Air Pollution Regulations: Oil and

Natural Gas Production" (1996), the EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000), and the EPA's "Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry" (2012).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and the natural gas as well as the reservoir characteristics are likely to be different across all reservoirs.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another method to classify hydrocarbons, including crude oil, is through the measurement of API gravity. API gravity is a weight per-unit of volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with an API gravity of 20^o or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has an API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase may be referred to as live crudes. Live crudes contain entrained or dissolved gases that may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist in a gaseous phase or in a solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as a wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas is classified as acid, sour or sweet. Acid gas contains CO_2 and/or H_2S, where the concentration of H_2S is below the threshold to be classified as sour. Acid gas may contain other contaminants. Natural gas is classified as sour when it contains an H_2S concentration of greater than 0.25 grains per 100 standard cubic feet. Sour gas may also contain other contaminants. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening, most commonly performed through amine treating. A majority of total onshore natural gas production and nearly all offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^{o} or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either well completion if hydrocarbons are found in sufficient quantities, or to abandonment otherwise.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper, sections of drill pipe are added. A mix of fluids called drilling mud are released down into the drill pipe, which then push up the walls of the well bore, removing drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out (“blowing out”). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse, to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore allowing more oil or natural gas to move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2013). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant, a mixture of sand and other materials, is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because the well is usually drilled into the bottom, oil-heavy portion of a formation to recover most of the liquid first, with the natural gas cap sitting on top. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). When the well lacks enough pressure itself to drive the resource to the surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock, sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2013). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional oil and natural gas resource types relevant for this rule include:

- **Shale Oil and Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2013).
- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2013).
- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

As natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems. Natural gas conditioning is the process of removing impurities from the gas stream so it is of sufficient quality to pass through transportation systems and to be used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline.

One concern in natural gas processing is posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquid at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid desiccant, a solid desiccant, or refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract water molecules. The solids can be regenerated by heating them above the boiling point of water and then be reused as well. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

The most significant impurity in natural gas is H_2S, which may or may not be contained in natural gas. H_2S is toxic and potentially fatal, at certain concentrations, to humans and it is corrosive to pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Sweetening, the procedure in which H_2S and sometimes CO_2 are removed from the gas stream, is most commonly performed using amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with H_2S and separate it from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to increase pressure to improve the movement of natural gas through transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 *Domestic Proved Reserves*

Table 2-1 shows crude oil and dry natural gas proved reserves, unproved reserves, and total technically recoverable resources as of 2009. The EIA[7] defines these concepts as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.
- **Unproved resources:** additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology.
- **Total technically recoverable resources:** resources that are producible using current technology without reference to the economic viability of production.

According to the EIA, dry natural gas is consumer-grade natural gas. The dry natural gas volumes reported in Table 2-1 reflect the amount of gas remaining after the liquefiable portion and any non-hydrocarbon gases that render it unmarketable have been removed from the natural gas. The sum of proved reserves and unproved reserves equal the total technically recoverable resources. As seen in Table 2-1, as of 2009, proved domestic crude oil reserves accounted for about 10 percent of the total technically recoverable crude oil resources.

Total proved natural gas reserves, accounted for about 12 percent of the total technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and in offshore areas. While dry natural gas proved reserves were estimated at 272.5 tcf in 2009, wet natural gas reserves were estimated at 283.9 tcf. Of the 283.9 tcf, 250.5 tcf (about 88 percent) were considered to be wet non-associated natural gas, while 33.3 tcf (about 12 percent) were considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas, according to EIA, is natural gas that occurs in crude oil reservoirs as free natural gas or in solution with crude oil.

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[7] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2009

Region	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion barrels)			
48 States Onshore	14.2	112.6	126.7
48 States Offshore	4.6	50.3	54.8
Alaska	3.6	35.0	38.6
Total U.S.	22.3	197.9	220.2
Dry Natural Gas (trillion cubic feet)			
Conventionally Reservoired Fields	105.5	904.0	1,009.5
48 States Onshore [1]	81.4	369.7	451.1
48 States Offshore	15.0	262.6	277.6
Alaska	9.1	271.7	280.8
Tight Gas, Shale Gas and Coalbed Methane	167.1	1,026.7	1,193.8
Total U.S.	272.5	1,930.7	2,203.3

Source: U.S. Energy Information Administration, **Annual Energy Review 2012.** Totals may not sum due to independent rounding.

[1] Includes associated-dissolved natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2014. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. Cumulative production is the accumulated crude oil or dry natural gas that has been produced over time. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources. Annual production (the difference in cumulate production over one year) as a percentage of proved reserves has declined over time for both crude oil and natural gas from around 11 percent in the early 1990s to between 8 and 10 percent over the period from 2006 to 2014 for crude oil and from about 10 percent during the early 1990s to between 7 and 9 percent from 2006 to 2014 for natural gas.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1990-2014

	Crude Oil and Lease Condensate (million barrels)			Dry Natural Gas (Billion Cubic Feet or bcf)		
	Cumulative Production	**Proved Reserves**	**Proved Ult. Recovery**	**Cumulative Production**	**Proved Reserves**	**Proved Ult. Recovery**
1990	158,175	26,254	184,429	744,546	169,346	913,892
1991	160,882	24,682	185,564	762,244	167,062	929,306
1992	163,507	23,745	187,252	780,084	165,015	945,099
1993	166,006	22,957	188,963	798,179	162,415	960,594
1994	168,437	22,457	190,894	817,000	163,837	980,837
1995	170,831	22,351	193,182	835,599	165,146	1,000,745
1996	173,197	22,017	195,214	854,453	166,474	1,020,927
1997	175,552	22,546	198,098	873,355	167,223	1,040,578
1998	177,834	21,034	198,868	892,379	164,041	1,056,420
1999	179,981	21,765	201,746	911,211	167,406	1,078,617
2000	182,112	22,045	204,157	930,393	177,427	1,107,820
2001	184,229	22,446	206,675	950,009	183,460	1,133,469
2002	186,326	22,677	209,003	968,937	186,946	1,155,883
2003	188,388	21,891	210,279	988,036	189,044	1,177,080
2004	190,379	21,371	211,750	1,006,627	192,513	1,199,140
2005	192,270	21,757	214,027	1,024,677	204,385	1,229,062
2006	194,127	20,972	215,099	1,043,181	211,085	1,254,266
2007	195,981	21,317	217,298	1,062,447	237,726	1,300,173
2008	197,811	19,121	216,932	1,082,605	244,656	1,327,261
2009	199,765	20,682	220,447	1,103,229	272,509	1,375,738
2010	201,764	23,267	225,031	1,124,545	304,625	1,429,170
2011	203,822	26,544	230,366	1,147,447	334,067	1,481,514
2012	206,192	30,529	236,721	1,171,480	308,036	1,479,516
2013	208,913	33,371	242,284	1,195,685	338,264	1,533,949
2014	212,092	36,385	248,477	1,221,414	368,704	1,590,118

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17.
<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>. Accessed January 15, 2016.
Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.
<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.
Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.
<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.
Note: Cumulative Crude Oil Production includes Crude Oil plus Lease Condensate Production.
Note: The EIA reports Proved Reserves for Crude Oil and Proved Reserves for Crude Oil plus Lease Condensate separately. We have reported Proved Reserves for Crude Oil here.

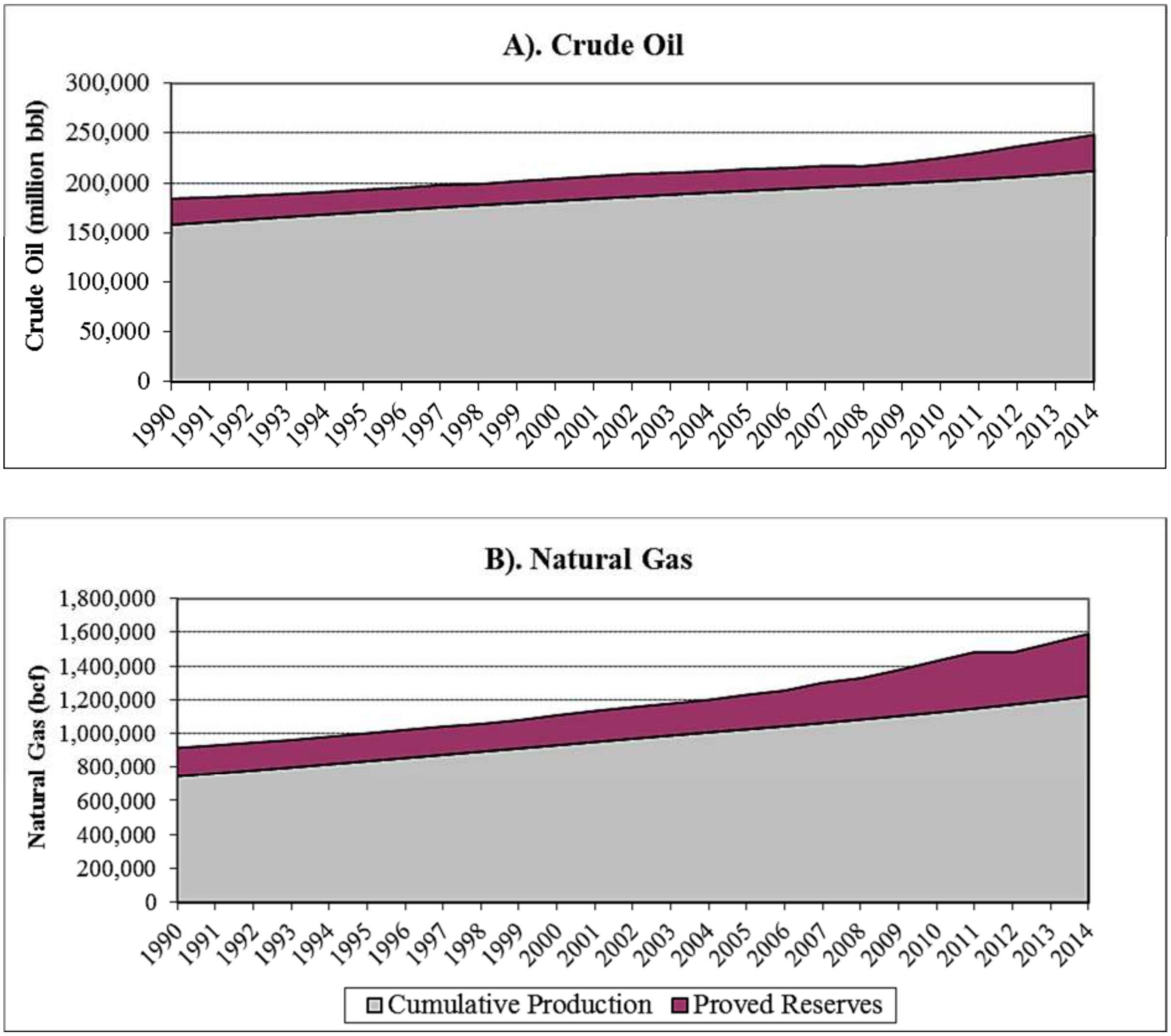

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17. <http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>. Accessed January 15, 2016.
Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014. <http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.
Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production. <http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2014. Five areas currently account for 79 percent of total proved reserves of crude oil in the U.S., led by Texas and followed by North Dakota, U.S. Federal Offshore, Alaska, and California. The top five states in terms of proved reserves of natural gas, Texas, Pennsylvania, Oklahoma, West Virginia, and Wyoming, account for about 67 percent of the U.S. total proved natural gas reserves.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2013

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (% of total)	Dry Natural Gas (% of total)
Alabama	66	2,036	0.2	0.6
Alaska	2,855	6,745	7.8	1.8
Arkansas	65	12,789	0.2	3.5
California	2,854	2,107	7.8	0.6
Colorado	1,200	20,851	3.3	5.7
Florida	70	0	0.2	0.0
Kansas	414	4,359	1.1	1.2
Kentucky	16	1,611	0.0	0.4
Louisiana	534	22,975	1.5	6.2
Michigan	53	1,845	0.1	0.5
Miscellaneous States **	84	2,976	0.2	0.8
Mississippi	230	558	0.6	0.2
Montana	444	667	1.2	0.2
New Mexico	1,476	15,283	4.1	4.1
New York	*	143	*	0.0
North Dakota	6,043	6,034	16.6	1.6
Ohio	78	6,723	0.2	1.8
Oklahoma	1,241	31,778	3.4	8.6
Pennsylvania	22	59,873	0.1	16.2
Texas	12,272	97,154	33.7	26.4
U.S. Federal Offshore	4,849	8,527	13.3	2.3
Utah	555	6,685	1.5	1.8
West Virginia	11	29,432	0.0	8.0
Wyoming	953	27,553	2.6	7.5
Total Proved Reserves	**36,385**	**368,704**	**100.0**	**100.0**

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas Proved Reserves, 2014. Table 7 and Table 17.
<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>. Accessed January 15, 2016.
Total may not sum due to independent rounding.
* New York crude oil reserves are included in miscellaneous states
**Miscellaneous for crude oil includes Arizona, Idaho, Missouri, Nevada, New York, South Dakota, Tennessee & Virginia as well as Illinois, Indiana, and Nebraska.
**Miscellaneous for dry natural gas includes Arizona, Idaho, Illinois, Indiana, Maryland, Missouri, Nebraska, Oregon, South Dakota & Tennessee as well as Virginia.

2.4.2 Domestic Production

Domestic oil production was in a state of decline that began in 1970 and continued to a low point in 2008. As of 2014, domestic oil production has recovered to the highest levels since 1991. Table 2-4 shows U.S. production in 2014 at 3,179 million bbl per year.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price, 1990-2014

	Total Production (million barrels)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	US Average First Purchase Price/Barrel (nominal dollars)	US Average First Purchase Price/Barrel (2012 dollars)
1990	2,685	602	4,460	20.03	31.56
1991	2,707	614	4,409	16.54	25.22
1992	2,625	594	4,419	15.99	23.84
1993	2,499	584	4,279	14.25	20.75
1994	2,431	582	4,178	13.19	18.81
1995	2,394	574	4,171	14.62	20.42
1996	2,366	574	4,122	18.46	25.32
1997	2,355	573	4,110	17.23	23.24
1998	2,282	562	4,060	10.87	14.50
1999	2,147	546	3,932	15.56	20.45
2000	2,131	534	3,990	26.72	34.33
2001	2,118	530	3,995	21.84	27.44
2002	2,097	529	3,963	22.51	27.85
2003	2,062	513	4,019	27.56	33.43
2004	1,991	510	3,905	36.77	43.41
2005	1,891	498	3,798	50.28	57.51
2006	1,857	497	3,737	59.69	66.24
2007	1,853	500	3,706	66.52	71.90
2008	1,830	526	3,479	94.04	99.69
2009	1,954	526	3,715	56.35	59.29
2010	1,999	520	3,844	74.71	77.66
2011	2,058	536	3,840	95.73	97.50
2012	2,370	N/A	N/A	94.52	94.52
2013	2,721	N/A	N/A	95.99	94.45
2014	3,179	N/A	N/A	87.39	84.60

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.
<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.
Source: U.S. Energy Information Administration (U.S. EIA). U.S. Crude Oil First Purchase Price.
<https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f000000__3&f=a>. Accessed on January 22, 2016.
Source: Federal Reserve Bank of St. Louis. Economic Research. Gross Domestic Product: Implicit Price Deflator.
<https://research.stlouisfed.org/fred2/series/GDPDEF>. Accessed February 3, 2016.
Note: First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. Prices adjusted using GDP Implicit Price Deflator.
Note: Total Production includes Crude Oil plus Lease Condensate Production.

Average well productivity has also generally decreased since 1990 (Table 2-4 and Figure 2-2), though there are signs of a slight rebounding starting around 2008. These overall production and productivity decreases are in spite of the fact that average first purchase prices have generally shown an increasing trend with some decline in 2014.

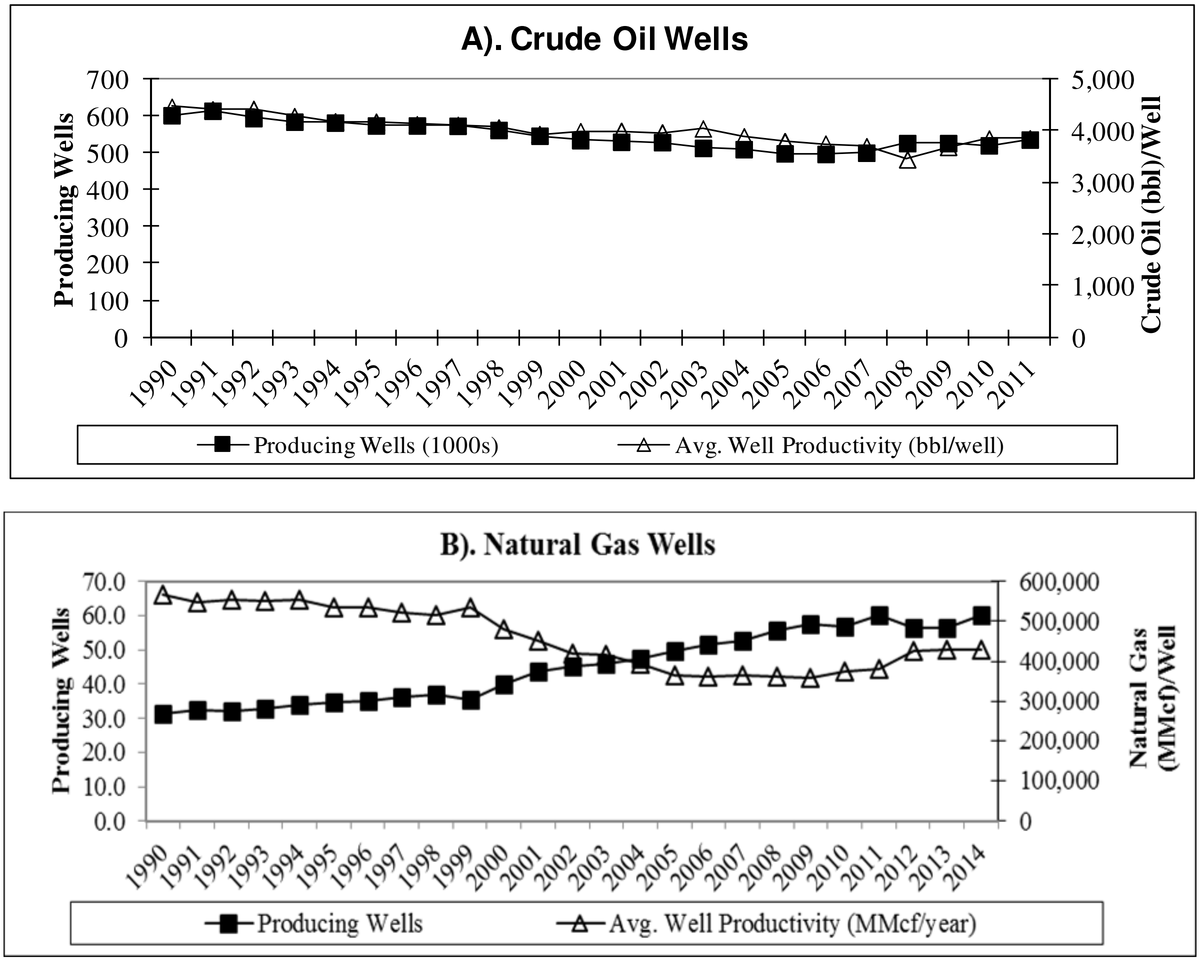

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2014.
Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014. <http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.

Annual production of natural gas from natural gas wells has increased more than 8000 bcf from the 1990 to 2014 (Table 2-5). The number of wells producing natural gas has nearly doubled between 1990 and 2014 (Figure 2-2B). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies. Average well productivity has shown slight improvements since 2009.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2014

	Natural Gas Gross Withdrawals (Billion Cubic Feet)		Natural Gas Well Productivity	
	Total	Dry Gas Production [1]	Producing Wells	Avg. Well Productivity Million Cubic Feet/Year)
1990	21,523	17,810	269,790	66.0
1991	21,750	17,698	276,987	63.9
1992	22,132	17,840	276,014	64.6
1993	22,726	18,095	282,152	64.1
1994	23,581	18,821	291,773	64.5
1995	23,744	18,599	298,541	62.3
1996	24,114	18,854	301,811	62.5
1997	24,213	18,902	310,971	60.8
1998	24,108	19,024	316,929	60.0
1999	23,823	18,832	302,421	62.3
2000	24,174	19,182	341,678	56.1
2001	24,501	19,616	373,304	52.5
2002	23,941	18,928	387,772	48.8
2003	24,119	19,099	393,327	48.6
2004	23,970	18,591	406,147	45.8
2005	23,457	18,051	425,887	42.4
2006	23,535	18,504	440,516	42.0
2007	24,664	19,266	452,945	42.5
2008	25,636	20,159	476,652	42.3
2009	26,057	20,624	493,100	41.8
2010	26,816	21,316	487,627	43.7
2011	28,479	22,902	514,637	44.5
2012	29,542	24,033	482,822	49.8
2013	29,523	24,206	484,994	49.9
2014	31,346	25,728	514,786	50.0

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014. <http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.
1 Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2010, crude oil well drilling showed significant increases, although the 1992-2004 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from the increasing trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2010 period. Like crude oil drilling, 2009 and 2010 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to a peak of 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in well drilling and completion. Similarly, average well depth has increased by an estimated 1,227 feet during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2010

	Wells Drilled					
Year	**Crude Oil**	**Natural Gas**	**Dry Holes**	**Total**	**Successful Wells (%)**	**Average Depth (ft)**
1990	12,445	11,126	8,496	32,067	75	4,881
1991	12,035	9,611	7,882	29,528	75	4,920
1992	9,019	8,305	6,284	23,608	75	5,202
1993	8,764	10,174	6,513	25,451	75	5,442
1994	7,001	9,739	5,515	22,255	77	5,795
1995	7,827	8,454	5,319	21,600	77	5,636
1996	8,760	9,539	5,587	23,886	79	5,617
1997	10,445	11,186	5,955	27,586	79	5,691
1998	6,979	11,127	4,805	22,911	80	5,755
1999	4,314	11,121	3,504	18,939	83	5,090
2000	8,090	17,051	4,146	29,287	86	4,961
2001	8,888	22,072	4,598	35,558	87	5,087
2002	6,775	17,342	3,754	27,871	87	5,232
2003	8,129	20,722	3,982	32,833	88	5,426
2004	8,789	24,186	4,082	37,057	89	5,547
2005	10,779	28,590	4,653	44,022	89	5,508
2006	13,385	32,838	5,206	51,429	90	5,613
2007	13,371	32,719	4,981	51,071	90	6,064
2008	16,633	32,246	5,423	54,302	90	5,964
2009*	11,190	18,088	3,525	32,803	90	6,202
2010*	15,753	16,696	4,162	36,611	89	6,108

Source: U.S. Energy Information Administration
* Average Depth values for 2009-2010 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009). As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low produced water to oil ratios compared to states like Illinois, Florida, Missouri, Indiana and Kansas.

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

Figure 2-3 shows the distribution of produced water management practices in 2007. More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. About one third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) was discharged into surface water when it met water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

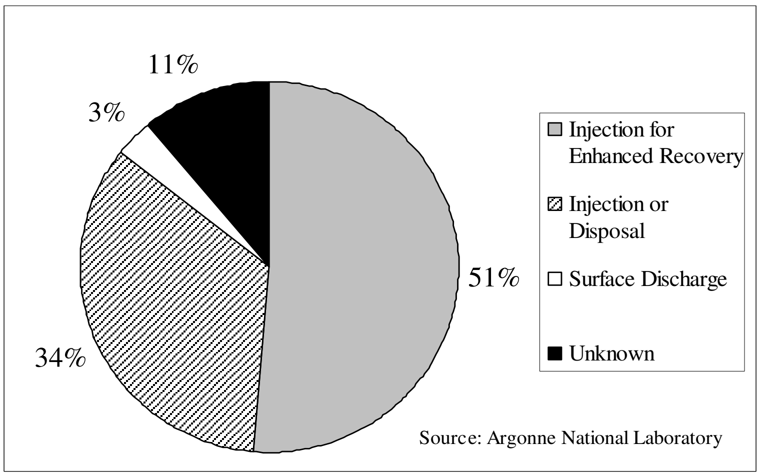

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage decreased during the 1990-2010 period, appearing to follow the downward supply trend shown in Table 2-4. Since 2010, total crude oil pipeline mileage has increased by over 12,000 miles (Table 2-8).

Table 2-8 splits natural gas pipelines into four types: distribution mains, distribution service, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites and deliver it directly to gas processing plants or compression stations which connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants and distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Mileage on the distribution side, distribution mains and distribution service, has increased while transmission pipeline and gathering line mileage has decreased. Since 2010, total natural gas pipeline has increased by over 61,000 miles**.**

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 2010-2014

	Natural Gas Pipelines (miles)					Crude Oil Pipelines (miles)
	Distribution mains	**Distribution Service**	**Transmission pipelines**	**Gathering lines**	**Total**	**Total**
2010	1,229,725	872,466	304,805	19,626	2,426,622	54,631
2011	1,238,947	881,955	305,058	19,350	2,445,310	56,100
2012	1,247,231	890,361	303,341	16,532	2,457,465	57,463
2013	1,255,145	894,283	302,827	17,369	2,469,624	61,087
2014	1,266,039	902,772	301,806	17,621	2,488,238	66,700

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Annual Report Mileage Summary Statistics*, available at <http://phmsa.dot.gov/pipeline/library/data-stats> as of January 4, 2016.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2012 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008, when total consumption basically leveled off as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the percentage of the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2012.

Table 2-9 Crude Oil Consumption by Sector, 1990-2012

	Total (million barrels)	Percent of Total			
		Residential and Commercial	Industrial	Transportation Sector	Electric Power
1990	6,178	7.3	25.1	64.3	3.3
1991	6,068	7.3	24.9	64.7	3.2
1992	6,209	7.1	26.1	64.3	2.6
1993	6,277	6.9	25.3	65.0	2.9
1994	6,439	6.6	26.0	64.8	2.6
1995	6,402	6.4	25.7	66.0	1.9
1996	6,627	6.7	26.1	65.2	2.0
1997	6,726	6.3	26.4	65.1	2.2
1998	6,837	5.7	25.4	65.8	3.1
1999	7,053	6.1	25.6	65.5	2.8
2000	6,984	4.6	25.1	67.6	2.6
2001	6,963	4.6	25.1	67.4	2.9
2002	6,990	4.2	25.2	68.3	2.2
2003	7,091	4.6	24.8	67.9	2.7
2004	7,399	4.4	25.3	67.7	2.6
2005	7,530	5.8	24.2	67.3	2.6
2006	7,506	5.0	24.8	68.9	1.4
2007	7,517	5.1	24.1	69.5	1.4
2008	7,095	5.5	23.0	70.4	1.1
2009	6,849	5.5	22.2	71.4	1.0
2010	6,994	5.2	22.8	71.0	0.9
2011	7,013	5.0	23.2	71.1	0.7
2012	6,902	5.0	23.4	71.1	0.5

Source: U.S. Energy Information Administration.

