Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

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Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

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1 EXECUTIVE SUMMARY

1.1 Background

The action analyzed in this regulatory impact analysis (RIA) proposes to amend 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 proposal because methane is a greenhouse gas (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.

The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are proposing both methane and VOC standards for several emission sources not currently covered by the NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, pneumatic pumps). In addition, we are proposing methane standards for certain emission sources that are currently regulated for VOC (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 currently regulated VOC sources.

With respect to certain equipment that are used across the source category, the current NSPS regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The proposed amendents would establish methane standards for these equipment across the source category and extend the current VOC standards to the remaining unregulated equipment. Lastly, amendments to the current NSPS are being proposed that improve several aspects of the current 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 August 16, 2012, final 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 current 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 proposed 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 proposed NSPS.[1] We also estimate potential impacts of the proposed rule on the national energy economy 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 and 2025, which spans a period of six years. The analysis of 2020 is assumed to represent the first year the full suite of proposed standards is in effect and thus represents a single year of potential impacts. We estimate impacts in 2025 to illustrate how new and modified sources accumulate over time under the proposed NSPS. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2020 to 2024 that are also 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 results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

[1] The analysis in this draft RIA constitutes 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.

The baseline used for the impacts analysis of our NSPS takes into account emissions reductions conducted pursuant to state regulations covering the relevant operations. More 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 opportunity cost of production 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 that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the goods produced, processed, transported, or stored are crude oil, natural gas, and other hydrocarbon products. These social costs associated with the climate, health, and welfare impacts are referred to as negative externalities. If an oil and natural gas firm pollutes the atmosphere while extracting, processing, transporting, or storing the commodities, this cost will be borne not by the polluting firm but by society as a whole. The market price of the products will fail to incorporate the full opportunity cost to society of producing the products. All else equal, given this externality, the quantity of oil and natural gas produced in a free market will not be at the socially optimal level. More oil and natural gas will be produced than would occur if the power producers had to account for the full opportunity 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.[2] Table 1-1 shows the emissions

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[2] See Chapter 3 for a detailed discussion of the comparative impacts of the regulatory options. The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions (RECs) in combination with combustion. This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately $70 million per year lower cost.

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 proposal. Option 1 was selected for co-proposal.

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

Emissions Point	Emissions Control	Option 1	Option 2 (proposed)	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 Pads	Monitoring and Maintenance	**Annual**	**Semiannual**	**Quarterly**
Gathering and Boosting Stations	Monitoring and Maintenance	**Semiannual**	**Semiannual**	**Quarterly**
Transmission Compressor Stations	Monitoring and Maintenance	**Semiannual**	**Semiannual**	**Quarterly**
Pneumatic Pumps				
Well Pads	Route to control	**X**	**X**	**X**
Gathering and Boosting Stations	Route to control	**X**	**X**	**X**
Transmission and Storage Compressor Stations	Route to control	**X**	**X**	**X**
Pneumatic Controllers -				
Natural Gas Transmission and Storage Stations	Emissions limit	**X**	**X**	**X**
Reciprocating Compressors				
Natural Gas Transmission and Storage Stations	Annual Monitoring and Maintenance	**X**	**X**	**X**
Centrifugal Compressors				
Natural Gas Transmission and Storage Stations	Route to control	**X**	**X**	**X**

The proposed 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 also requires fugitive emissions survey and repair programs be

However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

performed semiannually (twice per year) at newly drilled or refractured oil and natural gas well sites, new or modified gathering and boosting stations, and new or modified transmission and storage compressor stations. However, low production well sites are exempt from the well site fugitive requirements. A low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.[3] Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this RIA presents a “low” impact case and “high” impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate low production sites, assuming that the fraction of wells meeting the low production criteria in the future will be the same as in 2012 (based on the first month of production data from wells newly completed or modified in 2012).The high impact case includes all forecasted well sites providing a bounding case where no newly completed or modified wells meet the low production criteria. Summary results for option 2, then, are presented as ranges.

Options 1 and 3 differ from the Option