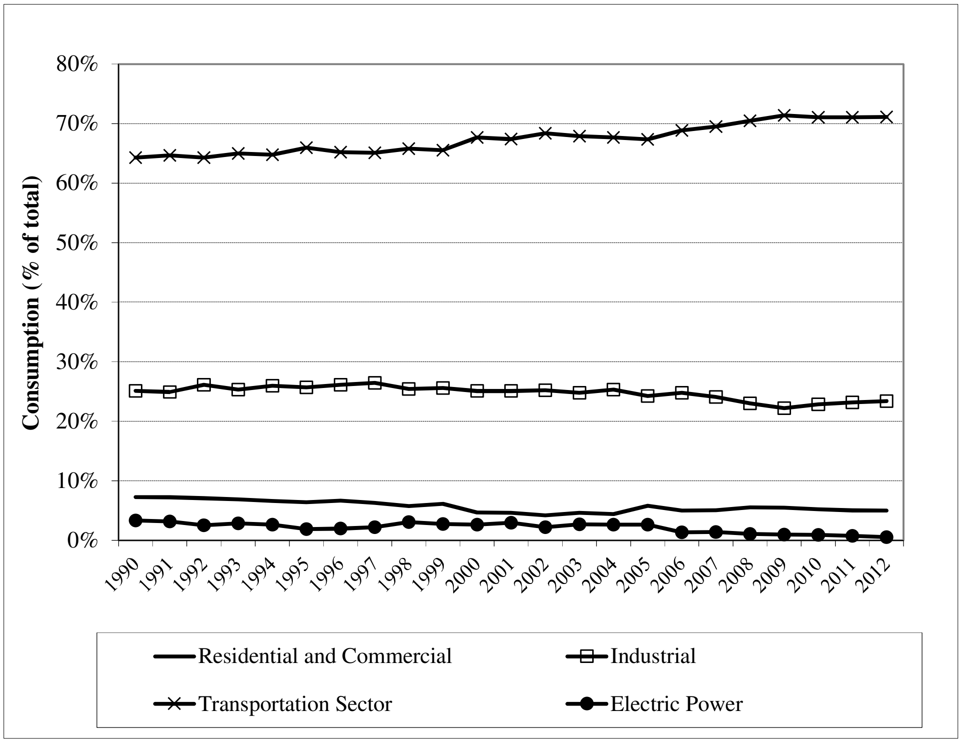

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2012

Natural gas consumption has increased over the last twenty years. From 1990 to 2014, total U.S. consumption increased by an average of about 1.6 percent per year (Table 2-10 and Figure 2-5). Over this period, the percentage of natural gas consumed by the industrial sector declined, whereas the percent of total natural gas used for electric power generation increased dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential sector demand has bounced around between about 23 and 19 percent, where the lower percentage of total demand falls mainly in the years post 2008 with slightly larger dip in 2012. Commercial sector demand hovered around 13 and 14 percent, also with a slight dip in 2012. The transportation sector has maintained a fairly constant consumption level of right around 3 percent between 1990 and 2014.

Table 2-10 Natural Gas Consumption by Sector, 1990-2014

		Percent of Total				
	Total (tcf)	Residential	Commercial	Industrial	Electric Power	Transportation
1990	19.17	22.9	13.7	43.1	16.9	3.4
1991	19.56	23.3	13.9	42.7	17.0	3.1
1992	20.23	23.2	13.9	43.0	17.0	2.9
1993	20.79	23.8	13.8	42.7	16.7	3.0
1994	21.25	22.8	13.6	42.0	18.4	3.2
1995	22.21	21.8	13.6	42.3	19.1	3.2
1996	22.61	23.2	14.0	42.8	16.8	3.2
1997	22.74	21.9	14.1	42.7	17.9	3.3
1998	22.25	20.3	13.5	42.7	20.6	2.9
1999	22.41	21.1	13.6	40.9	21.5	2.9
2000	23.33	21.4	13.6	39.8	22.3	2.8
2001	22.24	21.5	13.6	38.1	24.0	2.9
2002	23.03	21.2	13.7	37.5	24.6	3.0
2003	22.28	22.8	14.3	37.1	23.1	2.7
2004	22.40	21.7	14.0	37.3	24.4	2.6
2005	22.01	21.9	13.6	35.0	26.7	2.8
2006	21.70	20.1	13.1	35.3	28.7	2.8
2007	23.10	20.4	13.0	34.1	29.6	2.8
2008	23.28	21.0	13.5	33.9	28.6	2.9
2009	22.91	20.9	13.6	32.5	30.0	3.0
2010	24.09	19.9	12.9	33.7	30.7	2.9
2011	24.48	19.3	12.9	34.0	30.9	2.9
2012	25.54	16.2	11.3	33.8	35.7	3.0
2013	26.16	18.7	12.6	34.1	31.3	3.3
2014	26.69	19.1	13.0	34.2	30.5	3.3

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by Sector data. < http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-13-14>. Accessed February 3, 2016.
Note: Industrial Consumption is reported as Lease and Plant Fuel, Other Industrial: CHP, and Other Industrial: Non-CHP

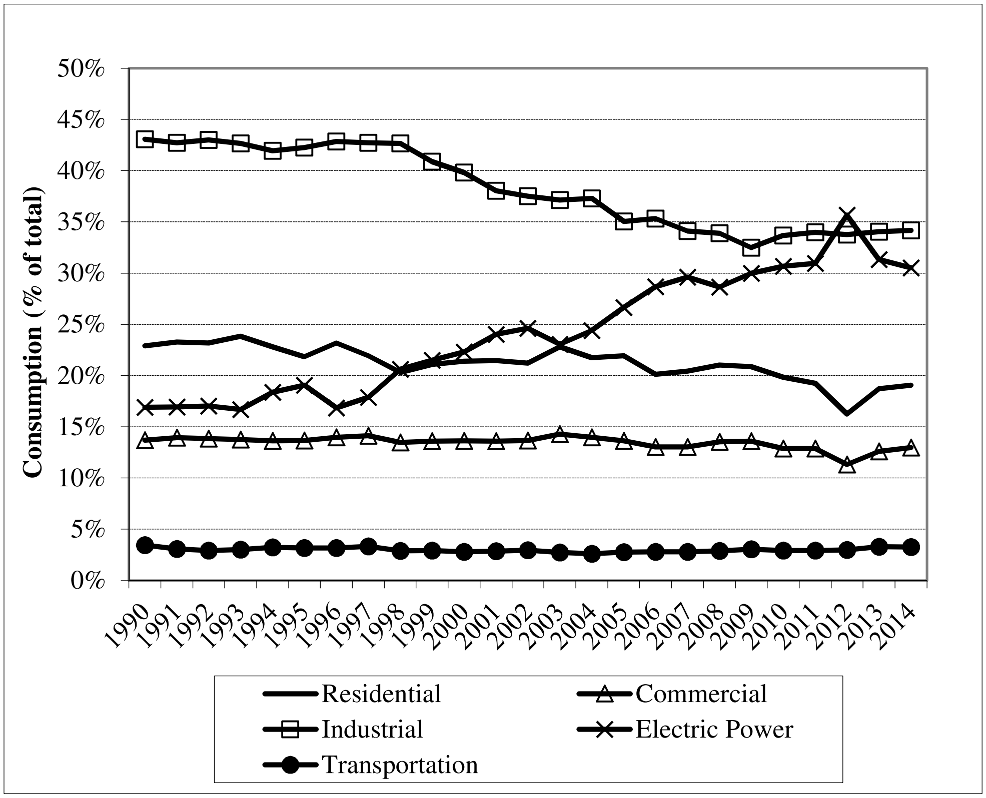

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2012

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by Sector data. < http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-13-14>. Accessed February 3, 2016.

2.4.4 International Trade

Until 2006, net trade of crude oil and refined petroleum products increased, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S. (Table 2-11). Since then, however, imports have been declining while exports have been rising, leading to significant declines in net trade or crude oil and petroleum products.

Table 2-11 Total Crude Oil and Petroleum Products Trade (Million Bbl), 1990-2014

	Imports			Exports			Net Imports		
	Crude Oil	Petroleum Products	Total	Crude Oil	Petroleum Products	Total	Crude Oil	Petroleum Products	Total
1990	2,151	775	2,926	40	273	313	2,112	502	2,614
1991	2,111	673	2,784	42	323	365	2,068	350	2,418
1992	2,226	661	2,887	32	315	348	2,194	345	2,539
1993	2,477	669	3,146	36	330	366	2,441	339	2,780
1994	2,578	706	3,284	36	308	344	2,542	398	2,940
1995	2,639	586	3,225	35	312	346	2,604	274	2,878
1996	2,748	721	3,469	40	319	359	2,708	403	3,110
1997	3,002	707	3,709	39	327	366	2,963	380	3,343
1998	3,178	731	3,908	40	305	345	3,137	426	3,564
1999	3,187	774	3,961	43	300	343	3,144	474	3,618
2000	3,320	874	4,194	18	362	381	3,301	512	3,813
2001	3,405	928	4,333	7	347	354	3,398	581	3,979
2002	3,336	872	4,209	3	356	359	3,333	517	3,849
2003	3,528	949	4,477	5	370	375	3,523	579	4,102
2004	3,692	1119	4,811	10	374	384	3,682	745	4,427
2005	3,696	1310	5,006	12	414	425	3,684	896	4,580
2006	3,693	1310	5,003	9	472	481	3,684	838	4,523
2007	3,661	1255	4,916	10	513	523	3,651	742	4,393
2008	3,581	1146	4,727	10	649	659	3,570	497	4,068
2009	3,290	977	4,267	16	723	739	3,274	255	3,528
2010	3,363	942	4,305	15	843	859	3,348	98	3,446
2011	3,261	913	4,174	17	1073	1,090	3,244	-160	3,084
2012	3,121	758	3,879	25	1148	1,173	3,096	-390	2,706
2013	2,821	777	3,598	49	1273	1,322	2,773	-496	2,277
2014	2,681	692	3,373	128	1396	1,524	2,552	-704	1,849

Sources: U.S. Energy Information Administration (U.S. EIA). U.S. Imports by Country of Origin. <http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_a.htm>. Accessed January 22, 2016.
U.S. Energy Information Administration (U.S. EIA). U.S. Exports by Destination. <https://www.eia.gov/dnav/pet/pet_move_expc_a_EP00_EEX_mbbl_a.htm>. Accessed January 22, 2016.

From 1990 to 2007, natural gas imports have increased steadily in both volume and percentage terms (Table 2-12). Imported natural gas constituted a lower percentage of domestic natural gas consumption from 2007 through 2014 compared to earlier years. Until recent years, industry analysts have forecasted that LNG imports would continue to grow as a percentage of U.S. consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, is reducing the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2014

	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.4
1998	3,152	159	2,993	13.4
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.8
2004	4,259	854	3,404	15.5
2005	4,341	729	3,612	16.7
2006	4,186	724	3,462	16.2
2007	4,608	822	3,785	16.6
2008	3,984	963	3,021	13.2
2009	3,751	1,072	2,679	11.7
2010	3,741	1,137	2,604	10.8
2011	3,468	1,506	1,962	8.0
2012	3,138	1,619	1,519	5.9
2013	2,883	1,572	1,311	5.0%
2014	2,695	1,514	1,181	4.4%

Source: U.S. Energy Information Administration (U.S. EIA). U.S. Natural Gas Imports & Exports by State. <https://www.eia.gov/dnav/ng/NG_MOVE_STATE_DCU_NUS_A.htm>. Accessed January 21, 2016.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the most current forecast information available from the EIA, the 2014 and 2015 Annual Energy Outlook. The 2014 and 2015 Annual Energy Outlook was produced using the National Energy Modeling System (NEMS), which the EPA uses to analyze the impacts of the final NSPS on the national economy as is discussed in detail in Section 7.

Table 2-13 present forecasts of successful wells drilled in the U.S. from 2010 to 2040. Crude oil well forecasts for the lower 48 states show a rise up to the year 2025 then a gradual decline until 2040. Meanwhile, the forecast shows an increase in natural gas drilling in the lower 48 states from the present to 2040, more than doubling during this 25-year period.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2040

	Totals	
Year	**Crude Oil**	**Natural Gas**
2010	19,316	19,056
2011	23,048	14,355
2012	26,749	11,011
2013	25,248	11,507
2014	22,274	14,099
2015	22,706	14,076
2016	22,552	15,004
2017	22,355	15,773
2018	22,421	18,340
2019	22,525	20,188
2020	24,765	20,396
2021	25,017	23,427
2022	25,400	24,945
2023	25,981	24,999
2024	26,917	24,745
2025	27,763	24,831
2026	26,258	25,445
2027	25,830	26,895
2028	25,270	28,341
2029	24,801	29,019
2030	24,310	28,799
2031	23,972	29,681
2032	23,607	31,406
2033	23,283	31,749
2034	23,057	32,882
2035	22,740	33,278
2036	22,494	33,456
2037	22,343	33,536
2038	22,075	33,944
2039	21,911	34,001
2040	21,750	33,656

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2014.**

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and Figure 2-6 depicts these trends graphically. Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2012 to 2040, with an increase of 49 percent overall. This increment is smaller than the forecast increase in production from the lower 48 states during this period, 52 percent, showing production is forecast to grow more rapidly than reserves. In addition, Table 2-14 shows average wellhead prices increasing more than 41 percent from 2012 to 2040, from $96.38 per barrel to $136.13 per barrel in 2013 dollar terms.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2012-2040

	Domestic Production (million bbls)								
	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Other Crude Supply	Net Imports	Total Crude Supply	Lower 48 End of Year Reserves (million bbls)	Lower 48 Average Wellhead Price (2013 dollars per barrel)
2012	2,373	1,678	503	192	16	3,088	5,476	30,051	96.38
2013	2,715	2,032	495	188	97	2,773	5,584	29,441	96.51
2014	3,151	2,422	549	180	47	2,563	5,761	31,131	90.37
2015	3,404	2,640	599	164	78	2,343	5,826	31,966	53.49
2016	3,486	2,691	637	158	51	2,307	5,845	33,549	68.35
2017	3,651	2,790	699	162	0	2,156	5,807	34,747	72.44
2018	3,786	2,865	757	164	0	2,055	5,841	35,948	72.34
2019	3,861	2,906	797	158	0	1,995	5,857	37,002	73.79
2020	3,870	2,933	785	153	0	2,012	5,882	37,403	75.16
2021	3,837	2,923	770	145	0	2,086	5,924	37,760	76.97
2022	3,812	2,918	757	137	0	2,131	5,943	38,137	79.27
2023	3,785	2,918	738	129	0	2,181	5,966	38,605	81.68
2024	3,786	2,932	732	122	0	2,189	5,975	39,066	84.11
2025	3,752	2,924	712	116	0	2,222	5,974	39,389	86.57
2026	3,692	2,869	712	110	0	2,285	5,977	39,908	89.27
2027	3,682	2,850	729	103	0	2,300	5,982	40,633	92.03
2028	3,700	2,837	766	97	0	2,291	5,991	41,497	94.89
2029	3,681	2,802	787	92	0	2,321	6,002	42,109	97.86
2030	3,665	2,773	805	86	0	2,349	6,014	42,593	100.92
2031	3,573	2,688	804	82	0	2,454	6,027	42,708	104.19
2032	3,495	2,622	795	77	0	2,533	6,028	42,665	107.44
2033	3,448	2,587	787	73	0	2,604	6,052	42,795	110.82
2034	3,424	2,578	777	69	0	2,657	6,081	43,066	113.86
2035	3,425	2,580	780	66	0	2,683	6,108	43,425	117.20
2036	3,407	2,571	773	62	0	2,723	6,130	43,609	120.77
2037	3,404	2,557	766	81	0	2,752	6,156	43,808	124.33
2038	3,422	2,541	774	107	0	2,748	6,170	44,124	128.36
2039	3,420	2,534	761	126	0	2,766	6,187	44,234	132.37
2040	3,440	2,527	790	123	0	2,768	6,208	44,779	136.13

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 25, 2016.

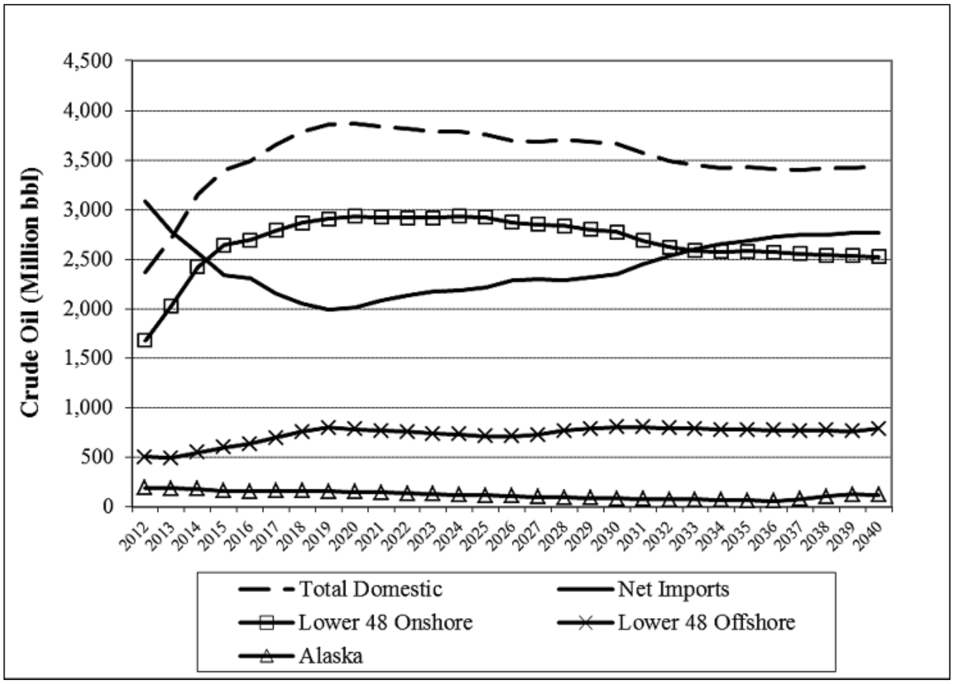

Figure 2-6 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040
Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 25, 2016.

Table 2-15 shows domestic natural gas production is forecast to increase until 2040. Meanwhile, imports of natural gas via pipeline are eliminated during the forecast period, from 1.37 tcf in 2012 to -2.33 tcf in 2040. Imports of LNG are also expected to be eliminated during the forecast period, from 0.15 tcf in 2012 to -3.29 tcf in 2040. Dry Gas Production increases about 47 percent, from 24.06 tcf in 2012 to 35.45 in 2040. Total supply increases about 17 percent, from 25.64 tcf in 2012 to 29.90 tcf in 2040.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price 2012-2040

	Domestic Production (tcf)		Net Imports (tcf)				
	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves (tcf)	Average Henry Hub Spot Price (2013 dollars per million Btu)
2012	24.06	0.06	1.37	0.15	25.64	298.5	2.79
2013	24.40	0.05	1.20	0.09	25.75	293.2	3.73
2014	25.57	0.06	1.09	0.05	26.77	299.0	4.37
2015	26.43	0.06	0.83	-0.03	27.29	300.8	3.69
2016	27.30	0.06	0.58	-0.23	27.71	301.5	3.70
2017	27.18	0.06	0.23	-0.69	26.78	303.7	3.80
2018	27.68	0.06	-0.07	-1.05	26.62	305.5	4.21
2019	28.27	0.06	-0.29	-1.52	26.53	307.5	4.55
2020	28.82	0.06	-0.48	-2.08	26.33	308.9	4.88
2021	29.17	0.06	-0.58	-2.37	26.28	310.6	5.02
2022	29.53	0.06	-0.72	-2.49	26.39	312.1	5.09
2023	29.85	0.06	-0.83	-2.49	26.60	313.3	5.25
2024	30.17	0.06	-0.91	-2.49	26.84	314.7	5.35
2025	30.51	0.06	-1.01	-2.49	27.07	315.7	5.46
2026	30.78	0.06	-1.09	-2.49	27.27	316.8	5.67
2027	31.37	0.06	-1.21	-2.69	27.54	319.2	5.67
2028	31.94	0.06	-1.31	-2.89	27.80	322.2	5.67
2029	32.50	0.06	-1.41	-3.09	28.06	325.3	5.71
2030	33.01	0.06	-1.52	-3.29	28.27	328.7	5.69
2031	33.19	0.06	-1.60	-3.29	28.37	330.8	5.91
2032	33.40	0.06	-1.69	-3.29	28.49	332.7	6.09
2033	33.63	0.06	-1.77	-3.29	28.63	334.5	6.27
2034	33.84	0.06	-1.83	-3.29	28.79	336.5	6.45
2035	34.14	0.06	-1.90	-3.29	29.01	338.3	6.60
2036	34.46	0.06	-2.00	-3.29	29.24	339.9	6.76
2037	34.75	0.06	-2.09	-3.29	29.44	341.5	6.84
2038	35.04	0.06	-2.19	-3.29	29.62	343.3	7.02
2039	35.28	0.06	-2.30	-3.29	29.75	344.3	7.38
2040	35.45	0.06	-2.33	-3.29	29.90	345.2	7.85

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to 2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 19, 2016

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-7).

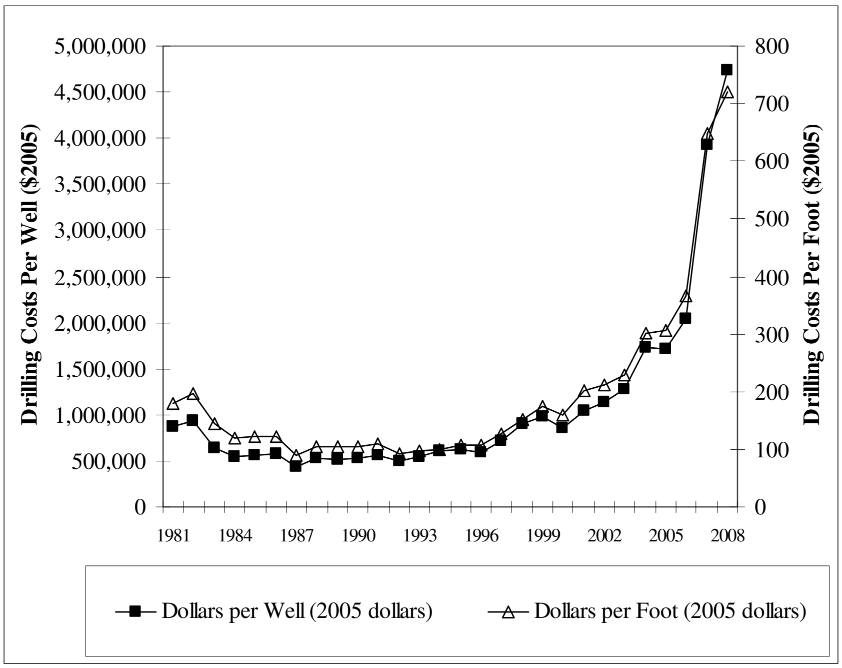

Figure 2-7 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by the EIA add an additional level of detail to drilling costs, in that finding costs incorporate the broader costs associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. The EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-8 shows average domestic onshore, offshore and foreign finding costs for the sample of U.S. firms in the EIA's Financial Reporting System (FRS) database from 1981 to 2009. The costs are reported in 2009 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore, offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore, offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-7 and finding costs in Figure 2-8 present similar trends overall.

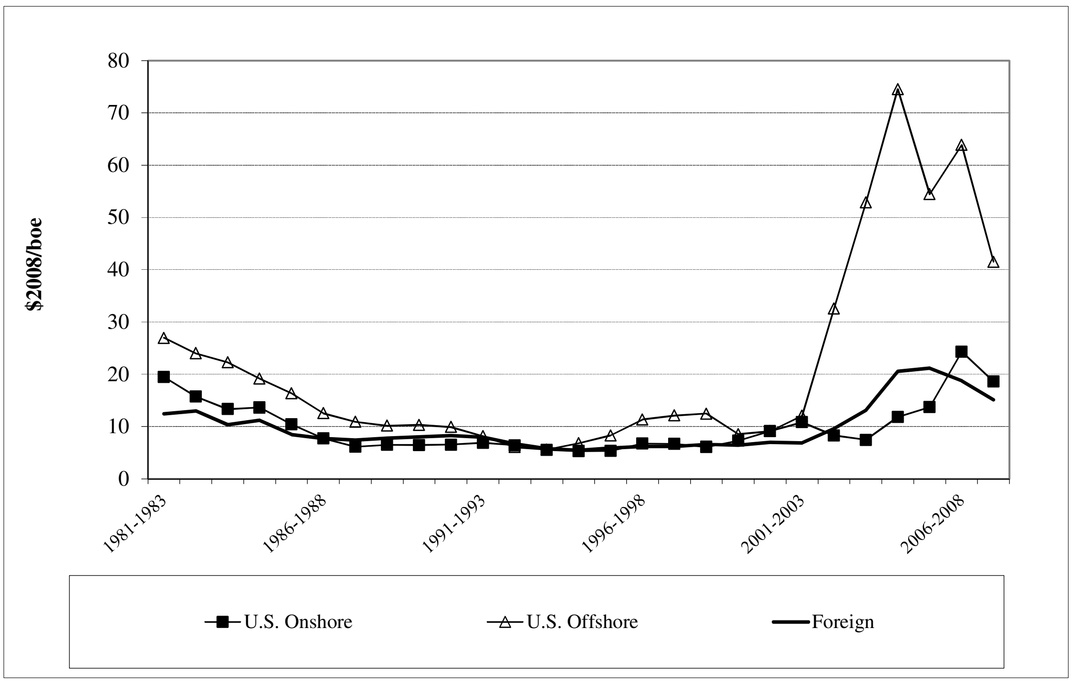

Figure 2-8 Finding Costs for FRS Companies, 1981-2009
Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy Producers, 2009.Figure 17 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January 19, 2016.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. The EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, the EIA reports average lifting costs for FRS firms in 2009 dollars on a barrel of oil equivalent basis.

Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-9 depicts direct lifting cost trends from 1981 to 2009 for domestic and foreign production.

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrel of oil equivalent between 1981 and 1985, then declined almost $5 per barrel of oil equivalent by 2000. From 2000 to 2009, domestic lifting costs increased sharply, just over $8 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, with foreign lifting costs lower than domestic costs during this period. After 1991, foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2009.

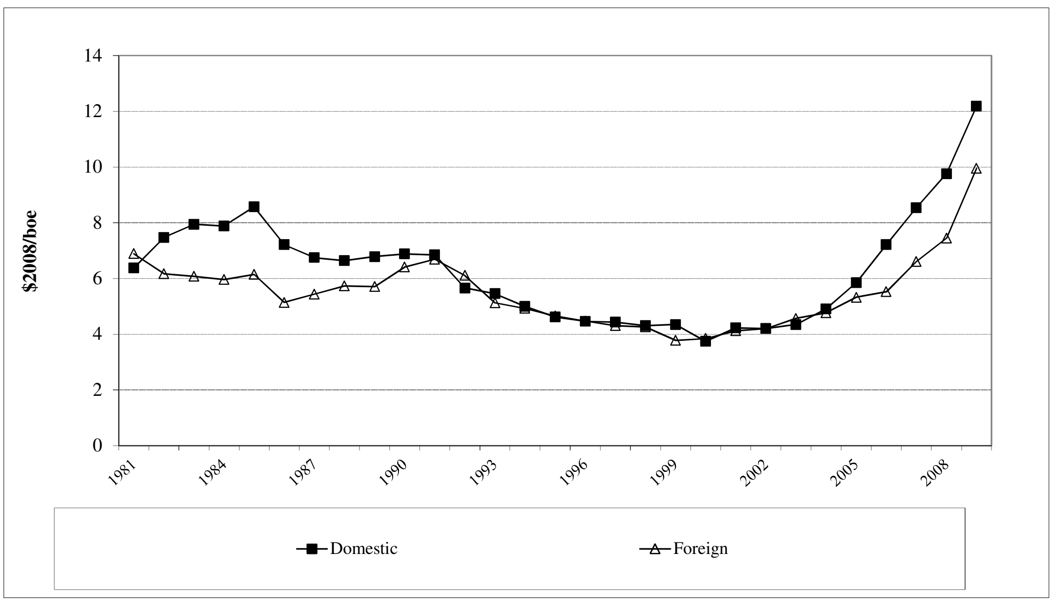

Figure 2-9 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-year Running Average)

Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy Producers, 2009.Figure 15 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January 19, 2016.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[8], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-10 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, but operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s. Oil costs and prices again generally rose between 2000 and 2009, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

[8] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

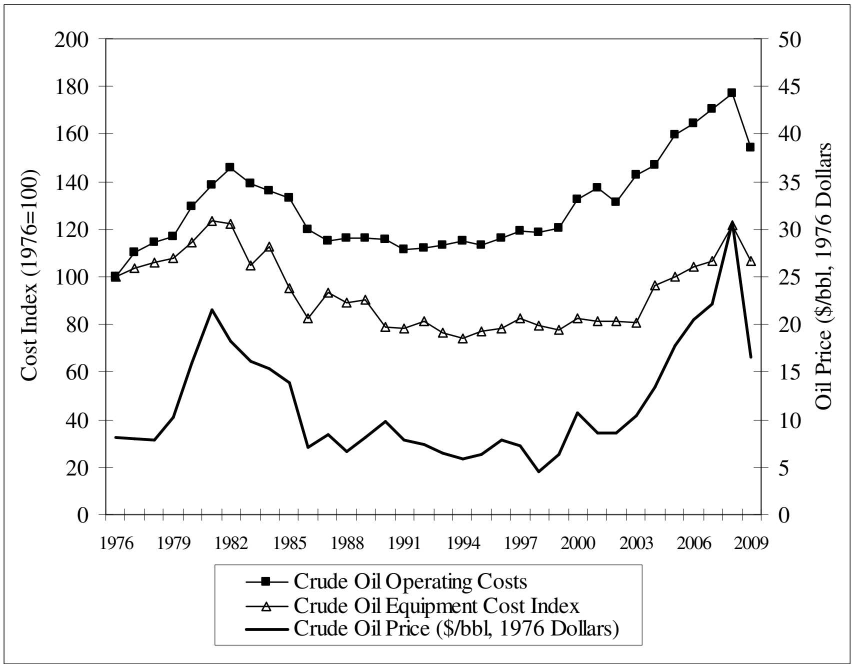

Figure 2-10 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009[9]

Source: U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

Figure 2-11 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid-1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

[9] The last release date for the EIA's *Oil and Gas Lease Equipment and Operating Costs* analysis was September 2010. Updates have been discontinued.

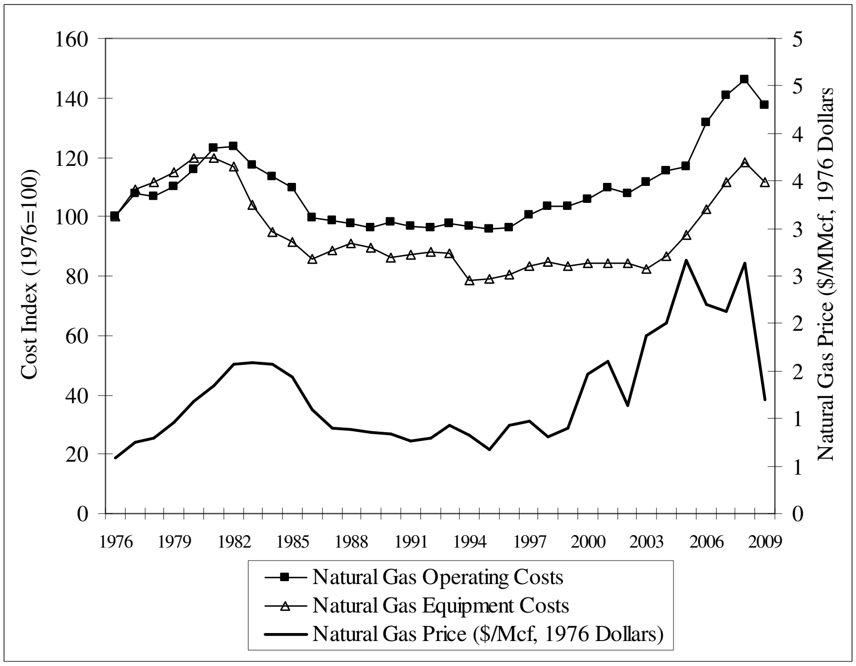

Figure 2-11 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Source: U.S. Energy Information Administration. “Oil and Gas Lease Equipment and Operating Costs 1994 through 2009.” September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plants and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 54 percent of domestic crude oil, 85 percent of domestic natural gas, and drill almost 95 percent of the wells in the U.S (IPAA, 2012-13). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected NAICS

As of 2012, there were 6,679 firms within the 211111 and 211112 NAICS codes, of which 6,551 (98 percent) were considered small entities (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for almost 61 percent of employment listed under these NAICS. The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 56 percent of employment. Within NAICS 486210, large firms compose about 43 percent of total firms and about 95 percent of employment.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard** (Employees or Annual Receipts)	*Small Firms	*Large Firms	*Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500[1]	6,444	92	6,536
211112	Natural Gas Liquid Extraction	500[2]	107	36	143
213111	Drilling Oil and Gas Wells	500[3]	2,085	59	2,144
213112	Support Activities for Oil and Gas Operations	$38.5 million	8,750	127	8,877
486210	Pipeline Transportation of Natural Gas	$27.5 million	92	46	138
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	47,528	66,996	114,524
211112	Natural Gas Liquid Extraction	500	1,709	8,768	10,477
213111	Drilling Oil and Gas Wells	500	39,628	66,740	106,368
213112	Support Activities for Oil and Gas Operations	$38.5 million	126,523	145,834	272,357
486210	Pipeline Transportation of Natural Gas	$27.5 million	1,503	31,823	33,326

*These numbers are reported by Enterprise Employment Size <500 and 500+
Sources: U.S. Census Bureau. Statistics of U.S. Businesses. Accessed January 18, 2016.
U.S. Government Publishing Office. Electronic Code of Regulation, Title 13, Chapter 1, Part 121. Accessed January 18, 2016.
U.S. Small Business Administration, Office of Advocacy. 2014. Firm Size Data. Accessed January 5, 2016.
**The SBA size standards for some of the NAICS were updated in February, 2016.
1. Updated to 1,250 employees
2. Updated to 750 employees
3. Updated to 1,000 employees.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2014. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of about 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-2014

	Crude Petroleum and Natural Gas Extraction (NAICS 211111)	Natural Gas Liquid Extraction (NAICS 211112)	Drilling of Oil and Natural Gas Wells (NAICS 213111)	Support Activities for Oil and Gas Ops. (NAICS 213112)	Pipeline Trans. of Crude Oil (NAICS 486110)	Pipeline Trans. of Natural Gas (NAICS 486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	350,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539
2010	153,490	4,833	74,491	201,685	8,893	26,708	470,100
2011	164,900	5,835	87,272	241,490	8,959	27,320	535,776
2012	181,473	6,529	92,340	282,447	9,348	27,595	599,732
2013	189,804	6,928	93,261	296,891	10,059	26,981	623,924
2014	189,222	7,482	98,208	326,353	10,708	28,242	660,215

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014 , <http://data.bls.gov/cgi-bin/dsrv>. Accessed on January 19, 2016.

From 1990 to 2014, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry. Employees in the NAICS 211 codes earn the highest average wages in the oil and natural gas industry, while employees in the NAICS 213 codes have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2014 (2012 dollars)

	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	74,510	69,910	44,213	48,033	71,265	64,482	62,274
1991	76,016	70,026	45,614	49,601	72,311	68,260	63,916
1992	80,259	72,319	45,704	51,379	77,977	70,505	67,466
1993	81,252	72,271	47,508	52,674	76,481	70,810	67,765
1994	83,014	74,311	46,739	52,590	79,827	71,838	68,090
1995	85,381	70,906	48,485	53,319	82,756	75,453	69,667
1996	88,360	72,290	51,280	55,426	80,627	80,141	71,760
1997	94,353	83,408	54,780	58,370	82,343	86,898	75,390
1998	97,915	94,471	55,718	60,473	83,066	88,409	77,429
1999	103,283	93,896	57,242	62,786	86,666	99,165	83,007
2000	115,071	117,532	63,817	63,535	85,034	136,971	91,032
2001	116,471	116,567	64,822	64,328	87,404	128,302	89,458
2002	115,367	108,753	65,257	62,876	91,806	96,055	86,280
2003	116,216	118,377	64,125	64,398	91,831	96,154	86,755
2004	127,383	124,432	66,282	65,703	98,426	98,531	91,002
2005	133,983	134,481	74,521	70,786	96,951	95,061	95,074
2006	145,726	140,751	78,083	74,119	96,738	104,104	100,131
2007	143,333	140,394	86,745	76,134	101,563	111,528	101,771
2008	153,226	132,644	86,886	78,468	107,886	105,176	105,060
2009	141,818	131,569	85,894	74,614	106,237	106,647	102,241
2010	152,145	132,041	86,337	77,810	108,906	112,910	106,572
2011	156,107	120,995	91,928	81,479	114,764	116,320	108,914
2012	155,735	136,353	92,266	80,222	120,292	139,127	108,872
2013	152,884	122,618	92,610	80,405	116,055	116,460	106,881
2014	157,827	123,305	95,454	83,364	109,590	116,679	108,807

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014, annual wages per employee <http://www.bls.gov/cew/>. Accessed on January 21, 2016.

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasingly performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms. Typically, wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independent firms have to rely solely on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated.

Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, though now it has been reduced to the top 150. In 2014, 143 public companies are listed; in 2013 there were 139 firms.[10] The 2012 list contains four companies that were not on the list in the previous year. Table 2-19 lists selected statistics for the top 20 companies in 2014. The results presented in the table reflect a decline in U.S. oil prices.

Net income for the top 134 companies fell about 17.5% between 2013 and 2014 to about $74 billion. Revenues for these companies increased by about $6 billion from 2013 to 2014, reaching $920.5 billion. Even though net revenue decreased in 2014, companies continued to invest. Capital and exploratory spending for the companies in 2014 totaled $226.4 billion, up 9.3% from 2013.

The total worldwide liquids production for the 143 firms increased 8.41 percent 3.32 billion bbl, while total worldwide gas production increased 0.54 percent to a total of 17 tcf (*Oil and Gas Journal,* September 7, 2015). Meanwhile, the firms increased both oil and natural gas production and reserves from 2013 to 2014. Domestic production of liquids increased about 16.73 percent from 2013 to 1.97 billion bbl, and domestic natural gas production was up about 3.95 percent to 12.4 tcf in 2014. US liquids reserves from the OGJ150 firms increased by 9.85% up to 25.53 billion bbl, and US natural gas reserves increased by 8.56% to 172.92 tcf. For context, the OGJ150 domestic crude production represents about 62 percent of total domestic production (3.18 billion bbl, according to EIA) in 2014. The OGJ150 natural gas production represents about 48 percent of total domestic production (31.3 tcf, according to EIA) in 2014.

[10] Oil and Gas Journal. "OGJ150 Earnings Down as US Production Climbs." September 2, 2013.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012

						Worldwide Production		US Production		
Rank by Total Assets	**Company**	**Employees**	**Total Assets ($Million)**	**Total Revenue ($Million)**	**Net Income ($Million)**	**Liquids (Million bbl)**	**Natural Gas (Bcf)**	**Liquids (Million bbl)**	**Natural Gas (Bcf)**	**Net Wells Drilled**
1	ExxonMobil Corp.	75,300	349,493	411,939	33615	631	2,645	111	1,346	732
2	Chevron Corp.	64,700	266,026	211,970	19310	508	1,744	166	456	1125
3	ConocoPhillips	19,100	116,539	55,517	6938	270	1,443	172	679	492
4	Anadarko Petroleum Corp.	6,100	61,689	18,470	-1563	154	951	118	951	854.6
5	Occidental Petroleum Corp.	11,700	56,259	21,947	630	163	331	87	173	478.8
6	Apache Corp.	4,950	55,952	13,851	-5060	142.2	580	70.25	215.8	816.5
7	Devon Energy Corp.	6,600	50,637	19,566	1691	129	701	67	660	481
8	Chesapeake Energy Corp.	5,500	40,751	20,951	2056	75.4	1095	75.4	1095	682
9	Hess Corp.	3,045	38,578	11,439	2374	89	197	54	66	211
10	Marathon Oil Corp.	3,330	36,011	11,258	3046	118	295	68	113	666
11	EOG Resources Inc.	3,000	34,763	18,035	2915	134.7	506.3	132	348.4	869
12	Noble Energy Inc.	2,735	22,553	5,101	1214	49	362	32	189	324.4
13	Freeport-McMoRan Inc.	35,000	20,834	4,710	-4479	43	82	43	82	210
14	Murphy Oil Corp.	1,712	16,742	5,476	906	55.4	162.8	25	32.3	189
15	Linn Energy LLC	1,800	16,424	4,983	-452	38.8	209	38.8	209	699
16	Continental Resources Inc.	300	15,145	4,802	977	44.53	114	44.53	114	388.5
17	Pioneer Natural Resources Co.	4,075	14,926	5,055	930	48.48	154.4	48.48	154.4	502
18	Southwestern Energy Corp.	2,781	14,925	4,038	924	0.466	765	0.466	765	221
19	Whiting Petroleum Corp.	1282	14,020	3,085	65	36.77	30.22	36.77	30.22	257.1
20	Denbury Resources Corp.	1,523	12,728	2,435	635	25.77	8.379	25.77	8.379	55.9

Source: Oil and Gas Journal. "OGJ150" September 7, 2015. The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S.

Notes: The source for employment figures is Hoovers, a D&B Company. (Data accessed on January 20, 2016. Employee numbers are for 2014)

The OGJ also releases a period report entitled “Worldwide Gas Processing Survey”, which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughput of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, with large firms owning multiple facilities, which also tend to be relatively large (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264, or 46 percent, of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 165 companies in 2014 (*Oil and Gas Journal.* September 7, 2015, "Gas Pipeline Table," pp. 126-128). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2014. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of Top 20 pipeline companies and the Top 20 firms from the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional markets.

The top 20 companies maintain about 58 percent of the total pipeline mileage and transport about 52 percent of the total volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $13.2 billion, representing 54 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 69 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2014

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Operating Revenue ($000s)	Net Income ($000s)
1	Tennessee Gas Pipeline Co.	11,917	2,990,155	1,192,621	331,768
2	Texas Eastern Transmission LP	9,592	2,610,451	1,165,248	318,519
3	Dominion Transmission Inc.	3,842	1,151,691	1,042,755	308,512
4	Transcontinental Gas Pipe Line Co. LLC	9,183	4,655,090	1,413,206	289,463
5	Florida Gas Transmission Co. LLC	5,324	902,592	795,990	234,412
6	Columbia Gas Transmission LLC	9,641	1,379,418	1,116,715	200,271
7	Northern Natural Gas Co.	14,781	1,025,465	749,039	150,275
8	Southern Natural Gas Co.	7,033	961,725	577,037	146,469
9	ETC Tiger Pipeline LLC	196	340,851	279,299	130,851
10	Kinder Morgan Lousiana Pipeline LLC	136	2,803	265,334	130,678
11	Natural Gas Pipeline Co. of America	9,122	1,417,903	651,548	116,693
12	Rockies Express Pipeline LLC	1,712	789,454	805,485	116,630
13	El Paso Natural Gas Co.	10,222	1,318,671	577,604	113,429
14	Colorado Interstate Gas Co.	4,225	839,291	402,882	108,983
15	Northwest Pipeline LLC	3,890	686,974	470,050	107,172
16	Dominion Cove Point LNG LP	136	92,710	296,555	97,654
17	Texas Gas Transmission LLC	5,766	1,154,029	406,562	97,237
18	Enable Gas Transmission LLC	5,902	913,254	494,067	93,115
19	Lake Charles LNG Co. LLC1 (new)	-	-	216,247	92,236
20	Equitrans LP	900	635,883	268,052	92,036
	TOTAL FOR TOP 20	113,520	23,868,410	13,186,296	3,276,403
	TOTAL FOR ALL COMPANIES	195,194	46,293,010	24,514,239	4,776,194

Source: *Oil and Gas Journal*. September 7, 2015. "Gas Pipeline Table" pp.126-128.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the major U.S. energy producers and reports summary information in the publication "The Performance Profiles of Major Energy Producers".[11] This information is used in annual report to Congress, and is released to the public in aggregate form. While the companies that report information to the FRS each year changes,

[11] The "Performance Profiles of Major Energy Producers 2009" released on February 25, 2011 is the most recent release of this report.

the EIA makes an effort to retain sufficient consistency to reliably evaluate trends. For 2009, 30 companies in the FRS[12] accounted for 43 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 78 percent of U.S. refining capacity, and 0.3 percent of U.S. electricity net generation (U.S. EIA, 2011). Table 2-22 aggregates a series of financial trends selected from the FRS firms' financial statements presented in 2008 dollars. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well, followed by all three financial factors dropping off significantly in 2009. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, though the decrease in net income spans both 2008 and 2009 mainly as a factor of oil and natural gas prices declining significantly during the latter half of 2008.

[12] Alenco, Alon USA, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chalmette, Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., Western Refining, WRB Refining LLC, and XTO Energy, Inc.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9
2009	1,136.8	1,085.9	50.8	10.8	18.7	29.5	29.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).
* Other Income includes other revenue and expenses (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

Table 2-23 shows the estimated return on investments in percentage terms for a variety of business lines in 1998, 2003, 2008, and 2009 for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production was the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent in 1998, 2003, and 2008, with a significant decrease in 2009. Returns to foreign oil and natural gas production rose above domestic production in 2008 and 2009. Electric power generation and sales emerged as a highly profitable line of business in 2008 for the FRS companies quickly followed by a significant decline in 2009.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, 2008, and 2009 (percent)

Line of Business	1998	2003	2008	2009
Petroleum	10.8	13.4	11.9	4.5
U.S. Petroleum	10	13.7	8.1	0.4
Oil and Natural Gas Production	12.5	16.5	10.7	3.5
Refining/Marketing	6.6	9.3	2.4	-6.6
Pipelines	6.7	11.5	2.4	4.7
Foreign Petroleum	11.9	13.0	17.8	10.3
Oil and Natural Gas Production	12.5	14.2	16.3	11
Refining/Marketing	10.6	8.0	26.2	5.8
Downstream Natural Gas*	-	8.8	5.1	9.6
Electric Power	-	5.2	181.4	-32
Other Energy	7.1	2.8	-2.1	5.1
Non-energy	10.9	2.4	-5.3	2.8

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).
Note: Return on investment measured as contribution to net income/net investment in place.
* The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2009 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008)[13] and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008[13], about 13 percent of the total paid to U.S. authorities.

The difference between total current taxes and U.S. federal, state, and local taxes includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24 foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

[13] Data was withheld in 2009 to avoid disclosure.

Table 2-24 Income and Production Taxes, 1990-2009 (Million 2008 Dollars)

Year	US Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507
2009*	-1,655	35,478	-5,988	29,490	-173

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).
*In 2009, data on the U.S. Federal Investment Tax Credit and U.S. State and Local Income Taxes were withheld to avoid disclosure.

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This chapter describes the emissions and engineering cost analysis for the final NSPS. The first section discusses the emissions points and control options. The following section describes each step in the emissions and engineering cost analysis and presents an overview of results. Detailed tables describing the impacts for each source and option can be found at the end of the chapter. We provide reference to the detailed Technical Support Document (TSD) prepared by the EPA for the reader interested in a greater level of detail.[14]

3.2 Sector Emissions Overview

This section provides estimates of overall emissions from the crude oil and natural gas industry to provide context for estimated reductions as a result of the rule. Crude oil and natural gas production sector VOC emissions are approximately 2.8 million tons, according to the 2011 EPA National Emissions Inventory (NEI). The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt CO_2 Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2 Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016).

For the analysis supporting this final action, including this RIA, we used the methane 100-year global warming potential (GWP) of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of Greenhouse Gas Emissions and Sinks (GHG Inventory) and the Greenhouse Gas Reporting Program (GHGRP).[15] The use of

[14] U.S. EPA. 2016. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.

[15] See, for example Table A-1 to subpart A of 40 C.F.R. part 98.

the 100-year GWP of 25 for methane value is currently required by the UNFCCC for reporting of national inventories, such as the GHG Inventory. Updated estimates for methane GWP have been developed by IPCC (2013).[16] The most recent 100-year GWP estimates for methane, which are presented in the IPCC Fifth Assessment Report (AR5, 2013), range from 28-36. In discussing the science and impacts of methane emissions generally, we use the GWP range of 28-36. When presenting emissions estimates, we use the GWP of 25 for consistency and comparability with other emissions estimates in the U.S. and internationally.

3.3 Emissions Points and Pollution Controls assessed in the RIA

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. Additional technical details on the engineering and cost basis of the analysis is presented in the TSD.

Completions of Hydraulically Fractured and Re-fractured Oil Wells: Well completion activities include multiple steps after the well bore hole has reached the target depth. The highest emissions are from venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. The TSD separately considers developmental wells and exploratory wells. Developmental wells are wells drilled within known boundaries of a proven oil or gas field, while exploratory or "wildcat" wells are wells drilled in areas of new or unknown potential.

The EPA considered techniques that have been proven to reduce emissions from well completions: reduced emissions completions (RECs) and completion combustion, as well as re-injecting the natural gas back into the well or another well, using the gas as an on-site fuel source, or use for another beneficial purpose. The use of a REC not only reduces emissions but delivers natural gas product that would typically be vented to the sales meter. Completion combustion destroys the organic compounds. Technical barriers to the operation of a separator

[16] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.

such as well pressure and flowback composition can limit the feasibility of RECs in some situations. Other barriers, such as proximity of pipelines, may prevent recovered gas from being routed to a sales line, but do not necessarily prevent reinjection or on-site use.

Fugitive Emissions: There are several potential sources of fugitive emissions throughout the oil and natural gas sector. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and pressure or mechanical stresses can also cause components or equipment to leak. Potential sources of fugitive emissions include valves, connectors, pressure relief devices, open-ended lines, flanges, closed vent systems, and thief hatches or other openings on a controlled storage unit. These fugitive emissions do not include devices that vent as part of normal operations.

The TSD considers fugitive emissions from production wellsites and compressor stations. The EPA considered two options for reducing methane and VOC emissions from leaking components: a leak monitoring program based on individual component monitoring using EPA Method 21 for leak detection combined with a leak correction, and a leak monitoring program based on the use of OGI leak detection combined with leak correction. In addition, alternative frequencies for fugitive emissions surveys were considered: annual, semiannual, and quarterly.

Pneumatic Controllers: Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control a valve. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non-gas-driven controllers are typically used. Continuous bleed pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. The EPA evaluated the impact of replacing high-bleed controllers with low-bleed controllers.

Pneumatic Pumps: Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or a set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996) and can be a significant source of methane and VOC emissions. Pneumatic chemical and methanol injection pumps are generally used to pump small volumes of chemicals or methanol into well bores, surface equipment, and pipelines. Typically, these pumps include plunger pumps with a diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure. They are typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are used widely in the onshore oil and gas sector to move larger volumes of liquids per unit of time at lower discharge pressures than chemical and methanol injection pumps. The usage of these pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and circulation of heat trace medium at wellsites in cold climates during winter months.

For both of these types of pumps, emissions occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratio's between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump. As discussed in the white papers, several options for reducing methane and VOC emissions were identified: replace a natural gas-assisted pump with an instrument air pump, replace a natural gas-assisted pump with a solar-charged direct current pump (solar pumps), replace a natural gas-assisted pump with an electric pump, and route pneumatic pump emissions to a control device. The EPA evaluated the impact of routing pump emissions to a pre-existing on-site control device.

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

Emissions from compressors occur when natural gas leaks around moving parts in the compressor. In a reciprocating compressor, emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. Over time, during operation of the compressor, the rod packing system becomes worn and will need to be replaced to prevent excessive leaking from the compression cylinder. The control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

Emissions from centrifugal compressors depend on the type of seal used: either "wet", which use oil circulated at high pressure, or "dry", which use a thin gap of high pressure gas. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency. Limiting or reducing the emission from the rotating shaft of a centrifugal compressor using a mechanical dry seal system was evaluated. For centrifugal compressors equipped with wet seals, a flare was evaluated as an option for reducing emissions from centrifugal compressors.

3.4 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make to comply with the NSPS. A detailed discussion of the methodology used to estimate cost impacts is presented in the TSD.

The following sections describe each step in the engineering cost analysis. First, representative facilities are established for each source category, including baseline emissions and control options. Second, the number of incrementally affected facilities for each type of equipment or facility are projected. National emissions reductions and cost estimates are calculated by multiplying representative factors, from the first step, by the estimated number of affected facilities in each projection year, from the second step. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted for useful processes or sold. The national cost estimates include estimated revenue from product recovery where applicable.

3.4.1 Regulatory Options

For each emissions source, point, and control option, the TSD develops a representative facility. The characteristics of this facility include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. In this RIA, we examine three broad regulatory options. Table 3-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for promulgation.

Table 3-1 Emissions Sources and Controls Evaluated for the NSPS

Emissions Point	Emissions Control	Option 1	Option 2 (final)	Option 3
Well Completions and Recompletions				
Hydraulically Fractured Development Oil Wells	REC / Combustion	**X**	**X**	**X**
Hydraulically Fractured Wildcat and Delineation Oil Wells	Combustion	**X**	**X**	**X**
Fugitive Emissions				
Well Sites	Planning, Monitoring and Maintenance	**Annual**	**Semiannual**	**Quarterly**
Gathering and Boosting Stations	Planning, Monitoring and Maintenance	**Semiannual**	**Quarterly**	**Quarterly**
Transmission Compressor Stations	Planning, Monitoring and Maintenance	**Semiannual**	**Quarterly**	**Quarterly**
Pneumatic Pumps				
Well Sites	Route to control	**X**	**X**	**X**
Pneumatic Controllers				
Natural Gas Transmission and Storage	Emissions limit	**X**	**X**	**X**
Reciprocating Compressors				
Natural Gas Transmission and Storage	Maintenance	**X**	**X**	**X**
Centrifugal Compressors				
Natural Gas Transmission and Storage	Route to control	**X**	**X**	**X**

The selected Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers throughout the oil and natural gas source category.

The unselected Options 1 and 3 differ from the selected Option 2 with respect to the requirements for fugitive emissions. Option 1 requires fugitive emissions survey and repair programs be performed annually at the affected newly drilled or refractured oil and natural gas well sites, and semiannually at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Fewer surveys being performed leads to lower costs and emissions reductions than under the selected Option 2. Finally, the more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in higher costs and higher emissions reductions than Option 2.

3.4.2 Projection of Incrementally Affected Facilities

The second step in estimating national costs and emissions impacts of the final rule is projecting the number of incrementally affected facilities. Incrementally affected facilities are facilities that would be expected to change their emissions control activities as a result of the NSPS. Facilities in states with similar state-level requirements and facilities with only recordkeeping requirements are not included within incrementally affected facilities.

The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. Over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. In 2025, affected facilities include facilities newly established or modified in 2025, and also facilities which were newly established or modified from 2016 through 2024 and are still operating in 2025. The analysis has assumed that all new equipment and facilities established from 2016 through 2024 are still in operation in 2025. This approach differs from the way affected facilities were estimated in the proposal RIA. At proposal, 2020 was assumed to represent a single year of potential impacts, and 2025 included newly established or modified facilities from 2020 through 2024. This methodological change results in a higher estimate of the number of affected facilities than at proposal and better represents the impacts of the rule.

The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels taken from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year changes over the past ten years in the GHG Inventory. New and modified hydraulically fractured oil well completions and wellsites are based on projections and growth rates consistent with the drilling activity in the Annual Energy Outlook. For the final RIA, the projections have been updated to reflect the projections in the 2015 Annual Energy Outlook. In addition, while the projections used in the proposal RIA were based on the long-term growth trajectory from 2012 to 2025, the current analysis is based on the full times series in the 2015 AEO reference scenario.

The 2015 Annual Energy Outlook was the most recent projection available at the time the analysis underlying this RIA was being prepared. The 2015 AEO includes the growth in U.S. crude oil production over the last two years, along with the late-2014 drop in global crude oil prices, and reflects how these factors have altered the economics of the oil market. In comparison to the 2014 AEO reference case, the 2015 AEO reference case shows higher crude oil production (18 percent higher for 2025 in the 2015 AEO), slightly lower natural gas production (about 4 percent lower for 2025 in the 2015 AEO), lower Brent spot and West Texas Intermediate crude oil prices, and lower total wells drilled in the lower 48 states (about 20 percent lower for 2025 in the 2015 AEO).

While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to largely because of the limited information available on the turnover rate of emissions sources and controls. For this RIA, we have used the U.S. EIA's National Energy Modelling System (NEMS) to generate a limited set of future year projections to inform impact estimates for subset of affected sources. We also used the model to estimate key market impacts of the rules, based upon EPA's parameterization of regulatory costs and natural gas capture in the model. While NEMS produces highly regarded projections of production and well drilling, and is useful to estimate market impacts of the NSPS, it is not a compliance model and does not directly model affected units. In addition, in a dynamic industry like oil and natural gas, technological progress in control technology is also likely to be dynamic. These factors make it reasonable to use 2025 as the latest year of analysis as extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.

We also reviewed state regulations and permitting requirements which require mitigation measures for many emission sources in the oil and natural gas sector. State regulations in Colorado and Wyoming both require RECs for hydraulically fractured oil and gas wells, and North Dakota requires combustion of completion emissions. Sources in Colorado, Wyoming, Utah, and Ohio are subject to fugitive emissions requirements. Applicable facilities in these states are not included in the estimates of incrementally affected facilities presented in the RIA, as sources in those states are already subject to similar requirements to the federal standards. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements (e.g., to comply with the on-site separator requirement) are not reflected in this RIA. A more detailed discussion on the derivation of the baseline for this rule is presented for each emissions source in the TSD. In section 4.3.1 of the TSD, Table 4-3 provides a detailed breakout of affected oil well completions.

Table 3-2 Incrementally Affected Sources under Final NSPS, 2016 to 2025 on an Annual Basis

	Incrementally Affected Sources[1]									
Emissions Sources	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Oil Well Completions and Recompletions	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	14,000	14,000
Fugitive Emissions	19,000	19,000	19,000	19,000	19,000	19,000	19,000	20,000	20,000	21,000
Pneumatic Pumps	790	790	790	790	790	790	790	790	790	790
Compressors	33	33	33	33	33	33	33	33	33	33
Pneumatic Controllers	96	96	96	96	96	96	96	96	96	96
Total	32,000	32,000	33,000	33,000	33,000	33,000	33,000	34,000	35,000	35,000

[1] Incrementally affected sources includes sources that have to change their control activity as a result of the rule. The table does not include estimate counts of a) affected facilities in states with similar state-level requirements to the NSPS, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except in the case of oil well completions and fugitive emissions at wellsites.

Table 3-2 presents the number of affected sources for each year of analysis after generally accounting for state regulations. In addition to the caveats regarding facilities affected by state regulations described above, facilities with only recordkeeping requirements are also not included within incrementally affected facilities (e.g., wells with low GOR are not included in the estimate of facilities affected by the oil well completion requirements).

Table 3-3 Total Number of Affected Sources for the NSPS in 2020 and 2025

Emissions Sources	Affected Sources[1] 2020	Affected Sources[1] 2025
Hydraulically Fractured and Re-fractured Oil Well Completions	13,000[3]	14,000[3]
Fugitive Emissions	94,000	190,000
Pneumatic Pumps	3,900	7,900
Compressors	170	330
Pneumatic Controllers	480	960
Total[2]	110,000	220,000

[1] In addition to newly affected sources in 2020, total affected sources in 2020 include sources that become affected in the 2016-2019 period and are assumed to be in continued operation in 2020. Similarly, affected sources in 2025 reflect sources newly constructed or modified from 2016 to 2025, assumed to still be in operation in 2025. The table does not include estimate counts of: a) affected facilities in states already regulating those sources, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except for oil well completions and fugitive emissions at wellsites. Estimates are rounded to two significant digits.
[2] Totals may not sum due to independent rounding.
[3] Affected oil well completions include a mix of RECs and flaring based on subcategory and technical infeasibility criteria. Exploratory and delineation wells are required to combust emissions. Of development oil well completions, 50% are estimated to be feasible to perform a REC; the remainder would combust emissions (either because they are unable to implement a REC due to low pressure or other technical infeasibility reasons). See section 4.3.1 of the TSD for a detailed breakout of affected oil well completions

Table 3-3 presents estimates of the total number of affected sources for this final rule. Note that hydraulically fractured and re-fractured oil well completions do not grow significantly from 2020 to 2025, while other sources do. This is a result of completions being a one-time activity in a given year, while other sources are affected and remain affected as they continue to operate, thus these sources accumulate over time. The estimates for hydraulically fractured and re-fractured oil well completions and fugitive emissions at wellsites (a large fraction of the incrementally affected sources under the fugitive emissions provisions) include both new and modified sources.

The estimates for other sources are based upon projections of new sources alone, and do not include replacement or modification of existing sources. While some of these sources are unlikely to be modified, particularly pneumatic pumps and controllers, the impact estimates may be under-estimated due to the focus on new sources. In the proposal, the EPA solicited comments on these projection methods as well as solicits information that would improve our estimate of the turnover rates or rates of modification of relevant sources, as well as the number of wells on wellsites. While the EPA received comments on the projection methods used in the proposal RIA, we did not receive comments with sufficient information to further incorporate modification and turnover in the projection methodologies. The EPA has modified its methodology for using historical inventory information to estimate new sources reflecting comments received, resulting in lower estimates of the number of new compressor stations, pumps, compressors, and pneumatic controllers constructed each year. Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and pneumatic controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years. In years when the total count of equipment decreased, there were assumed to be no newly constructed units.

3.4.3 Emissions Reductions

Table 3-4 summarizes the national emissions reductions for the evaluated NSPS emissions sources and points for 2020 and 2025. These reductions are estimated by multiplying the unit-level emissions reductions associated with each applicable control and facility type by the number of incrementally affected sources. The detailed description of emissions controls is provided in the TSD. Please note that all results have been rounded to two significant digits.

Table 3-4 Emissions Reductions for Final NSPS Option 2, 2020 and 2025

Source/Emissions Point	Emissions Reductions, 2020			
	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)
Oil Well Completions and Recompletions	120,000	97,000	12	2,600,000
Fugitive Emissions	170,000	46,000	1,700	3,800,000
Pneumatic Pumps	13,000	3,600	140	290,000
Compressors	4,000	110	3	92,000
Pneumatic Controllers	1,300	37	1	30,000
Total	**300,000**	**150,000**	**1,900**	**6,900,000**
	Emissions Reductions, 2025			
Source/Emissions Point	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
Oil Well Completions and Recompletions	120,000	100,000	12	2,800,000
Fugitive Emissions	350,000	94,000	3,600	7,900,000
Pneumatic Pumps	26,000	7,200	270	590,000
Compressors	8,100	220	7	180,000
Pneumatic Controllers	2,700	74	2	61,000
Total	**510,000**	**210,000**	**3,900**	**11,000,000**

3.4.4 Product Recovery

The annualized cost estimates presented below include revenue from additional natural gas recovery. Several emission controls for the NSPS capture methane and VOC emissions that would otherwise be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For the environmental controls that avert the emission of saleable natural gas, we base the estimated revenues from averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year.

The controls that result in natural gas recovery are: RECs at hydraulically fractured oil wells, fugitive emissions monitoring and repair, rod packing replacement in reciprocating compressors, and the use of low-bleed pneumatic devices. The requirements for completions at exploration and delineation wells, pneumatic pumps, and centrifugal compressors do not result in natural gas recovery. In some of these cases, alternative control strategies do result in natural gas recovery, but these alternative controls were not assumed as part of this analysis. For example, alternatives to routing pneumatic pump emissions to a control device include substituting a solar or electric pump where a gas-driven pump would have otherwise been used.

Table 3-5 summarizes natural gas recovery and revenue included in annualized cost calculations. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The EIA's 2015 Annual Energy Outlook reference case projects Henry Hub natural gas prices to be $4.88/MMBtu in 2020 and $5.46/MMBtu in 2025 in 2013 dollars.[17] After adjusting to $/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $4.94/Mcf in 2020 and $5.52 in 2025. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.[18]

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

[17] Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
[18] An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price. See http://www.eia.gov/oiaf/analysispaper/henryhub/.

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

Table 3-5 Estimated Natural Gas Recovery (Mcf) for selected Option 2 in 2020 and 2025

	2020		2025	
Source/Emissions Point	**Gas recovery (Mcf)**	**Value of recovery**	**Gas recovery (Mcf)**	**Value of recovery**
Oil Well Completions and Recompletions	5,700,000	$23,000,000	6,100,000	$24,000,000
Fugitive Emissions	9,800,000	$39,000,000	20,000,000	$80,000,000
Pneumatic Pumps	0	$0	0	$0
Compressors	180,000	$720,000	360,000	$1,400,000
Pneumatic Controllers	69,000	$280,000	140,000	$550,000
Total	16,000,000	$63,000,000	27,000,000	$110,000,000

As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. In addition, there is geographic variability in wellhead prices, which can also influence estimated engineering costs. For Option 2, a $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about 5 percent. Section 3.5.2 further examines the sensitivity of national compliance costs to natural gas prices.

3.4.5 Engineering Compliance Costs

Table 3-6 summarizes the capital and annualized costs and revenue from product recovery for the evaluated emissions sources and points. The capital costs represent total capital cost expenditures associated with affected units in 2020 and 2025, including capital cost expenditures made prior to the analysis year. The detailed description of cost estimates is provided in TSD. To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. This approach is mathematically equivalent to establishing an overall, representative project time horizon and annualizing costs after consideration of control options that would need to be replaced periodically within the given time horizon.

Table 3-6 Engineering Compliance Cost Estimates for Final NSPS Option 2 in 2020 and 2025 (millions 2012$)

	Compliance Costs, 2020			
Source/Emissions Point	**Capital Costs[1]**	**Annualized Costs (without savings)**	**Revenue from Product Recovery**	**Nationwide Annualized Costs with Addl. Revenue (2012$)**
Oil Well Completions and Recompletions	$150	$150	$23	$130
Fugitive Emissions	$77	$230	$39	$190
Pneumatic Pumps	$21	$3	$0	$3.1
Compressors	$1.4	$0.9	$0.7	$0.2
Pneumatic Controllers	$0.1	$0.0	$0.3	-$0.27
Reporting and Recordkeeping	$0	$6.3	$0	$6.3
Total	**$250**	**$390**	**$63**	**$320**

	Compliance Costs, 2025			
Source/Emissions Point	**Capital Costs[1]**	**Annualized Costs (without savings)**	**Revenue from Product Recovery**	**Nationwide Annualized Costs with Addl. Revenue (2012$)**
Oil Well Completions and Recompletions	$160	$160	$24	$130
Fugitive Emissions	$160	$460	$80	$380
Pneumatic Pumps	$43	$6	$0	$6
Compressors	$2.9	$1.8	$1.4	$0.3
Pneumatic Controllers	$0.2	$0.0	$0.6	-$0.5
Reporting and Recordkeeping	$0.0	$6.3	$0	$6.3
Total	**$360**	**$640**	**$110**	**$530**

[1] Capital costs represent total capital costs associated with control of affected sources in 2020 and 2025, including expenditures made in previous years. Sums may not total due to independent rounding.

Engineering capital costs were annualized using a 7 percent interest rate. Section 3.4

provides a comparison to using a 3 percent interest rate. Different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used to annualize capital costs of emissions controls:

- Reduced emissions completions and combustion devices: 1 year
- Fugitive emissions monitoring program design: 8 years
- Reciprocating compressors rod packing: 3.8 – 4.4 years
- Centrifugal compressors and pneumatic pumps: 10 years
- Pneumatic controllers: 15 years

Note the large majority of capital costs are required for the completions fugitive emissions requirements. Alternative assumptions of the lifetimes of these expenditures are most likely influence estimates of total compliance costs, where alternative assumptions for compressors, pumps, and controllers would likely to have relatively small effects.

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this final rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Preamble for more detail). The 2020 and 2025 reporting and recordkeeping costs in this RIA are assumed to be equal to the third year cost reporting in the ICR cost estimates ($6.3 million). These recordkeeping and recordkeeping costs are estimated for the selected Option 2 for all new and modified facilities regardless of whether they implement additional controls as a result of the NSPS. While these costs may differ across regulatory options as a result of the varying frequency of the fugitives program across the options, we do not have the information to estimate the ICR burden for the unselected Option 1 and 3. As a result, we assume all options have the same recordkeeping and reporting cost burden. Note also that reporting and recordkeeping costs are included for all affected entities, regardless of whether they are in states with regulatory requirements similar to the final NSPS.

3.4.6 Comparison of Regulatory Alternatives

Table 3-7 presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025. The requirements between the options vary with respect to the fugitive emissions requirements. The less stringent Option 1 requires annual monitoring for well sites under the fugitive emissions program and semi-annual for compressor stations. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. Annual, semi-annual, and quarterly fugitive emissions surveys are assumed to result in reductions in emissions of 40 percent, 60 percent and 80 percent, respectively.[19] For more information on these assumptions, please see Section 4.3.2.2 of the TSD. Natural gas recovery also varies as a result of survey frequency. Variation in natural gas recovery, capital and annualized costs reflect these differences in the number of affected facilities and frequency of fugitive emissions surveys. In addition, the ratio between national compliance costs and national emissions reductions is presented using both the single pollutant and multipollutant approach.

Table 3-7 Comparison of Regulatory Alternatives

	Regulatory Alternative		
	Option 1	**Option 2 (final)**	**Option 3**
Impacts in 2020			
Affected Sources	110,000	110,000	110,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	250,000	300,000	350,000
VOC Emissions Reduction (short tons/year)	130,000	150,000	160,000
Natural Gas Recovery (Mcf)	13,000,000	16,000,000	19,000,000
Compliance Costs			
Capital Costs (2012$)	$240,000,000	$250,000,000	$260,000,000
Annualized Costs Without Addl. Revenue (2012$)	$290,000,000	$390,000,000	$570,000,000
Annualized Costs With Addl. Revenue (2012$)	$240,000,000	$320,000,000	$490,000,000
Impacts in 2025			
Affected Sources	220,000	220,000	220,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	390,000	510,000	610,000
VOC Emissions Reduction (short tons/year)	170,000	210,000	230,000

[19] The EPA performed a sensitivity analysis based on the midpoints of the Method 21 emission reduction efficiency percentages, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. Even based on this conservative analysis, the EPA finds that the chosen monitoring frequencies are the BSER for these sources. The EPA additionally concluded that the 40, 60, and 80 percent emission reduction efficiency percentages are reasonable and accurate. See section 4.3.2.2 of the final TSD for further information.

Natural Gas Recovery (Mcf)	20,000,000	27,000,000	33,000,000
Compliance Costs			
Capital Costs (2012$)	$350,000,000	$360,000,000	$380,000,000
Annualized Costs Without Addl. Revenue (2012$)	$440,000,000	$640,000,000	$1,000,000,000
Annualized Costs With Addl. Revenue (2012$)	$360,000,000	$530,000,000	$880,000,000

3.5 Engineering Cost Sensitivity Analysis

This section illustrates the sensitivity of engineering cost and emissions analysis results of Option 2 to choice of discount rate and natural gas prices.

3.5.1 Compliance Costs Estimated Using 3 and 7 Percent Discount Rates

Table 3-8 shows that the choice of discount rate has minor effects on the nationwide annualized costs of the final rule.

Table 3-8 Annualized Costs using 3 and 7 Percent Discount Rates for Final NSPS Option 2 in 2020 and 2025 (millions 2012$)

	Nationwide Annualized Costs, 2020		Nationwide Annualized Costs, 2025	
	7 percent	**3 percent**	**7 percent**	**3 percent**
Oil Well Completions and Recompletions	$130	$130	$130	$130
Fugitive Emissions	$190	$190	$380	$380
Pneumatic Pumps	$3.1	$2.5	$6.1	$5
Compressors	$0.16	$0.12	$0.31	$0.24
Pneumatic Controllers	-$0.27	-$0.27	-$0.53	-$0.54
Reporting and Recordkeeping	$6.3	$6.3	$6.3	$6.3
Total	**$320**	**$320**	**$530**	**$520**

The choice of discount rate has a small effect on nationwide annualized costs. Discount rate generally affects estimates of annualized costs for controls with high capital costs relative to annual costs. The compliance costs related to oil well completions and fugitive emissions surveys occur in each year, so the interest rate has little impact on annualized costs for these sources. The annualized costs for pneumatic pumps, compressors, and pneumatic controllers are sensitive to interest rate, but these constitute a relatively small part of the total compliance cost estimates for the rule.

3.5.2 Sensitivity of Compliance Costs to Natural Gas Prices

The annualized compliance cost estimates presented in this RIA include revenue from additional natural gas recovery, and therefore national compliance costs depend the price of natural gas. This section examines the sensitivity of national compliance costs to varying natural gas prices. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. As discussed earlier, the $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.

EPA recognizes that current natural gas prices are below $4/Mcf. In 2015, the Henry Hub Natural Gas Spot Price ranged between about $2 and $3 dollars per MMBtu (about $1.94/Mcf and $2.91/Mcf, respectively). [20] The models used to forecast natural gas prices in the Annual Energy Outlook are deterministic. A deterministic model does not incorporate potential stochastic influences and and will therefore producs the same result for each model run using all else equal. While the Annual Energy Outlook is a commonly referenced publication that provides mid-term forecasts, the U.S. EIA also produces the Short-Term Energy Outlook (STEO), which provides confidence intervals for some energy prices over a shorter time frame based on the prices paid for financial derivatives (e.g., options) based on natural gas. To better understand the uncertainty associated with the 2020 and 2025 natural gas price assumed in this analysis, EPA reviewed the March 2016 STEO, which includes monthly forecasted natural gas prices through 2017.[21] While the STEO analysis only extends to the end of 2017, the published

[20] Assuming the average heat context of natual gas is 1,028 Btu per cubic foot, 1 Mcf = 1.028 MMBtu. Based on this assumption, to convert natural gas prices denominated in MMbtu to Mcf, the $/MMbtu is multiplied by 1/1.028 or 0.973.

[21] U.S. Energy Information Administration (U.S. EIA). 2016. Short-Term Energy Outlook, March 8, 2016. <http://www.eia.gov/forecasts/steo/report/natgas.cfm> March 8, 2016.

confidence intervals for future natural gas prices can provide some basis for understanding the potential uncertainty around slightly longer-term forecasts.

In the STEO, forecasted prices are traded futures contracts. Based on this information the STEO also presents a 95% confidence interval for the price of natural gas through 2017. However, that the probability analysis uses the Henry Hub spot price, rather than the wellhead price paid to producer. The EIA analysis projects an expected December 2017 Henry Hub price of $3.31 per MMBtu ($3.22/Mcf) with a 95 percent confidence interval of $1.45 to $5.25 per MMBtu ($1.41/Mcf to $5.10/Mcf). While this confidence interval is not for wellhead natural gas prices, it is relevant for understating the challenges associated with precisely predicting future natural gas prices.

To analyze the sensitivity of the engineering costs of the rule to assumed natural gas prices, Table 3-12 presents nationwide annualized costs for each source category assuming natural gas prices of $2, $3, $4, and $5 per Mcf.

Table 3-9 Annualized Costs Using Natural Gas Prices from $2 to $5 per Mcf

	Nationwide Annualized Costs (million 2012$), 2020				**Nationwide Annualized Costs (million 2012$), 2025**			
Source/Emissions Point	**$2/Mcf**	**$3/Mcf**	**$4/Mcf**	**$5/Mcf**	**$2/Mcf**	**$3/Mcf**	**$4/Mcf**	**$5/Mcf**
Oil Well Completions and Recompletions	$140	$130	$130	$120	$150	$140	$130	$130
Fugitive Emissions	$210	$200	$190	$180	$420	$400	$380	$360
Pneumatic Pumps	$3.1	$3.1	$3.1	$3.1	$6.1	$6.1	$6.1	$6.1
Compressors	$0.52	$0.34	$0.16	-$0.023	$1	$0.68	$0.31	-$0.046
Pneumatic Controllers	-$0.13	-$0.20	-$0.27	-$0.33	-$0.25	-$0.39	-$0.53	-$0.67
Reporting and Recordkeeping	$6.3	$6.3	$6.3	$6.3	$6.3	$6.3	$6.3	$6.3
Total	**$350**	**$340**	**$320**	**$310**	**$580**	**$560**	**$530**	**$500**

Note that all figures are rounded to two significant digits. Annualized costs are estimated using a 7 percent discount rate. Totals may not sum due to independent rounding.

For Option 2, a $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $16 million in 2020 and $27 million in 2025, in 2012 dollars. In percentage terms, a $1/Mcf reduction in the wellhead price causes about a 5 percent increase in national compliance costs in either 2020 or 2025. These amounts include revenue from product recovery in all segments. As decribed above, this approach differs with respect to the gathering and boosting and transmission segments between the unit-level cost and emissions reduction analysis supporting BSER decisions (which is focused on control costs borne by regulated sources) and this RIA (which is focused on societal costs). Operators in the gathering and boosting and transmission and storage segments may not own the natural gas they transport, and so may not be able to offset compliance costs with revenue from product recovery in the short term. Changes in costs are affected for the oil well completions, fugitive emissions sources, reciprocating compressors, and pneumatic controllers because control of these sources results in product recovery. Costs for pumps and centrifugal compressors are not affected because routing emissions to a control does not result in product recovery. Valued at $4/Mcf, estimated national gas recovery as a result of the NSPS in the gathering and boosting segment would be about $3 million in 2020 and $6 million in 2025 and in the transmission and storage segment would be about $2 million in 2020 and $4 million in 2025.

3.6 Detailed Impacts Tables

The following tables show the full details of the costs and emissions reductions by emissions sources for each regulatory option in 2020 and 2025.

Table 3-10 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions: Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	National Costs: Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	12,000	110,000	89,000	11	2,400,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	990	9,100	7,600	1	210,000	$3,700,000	$3,700,000
Fugitive Emissions							
Well Pads	94,000	100,000	28,000	1,100	2,300,000	$71,000,000	$100,000,000
Gathering and Boosting Stations	480	10,000	2,800	110	230,000	$1,100,000	$4,200,000
Tranmission Compressor Stations	45	2,600	73	2	59,000	$740,000	$360,000
Pneumatic Pumps							
Well Pads	3,900	13,000	3,600	140	290,000	$21,000,000	$3,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	160	3,500	96	3	79,000	$1,100,000	-$410,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	5	560	15	0	13,000	$360,000	$570,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	480	1,300	37	1	30,000	$110,000	-$270,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$6,300,000
TOTAL	**110,000**	**250,000**	**130,000**	**1,300**	**5,600,000**	**$240,000,000**	**$240,000,000**

Table 3-11 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions				National Costs	
		Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	13,000	110,000	95,000	11	2,600,000	$150,000,000	$130,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	1,100	10,000	8,400	1	230,000	$4,000,000	$4,000,000
Fugitive Emissions							
Well Pads	190,000	210,000	58,000	2,200	4,700,000	$150,000,000	$200,000,000
Gathering and Boosting Stations	960	20,000	5,600	210	460,000	$2,300,000	$8,300,000
Tranmission Compressor Stations	90	5,200	150	4	120,000	$1,500,000	$710,000
Pneumatic Pumps							
Well Pads	7,900	26,000	7,200	270	590,000	$43,000,000	$6,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	320	7,000	190	6	160,000	$2,200,000	-$830,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	10	1,100	31	1	25,000	$720,000	$1,100,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	960	2,700	74	2	61,000	$220,000	-$530,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$6,300,000
TOTAL	**220,000**	**390,000**	**170,000**	**2,700**	**8,900,000**	**$350,000,000**	**$360,000,000**

Table 3-12 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2020

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions: Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	National Costs: Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	12,000	110,000	89,000	11	2,400,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	990	9,100	7,600	1	210,000	$3,700,000	$3,700,000
Fugitive Emissions							
Well Pads	94,000	150,000	42,000	1,600	3,500,000	$75,000,000	$180,000,000
Gathering and Boosting Stations	480	13,000	3,800	140	310,000	$1,100,000	$8,900,000
Tranmission Compressor Stations	45	3,500	97	3	79,000	$740,000	$880,000
Pneumatic Pumps							
Well Pads	3,900	13,000	3,600	140	290,000	$21,000,000	$3,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	160	3,500	96	3	79,000	$1,100,000	-$410,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	5	560	15	0	13,000	$360,000	$570,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	480	1,300	37	1	30,000	$110,000	-$270,000
Reporting and Recordkeeping	0	0	0	0	0	$0	$6,300,000
TOTAL	**110,000**	**300,000**	**150,000**	**1,900**	**6,900,000**	**$250,000,000**	**$320,000,000**

Table 3-13 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2025

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions: Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	National Costs: Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	13,000	110,000	95,000	11	2,600,000	$150,000,000	$130,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	1,100	10,000	8,400	1	230,000	$4,000,000	$4,000,000
Fugitive Emissions							
Well Pads	190,000	310,000	87,000	3,300	7,100,000	$150,000,000	$360,000,000
Gathering and Boosting Stations	960	27,000	7,500	280	610,000	$2,300,000	$18,000,000
Tranmission Compressor Stations	90	7,000	190	6	160,000	$1,500,000	$1,800,000
Pneumatic Pumps							
Well Pads	7,900	26,000	7,200	270	590,000	$43,000,000	$6,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	320	7,000	190	6	160,000	$2,200,000	-$830,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	10	1,100	31	1	25,000	$720,000	$1,100,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	960	2,700	74	2	61,000	$220,000	-$530,000
Reporting and Recordkeeping	0	0	0	0	0	$0	$6,300,000
TOTAL	**220,000**	**510,000**	**210,000**	**3,900**	**11,000,000**	**$360,000,000**	**$530,000,000**

Table 3-14 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions: Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	National Costs: Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	12,000	110,000	89,000	11	2,400,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	990	9,100	7,600	1	210,000	$3,700,000	$3,700,000
Fugitive Emissions							
Well Pads	94,000	200,000	57,000	2,100	4,600,000	$83,000,000	$350,000,000
Gathering and Boosting Stations	480	13,000	3,800	140	310,000	$1,100,000	$8,900,000
Tranmission Compressor Stations	45	3,500	97	3	79,000	$740,000	$880,000
Pneumatic Pumps							
Well Pads	3,900	13,000	3,600	140	290,000	$21,000,000	$3,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	160	3,500	96	3	79,000	$1,100,000	-$410,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	5	560	15	0	13,000	$360,000	$570,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	480	1,300	37	1	30,000	$110,000	-$270,000
Reporting and Recordkeeping	0	0	0	0	0	$0	$6,300,000
TOTAL	**110,000**	**350,000**	**160,000**	**2,400**	**8,000,000**	**$260,000,000**	**$490,000,000**

Table 3-15 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action	Nationwide Emissions Reductions: Methane (short tons/year)	VOC (short tons/year)	HAP (short tons/year)	Methane (metric tons CO2e)	National Costs: Capital Costs	Annualized Costs With Addl. Revenues
Well Completions and Recompletions							
Hydraulically Fractured Development Oil Wells	13,000	110,000	95,000	11	2,600,000	$150,000,000	$130,000,000
Hydraulically Fractured Wildcat and Dilineation Oil Wells	1,100	10,000	8,400	1	230,000	$4,000,000	$4,000,000
Fugitive Emissions							
Well Pads	190,000	420,000	120,000	4,400	9,400,000	$170,000,000	$710,000,000
Gathering and Boosting Stations	960	27,000	7,500	280	610,000	$2,300,000	$18,000,000
Tranmission Compressor Stations	90	7,000	190	6	160,000	$1,500,000	$1,800,000
Pneumatic Pumps							
Well Pads	7,900	26,000	7,200	270	590,000	$43,000,000	$6,100,000
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	320	7,000	190	6	160,000	$2,200,000	-$830,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	10	1,100	31	1	25,000	$720,000	$1,100,000
Centrifigal Compressors							
Natural Gas Transmission and Storage Stations	960	2,700	74	2	61,000	$220,000	-$530,000
Reporting and Recordkeeping	0	0	0	0	0	$0	$6,300,000
TOTAL	**220,000**	**610,000**	**230,000**	**5,000**	**14,000,000**	**$380,000,000**	**$880,000,000**

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The final NSPS is designed to prevent new emissions from the oil and gas sector. For the NSPS, we predict that there will be climate and ozone benefits from methane reductions, ozone and $PM_{2.5}$ health benefits from VOC reductions, and HAP "co-benefits". These co-benefits would occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions. The NSPS is anticipated to prevent 300,000 tons of methane, 150,000 tons of VOC, and 1,900 tons of HAP from new sources in 2020. In 2025, the NSPS is estimated to prevent 510,000 tons of methane, 210,000 tons of VOC, and 3,900 tons of HAP. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are estimated to be 6.9 million metric tons in 2020 and 11 million metric tons in 2025. As described in the subsequent sections, these pollutants are associated with substantial climate, health, and welfare effects. The only benefits monetized in this RIA are methane-related climate benefits. The methane-related climate effects are estimated to be $360 million and $690 million using a 3 percent discount rate in 2020 and 2025, respectively.[22] The specific control techniques for the NSPS are anticipated to have minor emissions disbenefits (e.g., increases in emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), PM, carbon monoxide (CO), and total hydrocarbons (THC)) and emission changes associated with the energy markets impacts.

While we expect that the avoided VOC emissions will also result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, fine particulate matter ($PM_{2.5}$), and HAP, we have determined that quantification of the VOC-related health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that these benefits do not exist; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With the data available, we are not able to provide credible health benefits estimates for this rule, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and

[22] Table 4-3 presents the methane-related climate effects based on $SC\text{-}CH_4$ at discount rates of 2.5, 3, and 5 percent.

VOC reductions.[23] In this chapter, we provide a qualitative assessment of the health benefits associated with reducing exposure to these pollutants, as well as visibility impairment and ecosystem benefits. Table 4-1 summarizes the quantified and unquantified benefits in this analysis.

Table 4-1 Climate and Human Health Effects of Emission Reductions from this Rule

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from methane and carbon dioxide (CO_2)	—[1]	✓	Marten *et al.* (2014), SC-CO_2 TSDs
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA[2]
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	—	—	PM ISA[3]
	Infant mortality (age <1)	—	—	PM ISA[3]
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	—	—	PM ISA[3]
	Hospital admissions—respiratory (all ages)	—	—	PM ISA[3]
	Hospital admissions—cardiovascular (age >20)	—	—	PM ISA[3]
	Emergency room visits for asthma (all ages)	—	—	PM ISA[3]
	Acute bronchitis (age 8-12)	—	—	PM ISA[3]
	Lower respiratory symptoms (age 7-14)	—	—	PM ISA[3]
	Upper respiratory symptoms (asthmatics age 9-11)	—	—	PM ISA[3]
	Asthma exacerbation (asthmatics age 6-18)	—	—	PM ISA[3]
	Lost work days (age 18-65)	—	—	PM ISA[3]
	Minor restricted-activity days (age 18-65)	—	—	PM ISA[3]
	Chronic Bronchitis (age >26)	—	—	PM ISA[3]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[3]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[3]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]

[23] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[2,4]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,4]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	—	—	Ozone ISA[3]
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[3]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	—	—	Ozone ISA[3]
	Hospital admissions—respiratory causes (age <2)	—	—	Ozone ISA[3]
	Emergency department visits for asthma (all ages)	—	—	Ozone ISA[3]
	Minor restricted-activity days (age 18–65)	—	—	Ozone ISA[3]
	School absence days (age 5–17)	—	—	Ozone ISA[3]
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[3]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,4]
Reduced incidence of morbidity from exposure to HAP	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS[2,3]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[3]
	Visibility in residential areas	—	—	PM ISA[3]
Reduced effects from PM deposition (organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[3]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[3]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[3]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[3]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]

[1] The global climate and related impacts of CO_2 and CH_4 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CO_2 and SC-CH_4. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in CO_2 emissions.

[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

[3] We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

[4] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

4.2 Emission Reductions from the Final NSPS

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for methane, VOC, and HAP, including wells, wellsites, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing this rule, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how this rule might affect attainment status without air quality modeling data.[24] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources.[25] By contrast, the emission reductions for implementation rules, including this rule, are generally from a specific class of well-characterized sources. In general, the EPA is more confident in the magnitude and location of the emission reductions for implementation rules rather than illustrative NAAQS analyses. Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining future NAAQS.

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[24] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

[25] NAAQS RIAs hypothesize, but do not predict, the control strategies States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, some costs and benefits estimated in this RIA may account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

Table 4-2 shows the direct emissions reductions anticipated for this rule, across the regulatory options examined. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone and reducing these emissions would reduce exposure to these secondary pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas, and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 4-2 Direct Emission Reductions across NSPS Regulatory Options in 2020 and 2025

Pollutant	Option 1	Option 2 (Final)	Option 3
		2020	
Methane (short tons/year)	250,000	300,000	350,000
VOC (short tons/year)	130,000	150,000	160,00
HAP (short tons/year)	1,300	1,900	2,400
Methane (metric tons)	230,000	280,000	320,000
Methane (million metric tons CO_2 Eq.)	5.6	6.9	8.0
		2025	
Methane (short tons/year)	390,000	510,000	610,000
VOC (short tons/year)	170,000	210,000	230,000
HAP (short tons/year)	2,700	3,900	5,000
Methane (metric tons)	360,000	460,000	550,000
Methane (million metric tons CO_2 Eq.)	8.9	11	14

4.3 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.97 W/m^2 of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions.

The oil and gas category emits significant amounts of methane. The public Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt CO_2 Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2 Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016c).

Actions taken to comply with the NSPS are anticipated to significantly decrease methane emissions from the oil and natural gas sector in the United States. The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons CO_2 Eq. in 2020 and by about 12 million metric tons CO_2 Eq. in 2025. It is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; however, the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking. To give a sense of the magnitude of the reductions, the methane reductions estimated for 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the U.S. GHG Inventory for 2014 (about 232 million metric tons CO_2 Eq. are from petroleum and natural gas production and gas processing, transmission, and storage). Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of reductions from total emissions in 2020 and 2025.

We calculated the global social benefits of methane emissions reductions expected from the NSPS using estimates of the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The SC-CH_4 estimates applied in this analysis were developed by Marten *et al.* (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC-CO_2), provides important context for understanding the Marten *et al.* SC-CH_4 estimates. Estimates of the SC-CO_2 have been used by the EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar the SC-CH_4 includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.

The SC-CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO_2 Technical Support Document (2010 SC-CO_2 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[26]

One key methodological aspect discussed in the SC-CO_2 TSDs is the global scope of the estimates. The SC-CO_2 estimates represent global measures because of the distinctive nature of the climate change, which is highly unusual in at least three respects. First, emissions of most GHGs contribute to damages around the world independent of the country in which they are emitted. The SC-CO_2 must therefore incorporate the full (global) damages caused by GHG emissions to address the global nature of the problem. Second, the U.S. operates in a global and highly interconnected economy, such that impacts on the other side of the world can affect our economy. This means that the true costs of climate change to the U.S. are larger than the direct impacts that simply occur within the U.S. Third, climate change represents a classic public goods problem because each country's reductions benefit everyone else and no country can be excluded from enjoying the benefits of other countries' reductions, even if it provides no reductions itself. In this situation, the only way to achieve an economically efficient level of emissions reductions is for countries to cooperate in providing mutually beneficial reductions beyond the level that would be justified only by their own domestic benefits. In reference to the public good nature of mitigation and its role in foreign relations, thirteen prominent academics noted that these "are compelling reasons to focus on a global SCC" (Pizer et al., 2014). In addition, the IWG recently noted that there is no bright line between domestic and global damages. Adverse impacts on other countries can have spillover effects on the United States, particularly in the areas of national security, international trade, public health and humanitarian concerns.[27]

The 2010 SC-CO_2 TSD also noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently IAMs do not assign value to all of the important physical, ecological, and economic

[26] Both the 2010 SC-CO_2 TSD and the current SC-CO_2 TSD are available at: <https://www.whitehouse.gov/omb/oira/social-cost-of-carbon>

[27] See Response to Comments: Social Cost of Carbon For Regulatory Impact Analysis Under Executive Order 12866, July 2015, page 31, at <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>

impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research.[28] The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SC-CO_2 estimates, though taken together they suggest that the SC-CO_2 estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007), which was the most current IPCC assessment available at the time of the IWG's 2009-2010 review, concluded that "It is very likely that [SC-CO_2 estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Since then, the peer-reviewed literature has continued to support this conclusion. For example, the IPCC Fifth Assessment report (2014) observed that SC-CO_2 estimates continue to omit various impacts, such as "the effects of the loss of biodiversity among pollinators and wild crops on agriculture."[29] Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. The new versions of the models offer some improvements in these areas, although further work is warranted.

Accordingly, the EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. The EPA and other agencies also continue to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings that use the SC-CO_2 in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO_2 methodology used by the IWG. In addition, OMB sought public

[28] Climate change impacts and social cost of greenhouse gases modeling is an area of active research. For example, see: (1) Howard, Peter, "Omitted Damages: What's Missing from the Social Cost of Carbon." March 13, 2014, http://costofcarbon.org/files/Omitted_Damages_Whats_Missing_From_the_Social_Cost_of_Carbon.pdf; and (2) Electric Power Research Institute, "Understanding the Social Cost of carbon: A Technical Assessment," October 2014, www.epri.com.

[29] Oppenheimer, M., M. Campos, R.Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

comment on the approach used to develop the $SC\text{-}CO_2$ estimates through a separate comment period and published a response to those comments in 2015.[30]

After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the $SC\text{-}CO_2$ estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans in July 2015 to obtain expert independent advice from the National Academies of Sciences, Engineering and Medicine to ensure that the $SC\text{-}CO_2$ estimates continue to reflect the best available scientific and economic information on climate change.[31] The Academies then convened a committee, "Assessing Approaches to Updating the Social Cost of Carbon," (Committee) that is reviewing the state of the science on estimating the $SC\text{-}CO_2$, and will provide expert, independent advice on the merits of different technical approaches for modeling and highlight research priorities going forward. While the Committee's review focuses on the $SC\text{-}CO_2$ methodology, recommendations on how to update many of the underlying modeling assumptions will also likely pertain to the $SC\text{-}CH_4$ estimates. EPA will evaluate its approach based upon any feedback received from the Academies' panel.

To date, the Committee has released an interim report, which recommended against doing a near term update of the $SC\text{-}CO_2$ estimates. For future revisions, the Committee recommended the IWG move efforts towards a broader update of the climate system module consistent with the most recent, best available science, and also offered recommendations for how to enhance the discussion and presentation of uncertainty in the $SC\text{-}CO_2$ estimates. Specifically, the Committee recommended that "the IWG provide guidance in their technical support documents about how [$SC\text{-}CO_2$] uncertainty should be represented and discussed in individual regulatory impact analyses that use the [$SC\text{-}CO_2$]" and that the technical support document for each update of the estimates present a section discussing the uncertainty in the overall approach, in the models used, and uncertainty that may not be included in the estimates.[32] At the time of this writing, the IWG

[30] See <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>.

[31] The Academies' review will be informed by public comments and focus on the technical merits and challenges of potential approaches to improving the $SC\text{-}CO_2$ estimates in future updates.See <https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>.

[32] National Academies of Sciences, Engineering, and Medicine. (2016). *Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update*. Committee on Assessing Approaches to Updating the Social Cost of Carbon, Board on Environmental Change and Society. Washington, DC: The National Academies Press. doi: 10.17226/21898. See Executive Summary, page 1, for quoted text.

is reviewing the interim report and considering the recommendations. EPA looks forward to working with the IWG to respond to the recommendations and will continue to follow IWG guidance on SC-CO_2.

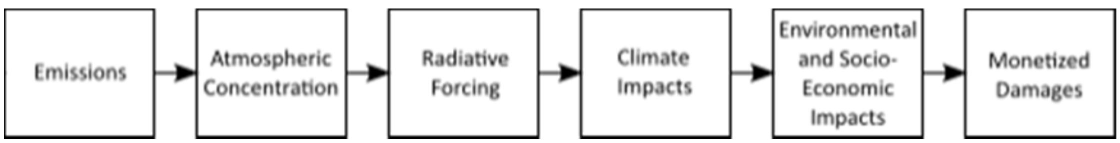
The four SC-CO_2 estimates are: $13, $45, $67, and $130 per metric ton of CO_2 emissions in the year 2020 (2012 dollars).[33] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the SC-CO_2 for several discount rates are included because the literature shows that the SC-CO_2 is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 across all three models at a 3 percent discount rate. It is included to represent lower probability but higher -impact outcomes from climate change, which are captured further out in the tail of the SC-CO_2 distribution, and while less likely than those reflected by the average SC-CO2 estimates, would be much more harmful to society and therefore, are relevant to policy makers. The SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

A challenge particularly relevant to this analysis is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC-CO_2 estimates were developed. One alternative approach to value methane impacts is to use the global warming potential (GWP) to convert the emissions to CO_2 equivalents which are then valued using the SC-CO_2 estimates.

The GWP measures the cumulative radiative forcing from a perturbation of a non-CO_2 GHG relative to a perturbation of CO_2 over a fixed time horizon, often 100 years. The GWP mainly reflects differences in the radiative efficiency of gases and differences in their atmospheric lifetimes. While the GWP is a simple, transparent, and well-established metric for

[33] The current version of the SC-CO_2 TSD is available at: <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf>. The TSDs present SC-CO_2 in $2007. The estimates were adjusted to 2012$ using the GDP Implicit Price Deflator (1.0804). Also available at: <http://www.bea.gov/iTable/index_nipa.cfm>. The SC-CO_2 values have been rounded to two significant digits. Unrounded numbers from the 2013 SCC TSD were adjusted to 2012$ and used to calculate the CO_2 benefits.

assessing the relative impacts of non-CO_2 emissions compared to CO_2 on a purely physical basis, there are several well-documented limitations in using it to value non-CO_2 GHG benefits, as discussed in the 2010 SC-CO_2 TSD and previous rulemakings (e.g., U.S. EPA 2012b, 2012d).[34] In particular, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases (Marten and Newbold, 2012; Marten et al. 2014; and Waldhoff et al al. 2014). Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO_2 GHG emissions relative to CO_2 at a specific point along the pathway from emissions to monetized damages (depicted in Figure 4-1), and this point may differ across measures.



Source: Marten *et al.* 2014

Figure 4-1 Path from GHG Emissions to Monetized Damages

The GWP is not ideally suited for use in benefit-cost analyses to approximate the social cost of non-CO_2 GHGs because it ignores important nonlinear relationships beyond radiative forcing in the chain between emissions and damages. These can become relevant because gases have different lifetimes and the SC-CO_2 takes into account the fact that marginal damages from an increase in temperature are a function of existing temperature levels. Another limitation of gas comparison metrics for this purpose is that some environmental and socioeconomic impacts are not linked to all of the gases under consideration, or radiative forcing for that matter, and will therefore be incorrectly allocated. For example, the economic impacts associated with increased agricultural productivity due to higher atmospheric CO_2 concentrations included in the SC-CO_2 would be incorrectly allocated to methane emissions with the GWP-based valuation approach.

Also of concern is the fact that the assumptions made in estimating the GWP are not consistent with the assumptions underlying SC-CO_2 estimates in general, and the SC-CO_2 estimates developed by the IWG more specifically. For example, the 100-year time horizon usually used in estimating the GWP is less than the approximately 300-year horizon the IWG

[34] See also Reilly and Richards, 1993; Schmalensee, 1993; Fankhauser, 1994; Marten and Newbold, 2012.

used in developing the $SC\text{-}CO_2$ estimates. The GWP approach also treats all impacts within the time horizon equally, independent of the time at which they occur. This is inconsistent with the role of discounting in economic analysis, which accounts for a basic preference for earlier over later gains in utility and expectations regarding future levels of economic growth. In the case of methane, which has a relatively short lifetime compared to CO_2, the temporal independence of the GWP could lead the GWP approach to underestimate the $SC\text{-}CH_4$ with a larger downward bias under higher discount rates (Marten and Newbold, 2012).[35]

The EPA sought public comments on the valuation of non-CO_2 GHG impacts in previous rulemakings (e.g., U.S. EPA 2012b, 2012d). In general, the commenters strongly encouraged the EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis, however they noted the challenges associated with the GWP-approach, as discussed above, and encouraged the use of directly-modeled estimates of the $SC\text{-}CH_4$ to overcome those challenges.

The EPA had cited several researchers that had directly estimated the social cost of non-CO_2 emissions using IAMs but noted that the number of such estimates was small compared to the large number of $SC\text{-}CO_2$ estimates available in the literature. The EPA found considerable variation among these published estimates in terms of the models and input assumptions they employ (U.S. EPA, 2012d)[36]. These studies differed in the emissions perturbation year, employed a wide range of constant and variable discount rate specifications, and considered a range of baseline socioeconomic and emissions scenarios that have been developed over the last 20 years. Furthermore, at the time, none of the other published estimates of the social cost of non-CO_2 GHG were consistent with the $SC\text{-}CO_2$ estimates developed by the IWG, and most were likely underestimates due to changes in the underlying science since their publication.

Therefore, the EPA concluded in those rulemaking analyses that the GWP approach would serve as an interim method of analysis until directly modeled social cost estimates for non-CO_2 GHGs, consistent with the $SC\text{-}CO_2$ estimates developed by the IWG, were developed.

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[35] We note that the truncation of the time period in the GWP calculation could lead to an overestimate of $SC\text{-}CH_4$ for near term perturbation years when the $SC\text{-}CO_2$ is based on a sufficiently low or steeply declining discount rate.

[36] The researchers cited U.S. EPA 2012d include: Fankhauser (1994); Kandlikar (1995); Hammitt et al. (1996); Tol et al. (2003); Tol (2004); and Hope and Newberry (2006).

The EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefit-cost analyses.[37]

Since then, a paper by Marten *et al.* (2014) provided the first set of published SC-CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO_2 estimates.[38] Specifically, the estimation approach Marten *et al.* used incorporated the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO_2 estimates. The aggregation method involved distilling the 45 distributions of the SC-CH_4 produced for each emissions year into four estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3 percent discount rate. Marten et al. also used the same rationale as the IWG to develop global estimates of the SC-CH_4, given that methane is a global pollutant.

In addition, the atmospheric lifetime and radiative efficacy of methane used by Marten *et al.* is based on the estimates reported by the IPCC in their Fourth Assessment Report (AR4, 2007), including an adjustment in the radiative efficacy of methane to account for its role as a precursor for tropospheric ozone and stratospheric water. These values represent the same ones used by the IPCC in AR4 for calculating GWPs. At the time Marten *et al.* developed their estimates of the SC-CH_4, AR4 was the latest assessment report by the IPCC. The IPCC updates GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest estimate of the methane GWP ranged from 28-36, compared to a GWP of 25 in AR4. The updated values reflect a number of changes: changes in the lifetime and radiative efficiency estimates for CO_2, changes in the lifetime estimate for methane, and changes in the correction

[37] For example, the 2012 New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry are expected to reduce methane emissions by 900,000 metric tons annually, see <http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf>. Additionally, the 2017-2025 Light-duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, promulgated jointly with the National Highway Traffic Safety Administration, is expected to reduce methane emissions by over 100,000 metric tons in 2025 increasing to nearly 500,000 metric tons in 2050, see <http://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf>.

[38] Marten *et al.* (2014) also provided the first set of SC-N_2O estimates that are consistent with the assumptions underlying the SC-CO_2 estimates.

factor applied to methane's GWP to reflect the effect of methane emissions on other climatically important substances such as tropospheric ozone and stratospheric water vapor. In addition, the range presented in the latest IPCC report reflects different choices regarding whether to account for climate feedbacks on the carbon cycle for both methane and CO_2 (rather than just for CO_2 as was done in AR4).[39,40]

Marten *et al.* (2014) discuss these estimates, (SC-CH_4 estimates presented below in Table 4-3), and compare them with other recent estimates in the literature.[41] The authors noted that a direct comparison of their estimates with all of the other published estimates is difficult, given the differences in the models and socioeconomic and emissions scenarios, but results from three relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and Newbold (2012), Waldhoff *et al.* (2014)). Marten *et al.* found that, in general, the SC-CH_4 estimates from their 2014 paper are higher than previous estimates. The higher SC-CH_4 estimates are partially driven by the higher effective radiative forcing due to the inclusion of indirect effects from methane emissions in their modeling. Marten *et al.*, similar to other recent studies, also find that their directly modeled SC-CH_4 estimates are higher than the GWP-weighted estimates. More detailed discussion of the SC-CH_4 estimation methodology, results and a comparison to other published estimates can be found in Marten *et al.*

[39] *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[40] Note that this analysis uses a GWP value for methane of 25 for CO_2 equivalency calculations, consistent with the GHG emissions inventories and the IPCC Fourth Assessment Report (AR4).

[41] Marten *et al.* (2014) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using National Income and Product Accounts Tables, Table 1.1.9, Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), <http://www.bea.gov/iTable/index_nipa.cfm> (1.0804) Accessed 3/3/15.

Table 4-3 Social Cost of Methane ($SC-CH_4$), 2012 – 2050[a] [in 2012$ per metric ton] (Source: Marten *et al.*, 2014[b])

Year	$SC-CH_4$			
	5 Percent Average	3 Percent Average	2.5 Percent Average	3 Percent 95th percentile
2012	$430	$1,000	$1,400	$2,800
2015	$490	$1,100	$1,500	$3,000
2020	$580	$1,300	$1,700	$3,500
2025	$700	$1,500	$1,900	$4,000
2030	$820	$1,700	$2,200	$4,500
2035	$970	$1,900	$2,500	$5,300
2040	$1,100	$2,200	$2,800	$5,900
2045	$1,300	$2,500	$3,000	$6,600
2050	$1,400	$2,700	$3,300	$7,200

[a] The values are emissions-year specific and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.
[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the $SC-CO_2$ estimates described above. See Corrigendum to Marten *et al*. (2014) for more details <http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550 >.

The application of directly modeled estimates from Marten *et al.* (2014) to benefit-cost analysis of a regulatory action is analogous to the use of the $SC-CO_2$ estimates. Specifically, the $SC-CH_4$ estimates in Table 4-3 are used to monetize the benefits of reductions in methane emissions expected as a result of the rulemaking. Forecasted changes in methane emissions in a given year, expected as a result of the regulatory action, are multiplied by the $SC-CH_4$ estimate for that year. To obtain a present value estimate, the monetized stream of future non-CO_2 benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-CO_2 GHG emission changes. In addition, the limitations for the $SC-CO_2$ estimates discussed above likewise apply to the $SC-CH_4$ estimates, given the consistency in the methodology.

In early 2015, the EPA conducted a peer review of the application of the Marten *et al.* (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application.[42] Three reviewers considered seven charge questions that covered

[42] For a copy of the peer review responses, see Docket ID EPA-HQ-OAR-2010-0505-5016. Also available at <https://cfpub.epa.gov/si/si_public_pra_view.cfm?dirEntryID=291976> (see "SCCH4 EPA PEER REVIEW FILES.PDF").

issues such as the EPA's interpretation of the Marten *et al.* estimates, the consistency of the estimates with the SC-CO_2 estimates, the EPA's characterization of the limits of the GWP-approach to value non-CO_2 GHG impacts, and the appropriateness of using the Marten *et al.* estimates in regulatory impact analyses. The reviewers agreed with the EPA's interpretation of Marten *et al.*'s estimates, generally found the estimates to be consistent with the SC-CO_2 estimates, and concurred with the limitations of the GWP approach, finding directly modeled estimates to be more appropriate. While outside of the scope of the review, the reviewers briefly considered the limitations in the SC-CO_2 methodology (e.g., those discussed earlier in this section) and noted that because the SC-CO_2 and SC-CH_4 methodologies are similar, the limitations also apply to the resulting SC-CH_4 estimates. Two of the reviewers concluded that use of the SC-CH_4 estimates developed by Marten *et al.* and published in the peer-reviewed literature is appropriate in RIAs, provided that the Agency discuss the limitations, similar to the discussion provided for SC-CO_2 and other economic analyses. All three reviewers encouraged continued improvements in the SC-CO_2 estimates and suggested that as those improvements are realized they should also be reflected in the SC-CH_4 estimates, with one reviewer suggesting the SC-CH_4 estimates lag this process. The EPA supports continued improvement in the SC-CO_2 estimates developed by the U.S. government and agrees that improvements in the SC-CO_2 estimates should also be reflected in the SC-CH_4 estimates. The fact that the reviewers agree that the SC-CH_4 estimates are generally consistent with the SC-CO_2 estimates that are recommended by OMB's guidance on valuing CO_2 emissions reductions, leads the EPA to conclude that use of the SC-CH_4 estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis.

The EPA also carefully considered the full range of public comments and associated technical issues on the Marten et al. SC-CH_4 estimates received through this rulemaking and determined that it would continue to use the estimates in the final rulemaking analysis. Based on the evaluation of the public comments on this rulemaking, the favorable peer review of the Marten et al. application, and past comments urging the EPA to value non-CO_2 GHG impacts in its rulemakings, the EPA concluded that the estimates represent the best scientific information on the impacts of climate change available in a form appropriate for incorporating the damages from incremental methane emissions changes into regulatory analysis. The Agency has valued the methane benefits expected from this rulemaking using the Marten *et al.* (2014) SC-CH_4 estimates and has included those benefits in the main benefits analysis. Please see the Response to Comments document, section XIII-H-4, for EPA's detailed responses to the comments on methane valuation.

The estimated methane benefits are presented in Table 4-4 below for years 2020 and 2025 across regulatory options. Applying this approach to the methane reductions estimated for the final NSPS option (Option 2), the 2020 methane benefits vary by discount rate and range from about $160 million to approximately $950 million; the mean SC-CH_4 at the 3 percent discount rate results in an estimate of about $360 million in 2020. The methane benefits increase for Option 2 in 2025 and likewise vary by discount rate, ranging from about $320 million to approximately $1.8 billion in that year; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $690 million in 2025.

Table 4-4 Estimated Global Benefits of Methane Reductions* (in millions, 2012$)

Discount rate and statistic	Option 1		Option 2 (final)		Option 3	
	2020	2025	2020	2025	2020	2025
Million metric tonnes of methane reduced	0.23	0.36	0.28	0.46	0.32	0.55
Million metric tonnes of CO_2 Eq.	5.6	8.9	6.9	11	8.0	14
5% (average)	$130	$250	$160	$320	$190	$390
3% (average)	$290	$540	$360	$690	$420	$840
2.5% (average)	$390	$690	$480	$890	$560	$1,100
3% (95th percentile)	$780	$1,400	$950	$1,800	$1,100	$2,200

*The SC-CH_4 values are dollar-year and emissions-year specific. SC-CH_4 values represent only a partial accounting of climate impacts.

The vast majority of this rule's climate-related benefits are associated with methane reductions, but some climate-related impacts are expected from the rule's secondary air impacts. The secondary impacts are discussed in Section 4.7.

Methane is also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2013). Approximately 40 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (HTAP, 2010). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (HTAP, 2010). Unlike NO_X and VOCs, which affect ozone concentrations regionally and at time scales of hours to days, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime (HTAP, 2010). Reducing methane emissions, therefore, can reduce global background ozone concentrations, human exposure to ozone, and the incidence of ozone-related health effects (West *et al.*, 2006, Anenberg *et al.*, 2009). These benefits are global and occur in both urban and rural areas. Reductions in background ozone concentrations can also have benefits for agriculture and ecosystems (UNEP/WMO, 2011). Studies show that controlling methane emissions can reduce global ozone concentrations and climate change simultaneously. But, controlling other shorter-lived ozone precursors such as NO_X, carbon monoxide, or non-methane VOCs have larger local health benefits from greater reductions in local ozone concentrations (West and Fiore, 2005; West *et al.*, 2006; Fiore *et al.*, 2008; Dentener *et al.*, 2005; Shindell *et al.*, 2005, 2012; UNEP/WMO, 2011). The health, welfare, and climate effects associated with ozone are described in the preceding sections.

A paper was published in the peer-reviewed scientific literature that presented a range of estimates of the monetized ozone-related mortality benefits of reducing methane emissions (Sarofim *et al.* 2015). For example, under their base case assumptions using a 3% discount rate, Sarofim *et al*. find global ozone-related mortality benefits of methane emissions reductions to be $790 per tonne of methane in 2020, with 10.6%, or $80, of this amount resulting from mortality reductions in the United States. The methodology used in this study is consistent in some (but not all) aspects with the modeling underlying the SC-CO_2 and SC-CH_4 estimates discussed above, and required a number of additional assumptions such as baseline mortality rates and mortality response to ozone concentrations. The proposal requested comment on the application of the Sarofim *et al.* (2015) for this benefits analysis as an approach to estimating the ozone related mortality benefits resulting from the methane reductions expected from this rulemaking. Some commenters objected to the inclusion of these benefits because they argue that methane is not a VOC, whereas one commenter agreed that there is a connection between methane emissions, higher ozone levels, and therefore human mortality. While the EPA does consider the methane impacts on ozone to be important, there remain unresolved questions regarding several methodological choices involved in applying the Sarofim *et al.* (2015) approach in the context of an EPA benefits analysis, and therefore the EPA is not including a quantitative analysis of this effect in this rule at this time.

4.4 VOC as a $PM_{2.5}$ Precursor

This rulemaking would reduce emissions of VOC, which are a precursor to $PM_{2.5}$. Most VOC emitted are oxidized to CO_2 rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory, it is unlikely this sector has a large contribution to ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform the air quality modeling needed to quantify $PM_{2.5}$ benefits associated with reducing VOC emissions for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient $PM_{2.5}$ levels without air quality modeling. However, we provide the discussion below for context regarding findings from previous modeling.

4.4.1 $PM_{2.5}$ Health Effects and Valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, the EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2011g)). These health effects include premature mortality for adults and infants; cardiovascular morbidity, such as heart attacks; respiratory morbidity, such as asthma attacks and acute and chronic bronchitis; which result in hospital and ER visits, lost work days, restricted activity days, and respiratory symptoms. Although the EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

When the EPA quantifies $PM_{2.5}$-related benefits, the agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Fann, Fulcher, and Hubbell (2009) examined how the monetized benefit-per-ton estimates of reducing ambient $PM_{2.5}$ varies by the location of the emission reduction, the type of source emitting the precursor, and the specific precursor controlled. This study employed a reduced form air quality model to estimate changes in ambient $PM_{2.5}$ from reducing 12 different combinations of precursor emissions and emission sources, including reducing directly emitted carbonanecous particles, nitrogen oxides, sulfur oxides, ammonia, and VOCs for nine urban areas and nationwide. For each precursor/source combination in each location, the study authors then estimated the total monetized health benefits associated with the $PM_{2.5}$ change and divided these benefits by the corresponding emissions changes to generate benefit-per-ton estimates.The estimates from this study can provide general context for the unquantified VOC benefits in this rulemaking. Specifically, Fann, Fulcher, and Hubbell (2009) found that the monetized benefit-per-ton of reducing VOC emissions ranged from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOC, from the Laden *et al.* (2006) mortality function (based on the Harvard Six Cities study, a large cohort epidemiology study in the Eastern U.S., an analysis year of 2015, a 3 percent discount rate, and 2006$). Additional benefit-per-ton estimates are available from this dataset using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and those supplied by experts (e.g., Pope *et al.*, 2002; Laden *et al.*, 2006; Roman *et al.*, 2008). The EPA generally presents a range of benefits estimates derived from the American Cancer Society cohort (e.g., Pope *et al.*, 2002; Krewski *et al.*, 2009) to the Harvard Six Cities cohort (e.g., Laden *et al.*, 2006; Lepuele *et al.*, 2012) because the studies are both well-designed and extensively peer reviewed. The EPA provides the benefit estimates derived from expert opinions in Roman *et al.* (2008) as a characterization of uncertainty. As shown in Table 4-5, the range of VOC benefits that reflect the range of epidemiology studies and the range of the urban areas is $300 to $7,500 per ton of VOC reduced (2012$).[43] Since these estimates were presented in the 2012 Oil and Gas NSPS RIA (U.S. EPA, 2012b), we updated our methods to apply more recent epidemiological studies for these cohorts (i.e., Krewski *et al.*, 2009; Lepuele *et al.*, 2012) as well as additional updates to the morbidity studies and population data.[44] Because these updates would not lead to significant changes in the benefit-per-ton estimates for VOC, we have not updated them here.

While these ranges of benefit-per-ton estimates provide general context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$, these factors lead the EPA to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of this rule, even as a bounding exercise.

[43] We also converted the estimates from Fann, Fulcher, and Hubbell (2009) to 2012$ and applied EPA's current value of a statistical life (VSL) estimate. For more information regarding EPA's current VSL estimate, please see Section 5.6.5.1 of the RIA for the PM NAAQS RIA (U.S. EPA, 2012c). EPA continues to work to update its guidance on valuing mortality risk reductions.

[44] For more information regarding these updates, please see Section 5.3 of the RIA for the final PM NAAQS (U.S. EPA, 2012c).

Table 4-5 Monetized Benefits-per-Ton Estimates for VOC in 9 Urban Areas and Nationwide based on Fann, Fulcher, and Hubbell (2009) in (2012$)

Area	Pope *et al.* (2002)	Laden *et al.* (2006)	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$660	$1,600	$1,700	$1,300	$1,300	$920	$2,100	$1,200	$780	$980	$1,300	$1,000	$260	$1,000
Chicago	$1,600	$4,000	$4,200	$3,300	$3,200	$2,300	$5,300	$3,000	$1,900	$2,400	$3,200	$2,600	$640	$2,500
Dallas	$320	$790	$830	$650	$630	$450	$1,000	$580	$380	$480	$630	$510	$130	$490
Denver	$770	$1,900	$2,000	$1,500	$1,500	$1,100	$2,400	$1,400	$910	$1,100	$1,500	$1,200	$300	$910
NYC/ Philadelphia	$2,300	$5,600	$5,900	$4,600	$4,500	$3,200	$7,300	$4,100	$2,700	$3,400	$4,500	$3,600	$890	$3,300
Phoenix	$1,100	$2,700	$2,800	$2,200	$2,100	$1,500	$3,500	$2,000	$1,300	$1,600	$2,100	$1,700	$420	$1,600
Salt Lake	$1,400	$3,300	$3,500	$2,700	$2,700	$1,900	$4,400	$2,500	$1,600	$2,000	$2,700	$2,200	$570	$2,100
San Joaquin	$3,100	$7,500	$7,900	$6,100	$6,000	$4,300	$9,700	$5,500	$3,600	$4,500	$6,000	$4,900	$1,400	$4,600
Seattle	$300	$730	$770	$570	$590	$420	$950	$540	$350	$440	$580	$470	$120	$350
National average	**$1,300**	**$3,200**	**$3,400**	**$2,600**	**$2,600**	**$1,800**	**$4,200**	**$2,300**	**$1,500**	**$1,900**	**$2,500**	**$2,100**	**$520**	**$1,900**

* The estimates in this table provide general context regarding the potential magnitude of monetized benefits from reducing VOC emissions, but these urban areas were not chosen based on the locations of VOC emissions from the oil and gas sector. Coupled with other uncertainties, these VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of this rule. These estimates assumed a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been adjusted from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and the EPA's current VSL estimate. However, these estimates have not been updated to reflect recent epidemiological studies for mortality studies, morbidity studies, or population data. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase theVOC benefit-per-ton estimates by approximately 13 percent. Assuming a 25 percent reduction in VOC emissions would decrease the VOC benefit-per-ton estimates by 13 percent. The EPA generally presents a range of benefits estimates derived from the expert functions from Roman *et al.* (2008) as a characterization of uncertainty.

4.4.2 Organic PM Welfare Effects

According to the previous residual risk assessment for this sector (U.S. EPA, 2012a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a). This summary is from section 6.6.1 of the 2012 PM NAAQS RIA (U.S. EPA, 2012c).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers *et al.*, 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.4.3 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ from VOC emissions would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2011a; U.S. EPA, 2011g; U.S. EPA, 2012c) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.5 VOC as an Ozone Precursor

This rulemaking would reduce emissions of VOC, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NO_X), react in the presence of sunlight. In urban areas, compounds representing all classes of VOC are important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a, 2014b). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate, particularly for sectors with substantial new growth. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOC. Rural areas and downwind suburban areas are often NO_X-limited, which means that ozone concentrations are most effectively reduced by lowering NO_X emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NO_X and VOC.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform air quality modeling for this rule needed to quantify the ozone benefits associated with reducing VOC emissions. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions and data limitations regarding the location of new and modified wellsites, we are unable to estimate the effect that reducing VOC will have on ambient ozone concentrations without air quality modeling.

4.5.1 Ozone Health Effects and Valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2013). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. The scientific literature is also suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOC from industrial boilers resulted in $3.6 to $15 million (2008$) of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[45] After updating the currency year to 2012$, this implies a

[45] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NO_X emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

benefit-per-ton for ozone of $260 to $1,100 per ton of VOC reduced. Since EPA conducted the analysis of industrial boilers, EPA published the *Integrated Science Assessment for Ozone* (U.S. EPA, 2013), the *Health Risk and Exposure Assessment for Ozone* (U.S. EPA, 2014a), and the RIA for the proposed Ozone NAAQS (U.S. EPA, 2014b). Therefore, the ozone mortality studies applied in the boiler analysis, while current at that time, do not reflect the most updated literature available. The selection of ozone mortality studies used to estimate benefits in RIAs was revisited in the RIA for the proposed Ozone NAAQS. Applying the more recent studies would lead to benefit-per-ton estimates for ozone within the range shown here. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those estimates to provide useful estimates of the monetized benefits of this rule, even as a bounding exercise.

4.5.2 Ozone Vegetation Effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

4.5.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing greenhouse gas (GHG) (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun’s harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming levels of increased tropospheric ozone concentrations resulting from human methane, NOx, and VOC emissions was 0.5 W/m^2, or about 30 percent as large a warming influence as elevated CO_2 concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

4.6 Hazardous Air Pollutant (HAP) Benefits

When looking at exposures from all air toxic sources of outdoor origin across the U.S., we see that emissions declined by approximately 60 percent since 1990. However, despite this decline, the 2011 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2015).[46] The levels of air toxics to which people are exposed vary depending on where they live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, the EPA conducts the NATA.[47] The most recent NATA was conducted for calendar year 2011 and was released in December 2015. NATA includes four steps:

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient concentrations of air toxics across the U.S. utilizing dispersion models

3) Estimating population exposures across the U.S. utilizing exposure models

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2011 NATA, the EPA estimates that less than 1 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 40 in a million. Nationwide, the key pollutants that contribute most to the overall

[46] The 2011 NATA is available on the Internet at http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment.

[47] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2011 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2015) 2011 National-Scale Air Toxics Assessment. <http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment>.

cancer risks are formaldehyde and benzene.[48,49] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile, biogenics, and background sources contribute lesser amounts to the remaining cancer risk.

Noncancer health effects can result from chronic,[50] subchronic,[51] or acute[52] inhalation exposure to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2011 NATA, about 80 percent of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2011 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-2 and Figure 4-3 depict the 2011 NATA estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions were more than seventeen times acrolein emissions on a national basis in the EPA's 2011 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, this results in 2011 NATA estimates of nationwide chronic respiratory noncancer risks from acrolein being over three times that of

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[48] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2011 NATA risk estimates can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

[49] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

[50] Chronic exposure is defined in the glossary of the Integrated Risk Information System (IRIS) database (<http://www.epa.gov/iris>) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10 of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[51] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10 of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[52] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

acetaldehyde.[53] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

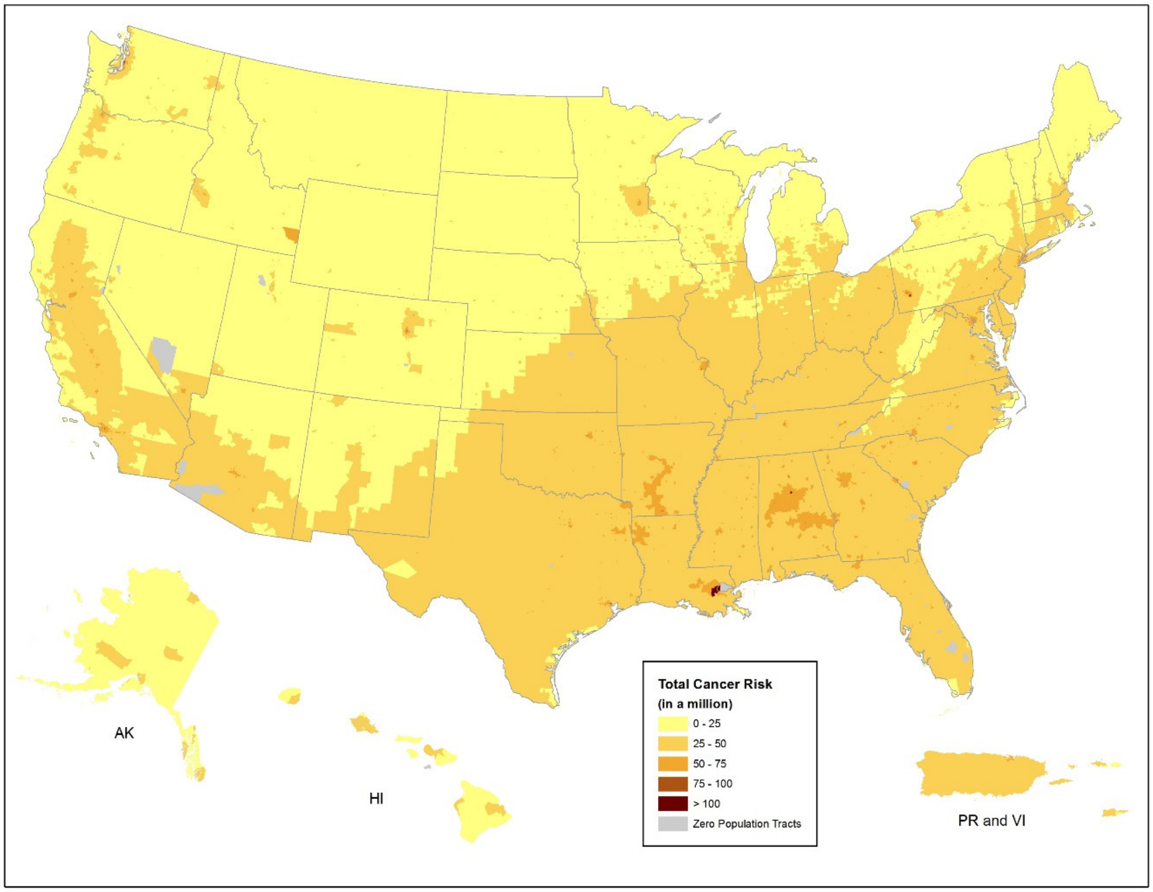

Figure 4-2 2011 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

[53] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at <http://www.epa.gov/iris>.

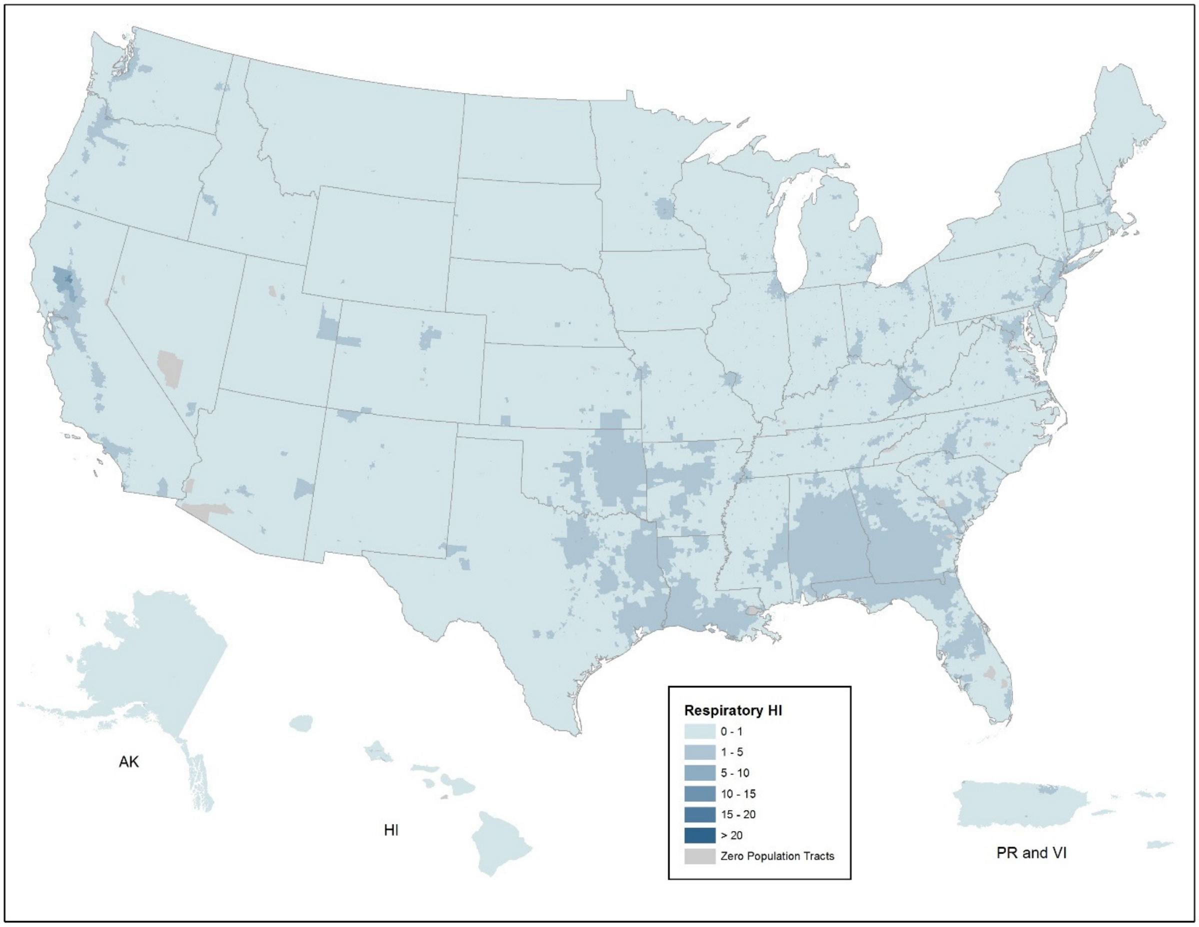

Figure 4-3 2011 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of this rule. In a few previous analyses of the benefits of reductions in HAP, EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) and reference concentrations (RfC) developed through risk assessment procedures. The URF is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant. These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious noncancer health effects during a lifetime. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAP) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn *et al.*, 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by this rule. EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2012a). In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. This rule is anticipated to avoid or reduce 3,400 tons of HAP in 2025. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

4.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[54,55,56] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human

[54] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <http://www.epa.gov/iris/subst/0276.htm>.

[55] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[56] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

Services has characterized benzene as a known human carcinogen.[57,58] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[59,60]

4.6.2 Toluene[61]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in

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[57] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[58] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: <http://ntp.niehs.nih.gov/go/16183>.

[59] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[60] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[61] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.6.3 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.[62] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[63]

4.6.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral

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[62] Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at <http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1>.

[63] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0617.htm>.

cavities in male and female rats exposed to ethylbenzene via the oral route.[64,65] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[66,67] The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.6.5 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[68] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[69] Long-term inhalation exposure to xylenes in humans has been associated with a

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[64] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[65] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[66] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

[67] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[68] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0270.htm>.

[69] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[70] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.6.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[71]

4.6.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[72]

4.7 Secondary Air Emissions Impacts

The control techniques to meet the standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. Table 4-6 shows the estimated secondary emissions associated with combustion of emissions as a result of the rule. In

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[70] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

[71] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[72] U.S. EPA Integrated Risk Information System (IRIS) database is available at: <www.epa.gov/iris>.

particular, combustion-related emissions result from the control of oil well completions (i.e., exploratory and delineation wells and development wells where RECs are infeasible and pneumatic pumps and centrifugal compressors (because the requirement for these sources is to route to control). More details on the estimation of secondary impacts for each emissions category are presented in the TSD. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant increases is small.

Table 4-6 Increases in Secondary Air Pollutant Emissions (short tons per year)

	2020				
Emissions Category	**CO_2**	**NO_X**	**PM**	**CO**	**THC**
Total Hydraulically Fractured and Re-fractured Oil Well Completions	890,000	460	17	2,500	940
Fugitive Emissions	*minimal*	*minimal*	*minimal*	*minimal*	*minimal*
Pneumatic Pumps	100,000	52	2	290	110
Pneumatic Controllers	3,900	2	0	11	4
Compressors	0	0	0	0	0
Total 2020	**1,000,000**	**510**	**19**	**2,800**	**1,100**
	2025				
Emissions Category	**CO_2**	**NO_X**	**PM**	**CO**	**THC**
Total Hydraulically Fractured and Re-fractured Oil Well Completions	950,000	490	18	2,700	1,000
Fugitive Emissions	*minimal*	*minimal*	*minimal*	*minimal*	*minimal*
Pneumatic Pumps	200,000	100	4	570	220
Pneumatic Controllers	7,800	4	0	22	8
Compressors	0	0	0	0	0
Total in 2025	**1,200,000**	**600**	**22**	**3,200**	**1,200**

The secondary emission impacts for regulatory options are equal across the options. This result holds because the only requirements varied across the options is the frequency of survey and repair requirements. Moving from Option 1 to Option 3 increases the frequency of survey and repair under the fugitive emissions requirement, and secondary emissions from the fugitive emissions requirements are expected to be minimal.

The CO_2 impacts in Table 4-6 are the emissions that are expected to occur from natural gas emissions that are captured by emissions controls and combusted. However, because of the atmospheric chemistry associated with the natural gas emissions, most of the carbon in the VOCs and CH_4 emissions expected in the absence of combustion-related emissions controls would have eventually oxidized forming CO_2 in the atmosphere and led to approximately the same long-run CO_2 concentrations as with controls.[73] Therefore, most of the impact of these CO_2 contribution to atmospheric concentrations from the flaring of CH_4 and VOC versus future oxidization is not additional to the impacts that otherwise would have occurred through the oxidation process. However, there is a shift in the timing of the contribution of atmospheric CO_2 concentration under the policy case (in which case natural gas emissions that are captured by emissions controls are combusted). In the case of VOCs, the oxidization time in the atmosphere is relatively short, on the order of hours to months, so from a climate perspective the difference between emitting the carbon immediately as CO_2 during combustion or as VOCs is expected to be negligible. In the case of CH_4, the oxidization time is on the order of a decade, so the timing of the contribution to atmospheric CO_2 concertation will differ between the baseline and policy case. Because the growth rate of the SC-CO_2 estimates are lower than their associated discount rates, the estimated impact of CO_2 produced in the future via oxidized methane from these fossil-based emissions may be less than the estimated impact of CO_2 released immediately from combusting emissions, which would imply a small disbenefit associated with the earlier release of CO_2 during combustion of the CH_4 emissions.

In the proposal RIA, the EPA solicited comment on the appropriateness of monetizing the impact of the earlier release of CO_2 due to combusting methane and VOC emissions from oil and gas sites and a new potential approach for approximating this value using the SC-CO_2. This illustrative analysis provides a method for evaluating the estimated emissions outcomes associated with destroying one metric ton of methane by combusting fossil-based emissions at oil and gas sites (flaring) and releasing the CO_2 emissions immediately versus releasing them in the future via the methane oxidation process. This illustrative analysis as provided in the proposal demonstrated that the potential disbenefits of flaring—i.e., an earlier contribution of CO_2 emissions to atmospheric concentrations –are minor compared to the benefits of flaring—i.e., avoiding the release of and associated climate impacts from CH_4 emissions. EPA did not receive any comments regarding the appropriate methodology for conducting such an analysis,

[73] The social cost of methane (SC-CH_4) used previously in this chapter to monetize the benefits of the CH_4 emissions reductions does not include the impact of the carbon in CH_4 emissions after it oxidizes to CO_2.

but did receive one comment letter that voiced general support for monetizing the secondary impacts.

In consideration of this comment while recognizing the challenges and uncertainties related to estimation of these secondary emissions impacts for this rulemaking, EPA has continued to examine this issue in the context of this regulatory analysis—i.e, the combusting of fossil-based CH_4 at oil and gas sites—and explored ways to improve this illustrative analysis. Specifically, EPA has modified the illustrative analysis by updating the oxidization process of CH_4 to be dynamic and consistent with the modeling that underlies the SC-CH_4 estimates. Also for this illustrative analysis, EPA assumed an average methane oxidation period of 12 years, consistent with the perturbation lifetime-folding time used in IPCC AR4. The estimated disbenefits associated with destroying one metric ton of methane through combustion of emissions at oil and gas sites and releasing the CO_2 emissions in 2020 instead of being released in the future via the methane oxidation process are found to be small relative to the benefits of flaring. Specifically, the disbenefit is estimated to be about \$15 per metric ton CH_4 (based on average SC-CO_2 at 3 percent) or roughly one percent of the SC-CH_4 estimate per metric ton for 2020. The analogous estimate for 2025 is \$18 per metric ton CH_4 or about one percent of the SC-CH_4 estimates per metric ton for 2025.[74,75]

[74] To calculate the CO_2 related impacts associated the complete destruction of a ton of CH_4 emissions through flaring for this illustrative application, EPA took the difference between the SC-CO_2 at the time of the flaring and the discounted value of the CO2 impacts assuming a geometric decay of CH_4 via the oxidation process with a 12 year e-folding time using the same discount rate as used to estimate the SC-CO_2. This value was then scaled by 44/16 to account for the relative mass of carbon contained in a ton of CH_4 versus a ton of CO_2. More specifically, the impacts of shifting the CO_2 impacts are calculated as

$$(44/16)\left[\text{SC-CO2}_{\tau} - \sum_{t=\tau}^{T} e^{-1/12(t-\tau)}\left(1-e^{-1/12}\right)\left(\frac{1}{1+r}\right)^{t-\tau}\text{SC-CO2}_{t}\right],$$

where $\tau\tau$ is the year the CH_4 is destroyed, r is the discount rate, and T is the time horizon of the analysis. Ideally the time horizon, T, would be sufficiently long to capture the period in which nearly all of the CH4 is expected to have been oxidized. In this analysis we use the 2100 as the time horizon, making the assumption that the SC-CO_2 remains constant after 2050, the last year for which the IWG provides estimates. This methodology improves upon the one presented at proposal by updating the oxidization process of CH_4 to be dynamic and consistent with the modeling that underlies the SC-CH_4 estimates.

[75] The EPA also calculated these estimates using additional SC-CO_2 values, specifically the average SC-CO_2 at discount rates of 5 and 2.5 percent and the 95th percentile at 3 percent. Applying these values, the estimates of the disbenefit of releasing CO_2 emissions in 2020 instead of in the future via methane oxidation ranges from \$7 to \$40 per metric ton CH_4. The corresponding estimates for 2025 range from \$9 to \$51 per metric ton CH_4.

It is important to note that there are challenges and uncertainties related to this illustrative method and estimates, which was developed to analyze secondary fossil-based emissions from combustion. For example, these dollar per ton CH_4 estimates cannot readily be applied to the total CH_4 emissions reductions presented in section 3 without additional information about the downstream outcomes associated with the recovered gas that is not flared – e.g., whether some of that captured gas going to be burned or leaked somewhere down the line.

The EPA will continue to study this issue and assess the complexities involved in estimating the net emissions effects associated with secondary fossil-based emissions, including differences in the timing of contributions to atmospheric CO_2 concentrations. Given the uncertainties related to estimating net secondary emissions effects and that the EPA has not yet received appropriate input and review on some aspects of these calculations, the EPA is not including monetized estimates of the impacts of small changes in the timing of atmospheric CO_2 concentration increases in the final benefits estimates in this RIA. The EPA will continue to follow the scientific literature on this topic and update its methodologies as warranted.

Table 4-7 provides a summary of the direct and secondary emissions changes. Based on the summary and analysis above, the net impact of both the direct and secondary impacts of this final rule would be an improvement in ambient air quality, which would reduce potency of greenhouse gas emissions, reduce exposure to various harmful pollutants, improve visibility impairment, and reduce vegetation damage.

Table 4-7 Summary of Emissions Changes (short tons per year, except where noted)

		Option 1		Option 2 (final)		Option 3	
	Pollutant	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**
Change in Direct Emissions	Methane	-250,000	-390,000	-300,000	-510,000	-350,000	-610,000
	VOC	-130,000	-170,000	-150,000	-210,000	-160,000	-230,000
	HAP	-1,300	-2,700	-1,900	-3,900	-2,400	-5,000
Secondary Emissions	CO_2	1,000,000	1,200,000	1,000,000	1,200,000	1,000,000	1,200,000
	NOx	510	600	510	600	510	600
	PM	19	22	19	22	19	22
	CO	2,800	3,200	2,800	3,200	2,800	3,200
	THC	1,100	1,200	1,100	1,200	1,100	1,200

4.8 References

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5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs across Regulatory Options

Tables 5-1 though Table 5-3 present the summary of the benefits, costs, and net benefits for the NSPS across regulatory options. Table 5-4 provides a summary of the direct and secondary emissions changes for each regulatory option.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$290 million	$540 million
Total Costs[2]	$240 million	$360 million
Net Benefits[3]	$54 million	$180 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM2.5 and ozone exposure from 130,000 tons of VOC reduced	Health effects of PM2.5 and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 1,300 tons of HAP reduced	Health effects of HAP exposure from 2,700 tons of HAP reduced
	Health effects of ozone exposure from 250,000 tons of methane	Health effects of ozone exposure from 390,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the additional benefit estimates range from $130 million to $780 million in 2020 and $250 million to $1.4 billion in 2025 for Option 1, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 5.6 million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

Table 5-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Selected Option 2 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$360 million	$690 million
Total Costs[2]	$320 million	$530 million
Net Benefits[3]	$35 million	$170 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM2.5 and ozone exposure from 150,000 tons of VOC reduced	Health effects of PM2.5 and ozone exposure from 210,000 tons of VOC reduced
	Health effects of HAP exposure from 1,900 tons of HAP reduced	Health effects of HAP exposure from 3,900 tons of HAP reduced
	Health effects of ozone exposure from 300,000 tons of methane	Health effects of ozone exposure from 510,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane ($SC\text{-}CH_4$) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CH_4$ estimates; the additional benefit estimates range from $160 million to $950 million in 2020 and $320 million to $1.8 billion in 2025 for Option 2, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

Table 5-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$420 million	$840 million
Total Costs[2]	$490 million	$880 million
Net Benefits[3]	-$75 million	-$38 million
Non-monetized Benefits	Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 160,00 tons of VOC reduced	Non-monetized climate benefits Health effects of PM2.5 and ozone exposure from 230,000 tons of VOC reduced
	Health effects of HAP exposure from 2,400 tons of HAP reduced	Health effects of HAP exposure from 5,000 tons of HAP reduced
	Health effects of ozone exposure from 350,000 tons of methane	Health effects of ozone exposure from 610,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

[1] The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the additional benefit estimates range from $190 million to $1.1 billion in 2020 and $390 million to $2.2 billion in 2025 for this more stringent option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 8 million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the NSPS are anticipated to have minor secondary disbenefits.
[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for annualizing capital costs.
[3] Estimates may not sum due to independent rounding.

A break-even analysis answers the question: "What would the benefits need to be for the benefits to exceed the costs?" While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits. For Options 1 and 2 (final selected option), the monetized climate benefits from methane emission reductions already exceed the costs, which renders a break-even analysis for these options unnecessary. For Option 3, the monetized net benefits are estimated to be -$73 million and -$37 million and the estimated VOC emission reductions are 160,000 and 230,000 tons for 2020 and 2025, respectively. Thus, a break-even analysis suggests that the VOC emissions would need to be valued at $460 per ton in 2020 and $160 per ton in 2025 for the total monetized benefits of Option 3 to exceed costs, assuming that the health benefits from HAP emission reductions and the ozone health benefits from methane emission reductions are zero. Previous assessments have shown that the $PM_{2.5}$ health benefits associated with reducing VOC emissions were valued at $300 to $7,500 per ton of VOC emissions reduced in specific urban areas and ozone health benefits from reducing VOC emissions were valued at $260 to $1,100 per ton of VOC emissions reduced. These break-even estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even point is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

Table 5-4 Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted)

		Option 1		Option 2 (final)		Option 3	
	Pollutant	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**
Reduction in Direct Emissions	Methane	-250,000	-390,000	-300,000	-510,000	-350,000	-610,000
	VOC	-130,000	-170,000	-150,000	-210,000	-160,000	-230,000
	HAP	-1,300	-2,700	-1,900	-3,900	-2,400	-5,000
Secondary Emissions	CO_2	1,000,000	1,200,000	1,000,000	1,200,000	1,000,000	1,200,000
	NOx	510	600	510	600	510	600
	PM	19	22	19	22	19	22
	CO	2,800	3,200	2,800	3,200	2,800	3,200
	THC	1,100	1,200	1,100	1,200	1,100	1,200

5.2 Uncertainties and Limitations

Throughout the RIA, we considered a number of sources of uncertainty, both quantitatively and qualitatively, regarding emissions reductions, benefits, and costs of the rule. We summarize the key elements of our discussions of uncertainty here:

- **Projection methods and assumptions:** As discussed in Section 3.4.2, over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. The large majority of impacts of the rule (completion requirements at hydraulically fractured oil well completions and fugitive emissions requirements at wellsites) are based on projections and growth rates consistent with the drilling activity in the 2015 Annual Energy Outlook. To the extent actual drilling activities diverge from the Annual Energy Outlook projections, the projected regulatory impacts estimated in this document will diverge.

- **Years of analysis:** The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period, as discussed in Section 3.4.2. While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.
- **State regulations in baseline:** In preparing the impacts analysis, the EPA reviewed state regulations and permitting requirements, as discussed in Section 3.4.2. Applicable facilities in these states with similar requirements to the final NSPS are not included in the estimates of incrementally affected facilities presented in the RIA. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements are not reflected in this RIA.
- **Wellhead natural gas prices used to estimate revenues from natural gas recovery:** The annualized compliance cost estimates presented in this RIA include revenue from natural gas recovery resulting from emissions reductions. As a result, national compliance costs depend the price of natural gas. The sensitivity of national compliance costs to assumptions about wellhead natural gas prices are examined in Section 3.5.2.
- **Monetized methane-related climate benefits:** The EPA considered the uncertainty associated with the social cost of methane (SC-CH_4) estimates, which were used to calculate the global social benefits of methane emissions reductions expected from the NSPS. The modeling underlying the development of the SC-CH_4 estimates, which is consistent with the modeling assumptions underlying the interagency working group's SC-CO_2 estimates, addressed uncertainty in several ways. For example, the analysis addressed uncertainty in following areas: differences in model structure through an

ensemble of three integrated assessment models; sensitivity of the SC-CH_4 estimates to key exogenous projections by using five different socioeconomic and emissions forecasts; and three discount rates to reflect some uncertainty about how interest rates may change over time and the possibility that climate damages are positively correlated with uncertain future economic activity. The application of four point estimates also helps reflect uncertainty. Chapter 4 of this RIA provides a comprehensive discussion about the methodology and application of the SC-CH_4 as well as consideration of several types of secondary emissions impacts, which may partially offset the direct benefits of this rule.

- **Non-monetized benefits:** Numerous categories of health, welfare, and climate benefits are not quantified and monetized in this RIA. These unquantified benefits, including benefits from reducing emissions of methane, VOCs and HAP, are described in detail in Chapter 4.

6 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

6.1 Introduction

This section includes three sets of analyses for the final NSPS:

- Energy Markets Impacts
- Final Regulatory Flexibility Analysis
- Employment Impacts

6.2 Energy Markets Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS on U.S. energy markets. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas.

A brief conceptual discussion about our energy markets impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and presenting results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain in production at the producer level for a given cost. For example, the analysis for the rule shows that performing reduced emissions completions on hydraulically-fractured oil wells would account for about 36 percent of the natural gas captured by emissions controls in 2020 and about 23 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to account for about 62 percent of the natural gas captured by emissions controls in 2020 and about 75 percent of captured natural gas in 2025. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production.

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

6.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of the U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy (DOE). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. DOE first developed NEMS in the 1980s, and the model has undergone frequent updates and significant expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

The EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at the website: http://www.eia.gov/forecasts/aeo/.

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel *et al.* 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next module after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2040. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2015.[76] The RIA baseline is consistent with that of the Annual Energy Outlook 2015, which is used extensively in Section 2 in the Industry Profile.

6.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the final rule, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore and Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2014). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern findings and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the NSPS. We are able to target additional expenditures for environmental controls required by the NSPS on new exploratory and developmental oil and gas production activities. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the rule.

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[76] Assumptions for the 2015 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/>.

While the oil production simulated by the OGSM is sent to the refining module (the Liquid Fuels Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas is transported through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

6.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Regulatory costs associated with reduced emission completions for hydraulically fractured oil well completions are added to the drilling and completion costs of oil wells in the OGSM. Other regulatory costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The additional expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells or natural gas wells. We base the per well cost estimates on the engineering costs. Because we model natural gas recovery, we do not include revenues from additional product recovery in these costs. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

In general, the cost of capital in the model will implicitly capture potential barriers to obtaining additional capital financing for the industry on average. However, the model may not fully capture heterogeneity in the cost of capital across the industry, and therefore, may not fully capture distributional impacts across the industry as a result of firm specific characterisitics that cause them to have varying access to additional capital. An additional caveat to this analysis is that the modeling does not attempt to represent potential constraints on the supply of specific capital equipment, which may or may not be binding in practice.

Table 6-1 shows the incremental compliance that accrue to new drilling projects as a result of producers having to comply with the NSPS, across sources anticipated in 2020 and

2025. We estimate those costs as a function of new wells anticipated to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify whether costs will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells.

We divide the estimated compliance costs for the given emissions point by the appropriate number of expected new crude oil and natural gas wells in the year of analysis. The result yields an approximation of per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Hydraulically fractured oil well completions and fugitives at oil and natural gas well sites differ slightly from this approach. Drilling and completion costs of new hydraulically fractured oil wells are incremented by the weighted average of the cost of performing a REC with completion combustion and completion combustion alone. The resulting cost is itself weighted by the proportion of new hydraulically fractured oil wells estimated to be affected by the regulation. Meanwhile, assuming there is an average of two wells per wells site (see TSD for more details), new oil and gas wells face an increased annual cost of one-half of implementing the well site fugitive emission requirements.

Table 6-1 Per Well Costs for Environmental Controls Entered into NEMS (2012$)

Emissions Sources/Points	Wells Applied To in NEMS	Annualized Cost per Unit (2012$)	Per Well Costs Applied in NEMS (2012$)	Natural Gas Recovery per Unit (Mcf)	Per Well Natural Gas Recovery Applied in NEMS (Mcf)
Well Completions					
Hydraulically Fractured Oil Well Completions	New Hydraulically Fractured Oil Wells	Varies[a]	$4,590	0	0
Fugitive Emissions					
Oil Production Well Sites	New Oil Wells	$2,285	$905	191[c]	38
Natural Gas Production Well Sites	New Gas Wells	$2,285	$1,101	73	18
Gathering and Boosting Stations	New Gas Wells	$25,050	$284	1,629	18
Transmission Stations	New Gas Wells	$27,370	$13	1,673	1
Storage Facilities	New Gas Wells	$42,093	$25	5,899	3
Reciprocating Compressors					
Transmission Stations	New Gas Wells	$1,748	$3	1,122	2
Storage Facilities	New Gas Wells	$2,077	$4	1,130	2
Centrifugal Compressors					
Storage Facilities	New Gas Wells	$114,146	$0	0	0
Pneumatic Controllers -					
Transmission and Storage Stations	New Gas Wells	$25	$0	144	2
Pneumatic Pumps					
Well Sites	New Wells	$774	$15	0	0
Reporting and Recordkeeping	New Wells	$6,200,000[b]	$154	0	0

[a] Since compliance costs vary across hydraulically fractured oil well completions, this table uses the weighted average costs by completion cost type.

[b] Reporting and recordkeeping costs are assumed to be equally allocated across all new wells.

[c] Natural gas recovery at oil well sites is the weighted average of the recovery expected from oil well sites and oil well (associated gas) sites. See TSD for detailed description of these model well sites.

6.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A result of controlling methane and VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right in an increment consistent with the technically achievable emissions transferred into the production stream as a result of the final NSPS. We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 6-1).

6.2.3 Energy Markets Impacts

We estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas. In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the final rule. We also present impacts over the 2020 to 2025 period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because offshore production is not affected by the NSPS and the bulk of the rule's impacts are expected to be in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 6-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

Table 6-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Successful Wells Drilled							
Natural Gas	10,490	10,501	10,481	12,200	12,145	65,896	65,785
Crude Oil	28,496	27,455	27,463	29,244	29,231	168,768	168,736
Total	**38,986**	**37,956**	**37,944**	**41,444**	**41,376**	**234,664**	**234,521**
% Change in Successful Wells Drilled from Baseline							
Natural Gas			0.19%		-0.45%		-0.17%
Crude Oil			0.03%		-0.04%		-0.02%
Total			**0.03%**		**-0.16%**		**-0.06%**

Results show that the final NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, with very slight increases both oil and natural gas wells, relative to the baseline. Meanwhile, drilling of both natural gas and crude oil wells decreases slightly in 2025, relative to the baseline. The small increase in drilling in 2020 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple periods. Crude oil drilling over the 2020 to 2025 period decreases overall but by about 30 wells total, or about 0.02 percent, relative to the baseline. Natural gas drilling, over the same period remains declines by about 110 wells total, or about 0.17 percent, relative to the baseline.

Table 6-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS.

Table 6-3 Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Domestic Production							
Natural Gas (trillion cubic feet)	22.158	26.544	26.537	28.172	28.163	164.130	164.086
Crude Oil (million bbls/day)	4.597	8.031	8.031	8.027	8.028	48.084	48.086
% Change in Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)							
Natural Gas			-0.03%		-0.03%		-0.03%
Crude Oil			0.00%		0.01%		0.00%

As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Crude oil production remains essentially unchanged in 2020 and 2025 (with changes around or less than 0.01 percent in both years), relative to the baseline. While slightly increasing over the time horizon, the overall change in crude oil production is less than 0.01 percent, relative to the baseline. Natural gas production is estimated to decrease slightly during the 2020-25 period, by around 0.03 percent, relative to the baseline.

Note this analysis estimates very little change in domestic natural gas production, despite some environmental controls anticipated in response to the rule capture natural gas that would otherwise be emitted (about 16 bcf in 2020 and 27 bcf in 2025). NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 6-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 6-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012$)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Lower 48 Average Wellhead Price							
Natural Gas (2012$ per Mcf)	2.566	4.428	4.441	5.184	5.190	4.880	4.890
Crude Oil (2012$ per barrel)	94.835	73.920	73.918	85.219	85.218	79.530	79.527
% Change in Lower 48 Average Wellhead Price from Baseline							
Natural Gas			0.29%		0.12%		0.20%
Crude Oil			0.00%		0.00%		-0.01%

Wellhead crude oil prices for onshore lower 48 production are not estimated to change meaningfully in 2020 or 2025, or over the 2020-25 period, relative to the baseline. The production-weighted average price for wellhead crude oil over the 2020 to 2025 period is not estimated to change more than 0.01 percent, relative to the baseline. Meanwhile, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly in response to the rule in 2020 by about 0.29 percent and by about 0.12 percent in 2025, relative to the baseline. The production-weighted average price for wellhead natural gas over the 2020 to 2025 period is estimated to increase by around 0.2 percent, relative to the baseline.

Table 6-5 Net Imports of Natural Gas and Crude Oil

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Net Imports							
Natural Gas (trillion cubic feet)	1.519	-2.557	-2.554	-3.502	-3.498	-18.959	-18.939
Crude Oil (million barrels/day)	8.459	5.513	5.513	6.073	6.072	5.857	5.857
% Change in Net Imports							
Natural Gas			0.12%		0.11%		0.11%
Crude Oil			0.00%		-0.02%		0.00%

Meanwhile, as shown in Table 6-5, net imports of natural gas are estimated to increase slightly in 2020 and 2025 relative to the baseline (by about 0.12 percent and 0.11 percent, respectively) relative to the baseline. Net imports of natural gas are also expected to increase by about 0.11 percent across the 2020 to 2025 period under the rule. Crude oil imports are not estimated to change in 2020 and to decrease slightly in 2025 by about 0.02 percent relative to the baseline. Over the 2020 to 2025 period, net imports of crude oil are not estimated to change in response to the rule.

6.3 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that whenever an agency publishes a final rule after a general notice of proposed rulemaking is made, it must prepare and make available a final regulatory flexibility analysis (FRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. A FRFA describes the economic impact of the rule on small entities and any significant alternatives to the rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 604 of the RFA, the EPA prepared a final regulatory flexibility analysis (FRFA) that examines the impact of the final rule on small entities along with regulatory alternatives that could minimize that impact.

Prior to publication of the proposed rule, the EPA prepared an initial regulatory flexibility analysis (IRFA) and convened a Small Business Advocacy Review (SBAR) Panel consisting of the Director of the Sector Policies & Programs Division of the EPA Office of Air Quality Planning & Standards, the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget, and the Chief Counsel for Advocacy of the Small Business Administration. The IRFA and Final SBAR Panel Report can be found in the docket to this rulemaking at EPA-HQ-OAR-2010-0505.

6.3.1 Reasons why the Action is Being Considered

The EPA is finalizing amendments to subpart OOOO due to reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator, which include implementation improvements. The EPA is also finalizing a new subpart, 40 CFR 60, subpart OOOOa, which includes: standards for greenhouse gas (GHG) emissions (in the form of limitations on methane) from certain facilities that are covered by current VOC standards in the oil and natural gas source category, and standards for GHG and VOC emissions from facilities across the source category that are currently unregulated, including hydraulically fractured oil well completions; fugitive emissions from well sites and compressor stations; pneumatic pumps; and centrifugal compressors, reciprocating compressors and pneumatic controllers in the transmission and storage segment. The EPA is including requirements for methane emissions in subpart OOOOa because methane is a GHG, and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.[77]

6.3.2 Significant Issues Raised

The EPA received comments on the proposed standards related to the potential impacts on small entities and requests for comments that were included based on the SBAR Panel

[77] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("2009 Endangerment Finding").

Recommendations. See sections VI and VIII of the preamble to the final rule and the RTC Document in Docket ID EPA-HQ-OAR-2010-0505 for more detailed responses.

Low production wells: Several commenters supported the proposed exemption of low production well sites from the fugitive monitoring requirements. Commenters noted that marginal wells generate relatively low revenue and these wells are often drilled and operated by small companies.

Response: While these commenters did provide support for the proposed low production well exemption, other commenters indicated that low production well sites have the potential to emit substantial amounts of fugitive emissions, and that a significant number of wells would be excluded from fugitive emissions monitoring based on this exemption. We did not receive data showing that low production well sites have lower emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring.

REC costs: Commenters stated that small operators have higher well completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. However, commenters did not provide specific cost information.

Response: The BSER analysis is based on the averages of nationwide data. It is possible for a small operator to have higher than the nationwide average completion costs, however, the daily completion cost provided by the commenters is not significantly different than the EPA's estimate. Therefore, we do not believe that the cost of RECs disfavor small businesses.

Phase-in period for RECs: Commenters stated that the EPA should create a compliance phase-in period of at least 6 months for the REC requirements, to accommodate small operators. Commenters stated that REC equipment is in short supply, and this will drive up REC costs.

Commenters stated that small entities lack the purchasing power of larger operators, which makes it difficult to obtain the needed equipment before the compliance period begins.

Response: We agree that complianc with the REC requirements I the final rule could be burdensome for some in the near term due to the unavailability of REC equipment. As discussed in section VI of the preamble, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplied in the near term.

Alternatives to OGI technology: Several commenters indicated that the EPA should allow alternatives to OGI technology as the cost is excessive for small operators.

Response: In the final rule, the EPA is allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We believe this alternative will alleviate some of the burden on small entities.

Basing monitoring frequency on the percentage of leaking components: Commenters indicated that using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities since a small site will have fewer fugitive emission components than a larger site. Commenters stated that smaller entities are much more likely to operate these smaller sites, and thus are more likely to have a higher frequency survey requirements under the percentage-based system.

Response: The EPA agrees that imposing a performance based monitoring schedule would require operators to develop a program that would require extensive administration to ensure compliance. We believe that the potential for a performance–based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed monitoring frequency instead of performance based monitoring.

Timing of initial fugitive monitoring periods: Commenters stated that the requirement to conduct surveys for affected facilities using OGI technology within 30 days of the well completion or within 30 days of modification is overly restrictive. Additionally, commenters stated that small operators may not be able to find vendors available to survey a small number of wells within the required timeframe. One commenter stated that contractors will be in high demand and may give scheduling preference to larger clients versus small business entities.

Response: EPA considered these and other comments and concluded that the proposed time of 30 days within a well completion or modification is not enough time to complete the necessary preparations for the initial monitoring survey. In addition, other commenters pointed out that first date of production should be the trigger, rather than the date of well completion. Therefore, for the collection of fugitive emissions components at a new or modified well site, we are finalizing that the initial monitoring survey must take place within [**insert date 1 year after publication of the final rule in the Federal Register**] or within 60 days of the startup of production, whichever is later. We believe this extended timeframe for compliance will alleviate some of the burden on smaller operators.

Third party compliance: Commenters believe that requiring third party compliance audits will be a significant burden on small entities. One commenter said that a third-party audit requirement will dramatically increase the costs of the program and have a negative competitive impact on smaller, less funded operators.

Response: While the EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance, we have explored alternatives to the independent third party verification. Specifically, the "qualified professional engineer" model was assessed to focus on the element of engineering design. The final rule requires a professional engineer certification of technical infeasibility of connecting a pneumatic pump to an existing control device, and a professional engineer design of closed vent systems. These certifications will ensure that the owner or operator has effectively assessed appropriate factors before making a claim of infeasibility and that the closed vent system is properly designed to verify that all emissions from the unit being controlled in fact reach the control device and allow for proper control. We believe this simplified approach will reduce the burden imposed on all affected facilities, including those owned by small businesses.

6.3.3 *Small Business Administration Comments*

The Chief Counsel for Advocacy of the Small Business Administration (SBA) did not file any comments in response to the proposed rule.

6.3.4 *Description and Estimate of Affected Small Entities*

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The EPA conducted this regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities.[78] The EPA identified the size of ultimate parent entities by using the SBA size threshold guidelines.[79] The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as can be seen in Table 6-6.

Table 6-6 SBA Size Standards by NAICS Code

NAICS Codes	NAICS Industry Description	Size Standards (in millions of dollars)	Size Standards (in no. of employees)
211111	Crude Petroleum and Natural Gas Extraction	-	1,250
211112	Natural Gas Liquid Extraction	-	750
213111	Drilling Oil and Gas Wells	-	1,000
213112	Support Activities for Oil and Gas Operations	$38.5	-
486110	Pipeline Transportation of Crude Oil	-	1,500
486210	Pipeline Transportation of Natural Gas	$27.5	-

Sources: U.S. Census Bureau, Statistics of U.S. Businesses, 2012. <http://www.census.gov/econ/susb/>. SBA Size Standards, 13 CFR 121. 201

We have projections of future potentially affected activities at an aggregate level, but identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. Because of these limitations, we based the analysis in this FRFA on impacts estimates for the final requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. We are able to do this because the base year activity counts for the impacts estimates (as described in the TSD)

[78] See Section 2.6 of this RIA for more information on oil and natural gas industry firm characteristics and a breakdown of firms by size at the national level.

[79] U.S. Small Business Administration (SBA). 2016. Small Business Size Standards. Effective as of February 26, 2016. See: <https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf>.

for this rule were based on detailed information for 2012 in a dataset of U.S. wells. The proprietary DrillingInfo dataset contains a variety of information including oil, condensate, and natural gas production levels, geographic locations, as well as basin and formation information, and information about owners/operators of wells, among other data fields.[80] As described in the TSD sections on hydraulically fractured and re-fractured oil well completions and fugitive emissions, we used the DrillingInfo dataset to identify and estimate all wells that were completed in 2012, as well as completions of hydraulically fracture or re-fractured oil wells.[81] We used the field called "common operator" to identify the owner/operator of all wells in this set of new or modified 2012 wells.

While the FRFA does not incorporate potential impacts from other provisions of the final NSPS, the completions and fugitive emissions provisions represent about 98 percent of the estimated compliance costs of the final NSPS in 2020 and 2025 (Table 6-7). Not incorporating impacts from other provisions in this analysis is a limitation, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the rule in its entirety.

Table 6-7 Distribution of Estimated Compliance Costs Across Sources

	Annualized Costs (With Product Recovery, 2012$)			
	2020	**2020 (%)**	**2025**	**2025 (%)**
Hydraulically-fractured and Re-fractured Oil Well Completions and Recompletions	$130,000,000	39%	$130,000,000	25%
Fugitive Emissions at Well Sites	$190,000,000	59%	$380,000,000	73%
Other Sources	$8,000,000	2%	$11,000,000	2%
Total Annualized Costs of Proposed NSPS	$320,000,000	100%	$530,000,000	100%

Note: sums may not total due to independent rounding.

To identify potentially affected entities under the NSPS, the EPA combined ownership information from the DrillingInfo dataset with information drawn from the Hoover's Inc. online

[80] DrillingInfo is a private company that provides information and analysis to the energy sector. More information is available at: http://info.drillinginfo.com.

[81] The TSD for this proposed rule provides information on this dataset of U.S. wells. Additional details on the development of this dataset can also be found in the following docketed memo: Memorandum to Mark de Figueiredo, EPA, from Casey MacQueen and Jessica Gray, ERG. "DrillingInfo Processing Methodology". August 27, 2014.

platform, which includes information about companies, such as NAICS codes, employee counts, and sales information.[82] Note that this analysis assumes that the firms performing potentially affected activities are also the firms performing activities in the future under the NSPS. While likely true for many firms, this will not be the case for all firms.

The EPA matched owner/operators from the DrillingInfo dataset to companies in a database developed from a download of oil and gas companies in Hoover's online database. The EPA matched as many records as possible. In the instances where the DrillingInfo owner/operator was not the highest level or company ownership, we recorded the highest level of owner as was identifiable in Hoovers. Linking these two datasets yields information on the NAICS, employee levels, and revenues of the owner/operators shown in the DrillingInfo dataset to have new or modified wells in 2012.

The EPA then used the NAICS codes associated with the matched owner/operators to determine which owner/operators should be considered to be small entities for this analysis, based on the SBA size standards above. That said, many DrillingInfo owner/operators had no match in Hoovers. Additionally, some Hoovers records lacked the information (employees or revenues, depending on the NAICS) needed to make a size determination. We initially classified these as an "unknown" size. See Table 6-8 for a summary of results of this matching exercise.

Table 6-8 No. of Completions in 2012 by Preliminary Firm Size

		Number of Completions, 2012	
Firm Size Performing Well Completions	**No. of Firms**	**Hydraulically Fractured or Re-fractured Oil Wells**	**All Completions**
Small	951	2,998	10,360
Not Small	150	10,674	22,866
Unknown	1,118	676	5,762
Total	**2,219**	**14,348**	**38,988**

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

[82] The Hoover's Inc. online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: <http://www.hoovers.com>.

Upon analysis of the firms of unknown size, the EPA observed that, on average, the firms of unknown size perform fewer well completions. For this reason, we made the observation that the firms of unknown size are more likely to be small than not small. To proceed with the analysis, we reclassified these firms as small, resulting in the distribution presented in the first two columns of Table 6-9.

Table 6-9 No. of Completions in 2012 by Firm Size

Firm Size Performing Well Completions	No. of Firms	No. of Completions, 2012	
		Hydraulically Fractured or Re-fractured Oil Wells	**All Completions**
Small	2,069	3,674	16,122
Not Small	150	10,674	22,866
Total	**2,219**	**14,348**	**38,988**

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

6.3.5 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by s**tate, local, tribal or t**he Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in an industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and training personnel to be able to respond to the collection of information. The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual average cost of $3,361,074. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

6.3.5.1 Methodology for Estimating Compliance Cost Impacts on Small Entities

This section describes how we project the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels, how we estimate costs at the firm level from these activity estimates, and how we estimated sales for small entities when available data on sales are incomplete.

New and modified hydraulically fractured oil well completions and well sites in this FRFA are based on the same growth rates used to project future activities as described in the TSD and are consistent with other analyses in this RIA. These growth rates are consistent with the drilling activity in the 2015 Annual Energy Outlook. These growth rates are applied to the 2012 base year estimates for each firm in the database.

Table 6-10 presents future year estimates of incrementally affected new and modified sources.

Table 6-10 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size

Firm Size Performing Well Completions	No. of Incrementally Affected Sources, 2020			No. of Incrementally Affected Sources, 2025		
	Hydraulically Fractured or Re-fractured Oil Wells	Gas Well Sites	Oil Well Sites	Hydraulically Fractured or Re-fractured Oil Wells	Gas Well Sites	Oil Well Sites
Small	3,500	5,600	33,000	3,800	11,000	68,000
Not Small	10,000	11,000	44,000	11,000	24,000	86,000
Total	**14,000**	**17,000**	**77,000**	**15,000**	**35,000**	**160,000**

Note: Sums may not total due to independent rounding. Assumes well sites have two wells apiece.

This approach assumes that no other firms perform potentially affected activities and firms performing these activities in 2012 will continue to do so in 2020 and 2025. Again, the analysis in this FRFA is meant to be illustrative of impacts on small entities. Exact predictions of future activities at the firm level is not possible.

Once the future year activities were estimated we allocated compliance costs across small entities based upon the costs estimated in the TSD and consistently with other analyses in this RIA. These cost estimates include estimates of revenue from natural gas recovery at the assumed value of $4/Mcf in 2012 dollars, again consistent with other analyses in this RIA. For hydraulically fractured and re-fractured oil well completions, we assumed each small entity is required to perform RECs and combustion in the same proportions assumed in the TSD and RIA. We also assumed the same proportion would be exploratory or delineation wells as the TSD and RIA. Table 6-11 shows the distribution of compliance costs estimates across firm size and year.

Table 6-11 Distribution of Estimated Compliance Costs[1] across Firm Size Classes

Firm Size	No. of Firms	Annualized Compliance Costs (2012$) 2020	2025
Small	2,069	110,000,000	190,000,000
Not Small	150	200,000,000	320,000,000
Total	**2,219**	**310,000,000**	**510,000,000**

[1] Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. As described in Section 6.1.3, these provisions account for the large majority of the rule's potential impact in 2020 and 2025.
Note: sums may not total due to independent rounding.

In order to estimate the cost-to-sales ratio, we again combined information from Hoovers and the DrillingInfo databases. The Hoovers database has sales information for some, but not all, small entities estimated in this FRFA analysis to have impacts. To supplement the sales information, we estimated 2012 sales by multiplying 2012 oil and natural gas production levels reported in the DrillingInfo database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the same $4/Mcf for natural gas.[83] For oil prices, we estimated revenues using two alternative prices, $70/bbl and $50/bbl. In the results, we call the case using $70/bbl the "primary scenario" and the case using the $50/bbl as the "low oil price scenario".[84] In the instances where the 2012 production-derived revenues exceeded the Hoovers revenues, we replaced the Hoovers estimate with the production-derived estimate as more likely to be an accurate estimate of sales for 2012.

6.3.5.2 Compliance Cost Impact Estimate Results

This section presents results of the cost-to-sales ratio analysis for both the primary scenario and the low oil price scenario. The percent of small entities with cost-to-sales ratios exceeding 1 percent and 3 percent in 2020 and 2025 are greater under the low oil price scenario, as would be expected due to lower estimated sales revenues from a lower oil price. Also, as expected, the entities with cost-to-sales ratios greater than 1 percent and greater than 3 percent increase from 2020 to 2025 in both the main case and the low oil price scenario as affected sources accumulate under the NSPS.

[83] The U.S. Energy Information Administration's 2015 Annual Energy Outlook projects 2020 Henry Hub natural gas prices to be $4.88/MMBtu in its reference case and $4.30/MMBtu in its "low oil" price case in 2013 dollars. Available at: <http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>. After adjusting to $/Mcf (using the conversion of 1 MMBtu = 1.208 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $4.80/Mcf in the reference case and $4.323/Mcf in the low oil price case. Rounding down to $4/Mcf likely under-estimates sales.

[84] The 2015 Annual Energy Outlook projects wellhead oil prices to be $75.16/bbl in its reference case and $54.10/bbl in its "low oil" price case in 2013 dollars. Available at: <http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>. After adjusting to 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $74.00/bbl in the reference case and $53.27/bbl in the low oil price case.

Table 6-12 Compliance Costs-to-Sales[1] Ratios across Firm Size Classes for Primary Scenario and Low Oil Price Scenario[2]

	2020 (Main Case)		2020 (Low Oil Price Case)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	2,031	-	2,043	-
Greater than 1 percent	564	28%	648	32%
Greater than 3 percent	289	14%	344	17%

	2025 (Main Case)		2025 (Low Oil Price Case)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	2,031	-	2,043	-
Greater than 1 percent	824	41%	924	45%
Greater than 3 percent	419	21%	502	25%

[1] Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. These provisions account for the large majority of the rule's potential impact in 2020 and 2025.

[2] In the main case, the wellhead prices are assumed to be $4/Mcf for natural gas and $70/bbl for crude oil. In the low oil price case, the wellhead prices are assumed to be $4/Mcf for natural gas and $50/bbl for crude oil.

6.3.5.3 Caveats and Limitations

The analysis above is subject to a number of caveats and limitations, many of which we discussed in the presentation of methods and results. It is useful, however, to present a complete list of the caveats and limitations here.

- Because of data limitations, the analysis presented in the FRFA only examines impacts on requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While impacts from these requirements constitute a large proportion of the estimated impacts from the final NSPS, the omission of the estimated costs of other requirements leads to a relative under-estimation of the impacts on small entities. Also, the impacts from other requirements may affect firms that are not drilling wells, such as pipeline transmission firms.
- Not all owner/operators listed in the DrillingInfo database could be identified in the Hoovers database. These owner/operators tend to have developed relatively few new or modified wells in 2012. As a result, we assumed these were small entities, whereas these entities may actually be subsidiaries of larger enterprises. While the impacts estimates are not affected in the aggregate by this assumption, the assumption likely leads to an over-estimate of the impact on small entities for the provisions examined.
- The analysis assumes the same population of entities completing wells in 2012 are also completing wells in 2020 and 2025, according to growth rates developed for the entire

sector. In the future, many of these firms will complete fewer or more wells, and other firms will complete wells. All of these firms combined may complete new or modified wells at higher or lower rates depending on economics and technological factors that are largely unpredictable.

- The approach used to estimate sales for the cost-to-sales ratio might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced in 2020 and 2025.

6.3.6 Regulatory Flexibility Alternatives

The EPA considered three major options for this final rule. The option EPA is finalizing contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. This option requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Additionally this option requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

The other options considered differ from the finalized option with respect to the requirements for fugitive emissions. One option exempted low production well sites from the well site fugitive requirements. This less stringent option was analyzed as an alternative to reduce burden on small entities. However, it was rejected because we believe that low production well sites have the same type of equipment and components as production well sites with production greater than 15 boe per day. Since we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. Additionally, we did not receive data showing that low production well sites have lower methane or VOC emissions than well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with industry stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable, and low production well sites were included in the selected option.

Lastly, the more stringent option required quarterly monitoring for all sites under the fugitive emissions program. This option lead to greater emission reductions, however it was not selected because it increased costs, resulting in a net effect of lower net benefits compared to the finalized option.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available on the World Wide Web approximately 60 days after promulgation of the rule, at https://www3.epa.gov/airquality/oilandgas/implement.html.

The EPA notes that the IRFA includes numerous recommendations made by the SBAR Panel[85]. The EPA considered these recommendations during the development of the proposal and final rule. The rationale for the EPA's acceptance or rejection of each recommendation can be found in the relevant discussion of each emission source throughout the preamble to the proposal, final rule, and RTC. Though all comments were seriously considered, the EPA is unable to incorporate all suggestions without compromising the effectiveness of the final regulation. Changes to the rule from proposal that may benefit small entities due to comments received include allowing both OGI and Method 21 as acceptable monitoring technology, replacing a performance based monitoring schedule with a fixed frequency, lengthening the time of initial fugitive monitoring from within 30 days to the later of either [**insert date 1 year after publication of the final rule in the Federal Register**] or with 60 days of the startup of production, and simplified the third party verification of technical infeasibility requirements. Though these are not monetized, we believe the flexibility and simplifications these changes have added to the rule result in a reduced burden on small entities.

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[85] The final SBAR Panel report is found at <https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4959>.

6.4 Employment Impact Analysis

In addition to addressing the costs and benefits of the final rule, the EPA has analyzed the impacts of this rulemaking on employment, which are presented in this section.[86] While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." [87] A discussion of compliance costs, including reporting and recordkeeping requirements, is included in Section 3 of this RIA. This analysis uses detailed engineering information on labor requirements for each of the control strategies identified in this final rule in order to estimate <u>partial</u> employment impacts for affected entities in the oil and gas industry. These bottom-up, engineering-based estimates represent only one portion of potential employment impacts within the regulated industry, and do not represent estimates of the *net* employment impacts of this rule. First, this section presents an overview of the various ways that environmental regulation can affect employment. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is valid and informative. The section concludes with partial employment impact estimates that rely on engineering-based information for labor requirements for each of the control strategies identified by the rule.

6.4.1 Employment Impacts of Environmental Regulation

From an economic perspective labor is an input into producing goods and services; if a regulation requires that more labor be used to produce a given amount of output, that additional labor is reflected in an increase in the cost of production. Moreover, when the economy is at full employment, we would not expect an environmental regulation to have a net impact on overall employment because labor is being shifted from one sector to another. On the other hand, in

[86] The employment analysis in this RIA is part of the EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

[87] Executive Order 13563 (January 21, 2011). *Improving Regulation and Regulatory Review. Section 1. General Principles of Regulation*, Federal Register, Vol. 76, Nr. 14, p. 3821.

periods of high unemployment, net employment effects (both positive and negative) are possible.

For example, an increase in labor demand due to regulation may result in a short-term net increase in overall employment as workers are hired by the regulated sector to help meet new requirements (e.g., to install new equipment) or by the environmental protection sector to produce new abatement capital resulting in hiring previously unemployed workers. When significant numbers of workers are unemployed, the opportunity costs associated with displacing jobs in other sectors are likely to be higher. And, in general, if a regulation imposes high costs and does not increase the demand for labor, it may lead to a decrease in employment. The responsiveness of industry labor demand depends on how these forces all interact. Economic theory indicates that the responsiveness of industry labor demand depends on a number of factors: price elasticity of demand for the product, substitutability of other factors of production, elasticity of supply of other factors of production, and labor's share of total production costs. Berman and Bui (2001) put this theory in the context of environmental regulation, and suggest that, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all.

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing environmental regulations. When a regulation is promulgated, one typical response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. On the other hand, the closure of plants that choose not to comply – and any changes in production levels at plants choosing to comply and remain in operation - occur after the compliance date, or earlier in anticipation of the compliance obligation. Environmental regulation may increase revenue and employment in the environmental technology industry. While these increases represent gains for that industry, they translate into costs to the regulated industries required to install the equipment.

Environmental regulations support employment in many basic industries. Regulated firms either hire workers to design and build pollution controls directly or purchase pollution control devices from a third party for installation. Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment—much like they hire workers to produce more output. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment.

Berman and Bui (2001) demonstrate using standard neoclassical microeconomics that environmental regulations have an ambiguous effect on employment in the regulated sector. The theoretical results imply that the effect of environmental regulation on employment in the regulated sector is an empirical question. Berman and Bui (2001) developed an innovative approach to examine how an increase in local air quality regulation that reduces nitrogen oxides (NO_X) emissions affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which incorporates Los Angeles and its suburbs. During the time frame of their study, 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in the regulated industries.[88] The authors find that "while regulations do impose large costs, they have a limited effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).[89]

While there is an extensive empirical, peer-reviewed literature analyzing the effect of environmental regulations on various economic outcomes including productivity, investment, competitiveness as well as environmental performance, there are only a few papers that examine the impact of environmental regulation on employment, but this area of the literature has been growing. As stated previously in this RIA section, empirical results from Berman and Bui (2001) suggest that new or more stringent environmental regulations do not have a substantial impact on net employment (either negative or positive) in the regulated sector. Similarly, Ferris, Shadbegian, and Wolverton (2014) also find that regulation-induced net employment impacts are

[88] Berman and Bui include over 40 4-digit SIC industries in their sample.
[89] Including the employment effect of exiting plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.

close to zero in the regulated sector. Furthermore, Gray et al (2014) find that pulp mills that had to comply with both the air and water regulations in the EPA's 1998 "Cluster Rule" experienced relatively small and not always statistically significant, decreases in employment. Nevertheless, other empirical research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). However, the methodology used in these two studies cannot estimate whether aggregate employment is lower or higher due to more stringent environmental regulation, it can only imply that relative employment growth in some sectors differs between more and less regulated areas. List *et al.* (2003) find some evidence that this type of geographic relocation, from more regulated areas to less regulated areas may be occurring. Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

While the theoretical framework laid out by Berman and Bui (2001) still holds for the industries affected under these emission guidelines, important differences in the markets and regulatory settings analyzed in their study and the setting presented here lead us to conclude that it is inappropriate to utilize their quantitative estimates to estimate the net employment impacts from this final regulation. In particular, the industries used in these two studies as well as the timeframe (late 1970's to early 1990's) are quite different than those in this final NSPS. Furthermore, the control strategies analyzed for this RIA include implementing RECs, reducing fugitive emissions, and reducing emissions from pneumatic controllers, pumps, and reciprocating and centrifugal compressors, which are very different than the control strategies examined by Berman and Bui.[90] For these reasons we conclude there are too many uncertainties as to the transferability of the quantitative estimates from Berman and Bui to apply their estimates to quantify the net employment impacts within the regulated sectors for this regulation, though these studies have usefulness for qualitative assessment of employment impacts.

The preceding sections have outlined the challenges associated with estimating net employment effects in the regulated sector and in the environmental protection sector. These challenges make it very difficult to accurately produce net employment estimates for the whole

[90] More detail on how emission reductions expected from compliance with this rule can be found in Section 3 of this RIA.

economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Given the difficulty with estimating national impacts of regulations, the EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the evaluation of costs, benefits, and economic impacts associated with environmental regulation, the EPA has formed a panel of experts as part of the EPA's Science Advisory Board (SAB) to advise the EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.[91] Once the EPA receives guidance from this panel it will carefully consider this input and then decide if and how to proceed on economy-wide modeling of net employment impacts of its regulations.

6.4.2 Labor Estimates Associated with Final Requirements

Section 2 of the RIA, in Table 2-17 and Table 2-18, presents background information on employment and wages in the oil and natural gas industry. As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in six oil and natural gas-related NAICS codes from 1990 to 2014.[92] The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry. From 1990 to 2014, average wages for the oil and natural gas industry increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry.

The focus of this part of the analysis is on labor requirements related to the compliance actions for the final rule of the affected entities within the oil and natural gas sector. We do not estimate any potential changes in labor outside of the affected sector, and due to data and

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[91] For further information see: http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument

[92] NAICS 211111, 21112, 213111, 213112, 486110, and 486210.

methodology limitations we do not estimate net employment impacts for the affected sector, apart from the partial estimate of the labor requirements related to control strategies. This analysis estimates the labor required to the install, operate, and maintain control equipment and activities, as well as to perform new reporting and recordkeeping requirements.

It is important to highlight that, unlike the typical case where a firm often has to reduce production in order to reduce output of negative production externalities (i.e., emissions), many of the emission controls required by the final NSPS will simultaneously increase production and reduce negative externalities. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. Therefore, new labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions. However, these rules may require unprofitable investments for some operators, and there is a possibility that these producers decrease output in response and create downward pressure on labor demand, both in the regulated sector and on those sectors using natural gas as an input. This RIA does not include quantified estimates of these potential adverse effects on the labor market due to data limitations and theoretical challenges, as described above.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because the EPA does not currently have this information. The labor requirements analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in Chapter 3 of this RIA includes estimates of the labor requirements associated with implementing the regulations. Each of these labor changes may be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of employees involved or whether new jobs are created for new employees.

The results of this employment analysis of the NSPS are presented in Table 6-13 through

Table 6-16 for 2020 and 2025 for individual sources regulated under this rule. Table 6-17 presents summary-level labor impacts for all sources. The tables break down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. The labor information is based upon the cost analysis presented in the TSD that supports this rule, based upon analysis presented in the RIA developed for the 2012 NSPS and NESHAP Amendments for the Oil and Natural Gas Sector (U.S. EPA, 2012). In addition, for the final NSPS, reporting and recordkeeping requirements were estimated for the entire rule rather than by anticipated control requirements. The reporting and recordkeeping estimates are consistent with estimates the EPA submitted as part of its Information Collection Request (ICR), the estimated costs which are included in the cost estimates presented in Chapter 3.

Table 6-13 presents estimates of labor requirements for hydraulically fractured oil well completions. The REC and completion combustion requirements are associated with certain new and existing oil well completions. While individual well completions take place over a short period of time (days to a few weeks), the overall industry completes new wells and re-completes some existing wells every year. Because of the continuing nature of new and existing well completions, annually, at the industry level, we report the REC-related labor requirements in annual units.

The per-unit estimates of one-time labor requirements associated with implementing RECs and completion combustion are drawn from the labor requirements estimated for implementing RECs on hydraulically fractured well completions in EPA (2012). However, the labor requirements in that report were based upon a completion that is assumed to last seven days (218 hours per completion for a REC or 22 hours labor per completion for completion combustion). In this analysis, completion events for hydraulically fractured oil wells are assumed to last three days, so we multiply the seven-day requirements by 3/7 (93 hours per completion for a REC or 9 hours labor per completion for completion combustion).

Table 6-13 Estimates of Labor Required to Comply with NSPS for Hydraulically Fractured Oil Well Completions, 2020 and 2025

Emissions Source/Control	Projected No. of Incrementally Affected Units (2020)	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time FTE	Annual FTE
				2020			
Hydraulically Fractured Oil Well Completions and Recompletions							
Completions where REC and completion combustion is required	7,500	0	93	0	700,000	0	340
Completions where completion combustion is required	5,600	0	9	0	53,000	0	25
Total	**13,000**	**N/A**	**N/A**	**0**	**760,000**	**0**	**360**
				2025			
Hydraulically Fractured Oil Well Completions and Recompletions							
Completions where REC and completion combustion is required	8,000	0	93	0	750,000	0	360
Completions where completion combustion is required	6,000	0	9	0	57,000	0	27
Total	**14,000**	**N/A**	**N/A**	**0**	**800,000**	**0**	**390**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per-unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-14 presents estimates of labor requirements for fugitive emissions. Consistent with the cost estimates for fugitive emissions presented in Section 5 of the TSD, we estimate labor associated with company-level activities and activities at field sites. Company-level activities include one-time activities such as planning the company’s fugitive emissions program and annual requirements such as reporting and recordkeeping. Field-level activities include semiannual inspection and repair of leaks. It is important to note, however, that the compliance costs estimates for leak inspection were based upon an estimate of the costs to hire a contractor to provide the inspection service, but the source providing this information does not have a breakdown of the labor component of the rental cost. As a result, the labor requirements for the fugitives program remain uncertain.

Table 6-14 Estimates of Labor Required to Comply with NSPS for Fugitive Emissions, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incrementally Affected Units (2020)	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time FTE	Annual FTE
					2020			
Well Sites								
Company-level	Planning	4,300	120	0.0	500,000	0	240	0
Site-level	Monitoring and Maintenance	94,000	0.0	14	0	1,300,000	0	640
Gathering and Boosting Stations								
Company-level	Planning	480	120	0.0	57,000	0	27	0
Site-level	Monitoring and Maintenance	480	0.0	110	0	52,000	0	25
Transmission Compressor Stations								
Company-level	Planning	20	120	0.0	2,400	0	1	0
Site-level	Monitoring and Maintenance	20	0.0	110	0	2,100	0	1
Storage Compressor Stations								
Company-level	Planning	25	120	0.0	3,000	0	1	0
Site-level	Monitoring and Maintenance	25	0.0	210	0	5,300	0	3
Total		**94,000**	**N/A**	**N/A**	**560,000**	**1,400,000**	**270**	**660**
					2025			
Well Sites								
Company-level	Planning	4,300	120	0.0	500,000	0	240	0
Site-level	Monitoring and Maintenance	190,000	5.4	14	0	2,700,000	0	1,300
Gathering and Boosting Stations								
Company-level	Planning	480	120	0.0	57,000	0	27	0
Site-level	Monitoring and Maintenance	960	0.0	110	0	100,000	0	50
Transmission Compressor Stations								
Company-level	Planning	20	120	0.0	2,400	0	1	0
Site-level	Monitoring and Maintenance	40	0.0	110	0	4,300	0	2
Storage Compressor Stations								
Company-level	Planning	25	120	0.0	3,000	0	1	0
Site-level	Monitoring and Maintenance	50	0.0	210	0	11,000	0	5
Total		**190,000**	**N/A**	**N/A**	**560,000**	**2,800,000**	**270**	**1,400**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by theper unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Most labor required for fugitive emissions is needed at well sites in the field, which number in the thousands. Note that the labor requirements estimates increase from 2020 to 2025 as the number of sites regulated under the final NSPS accumulates.

Table 6-15 presents labor requirement estimates for monitoring and maintainence requirements for reciprocating compressors and routing emissions to a control device for centrifugal compressors. Like the estimates for completions, the per unit labor estimates were based on EPA (2012). As relatively little labor is required for reciprocating compressors and relatively few affected centrifugal compressors are expected in the future, the estimates of both one-time and on-going labor requirements for compressor requirements are minimal.

Table 6-15 Estimates of Labor Required to Comply with NSPS for Reciprocating and Centrifugal Compressors, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor Est. (hrs)	Per-unit Annual Labor Est. (hrs)	Total One-Time Labor Estimate (hrs)	Total Annual Labor Estimate (hrs)	One-time FTE	Annual FTE
					2020			
Compressors								
Reciprocating	Monitoring and Maintenance	160	1	1	160	160	0	0
Centrifugal	Route to Control	5	360	0	1,800	0	1	0
Total		**170**	**N/A**	**N/A**	**2,000**	**160**	**1**	**0**
					2025			
Compressors								
Reciprocating	Monitoring and Maintenance	320	1	1	160	320	0	0
Centrifugal	Route to Control	10	360	0	1,800	0	1	0
Total		**330**	**N/A**	**N/A**	**2,000**	**320**	**1**	**0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-16 presents the labor requirement estimates for requirements applying to pneumatic controllers and pneumatic pumps. Note that pneumatic controllers have no one-time or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation (U.S. EPA, 2012). In this instance, we assume the incremental labor requirements are zero. Meanwhile, we are currently unable to estimate the labor associated with pneumatic pump control activities.

Table 6-16 Estimates of Labor Required to Comply with NSPS for Pneumatic Controllers and Pumps, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor Est. (hrs)	Per-unit Annual Labor Est. (hrs)	Total One-Time Labor Estimate (hrs)	Total Annual Labor Estimate (hrs)	One-time FTE	Annual FTE
				2020				
Pneumatic Controllers	Emissions Limit	480	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	3,900	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
				2025				
Pneumatic Controllers	Emissions Limit	960	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	7,900	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-17 presents the labor estimates across all emissions sources. Two main categories contain the majority of the labor requirements for the final NSPS: implementing reduced emissions completions (REC) at hydraulically fracture oil well completions and fugitive emissions detection and repair at well sites. The up-front labor requirement to comply with the final NSPS is estimated at 270 FTEs in 2020 and in 2025. The annual labor requirement to comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 6-17 Estimates of Labor Required to Comply with NSPS, 2020 and 2025

Emissions Source	Projected No. of Incrementally Affected Units (2020)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time FTE	Annual FTE
			2020		
Hydraulically Fractured and Re-fractured Oil Well Completions	13,000	0	760,000	0	360
Fugitive Emissions	94,000	560,000	1,400,000	270	660
Pneumatic Controllers	480	0	0	0	0
Pneumatic Pumps	3,900	N/A	N/A	N/A	N/A
Reciprocating Compressors	160	160	160	0	0
Centrifugal Compressors	5	1,800	0	1	0
Reporting and Recordkeeping Requirements	All	0	180,000	0	88
Total	**110,000**	**570,000**	**2,300,000**	**270**	**1,100**
			2025		
Hydraulically Fractured and Re-fractured Oil Well Completions	14,000	0	800,000	0	390
Fugitive Emissions	190,000	560,000	2,800,000	270	1,400
Pneumatic Controllers	960	0	0	0	0
Pneumatic Pumps	7,900	N/A	N/A	N/A	N/A
Reciprocating Compressors	320	160	320	0	0
Centrifugal Compressors	10	1,800	0	1	0
Reporting and Recordkeeping Requirements	All	0	180,000	0	88
Total	**220,000**	**570,000**	**3,800,000**	**270**	**1,800**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Rounded to two significant digits. Totals may not sum due to independent rounding.

6.5 References

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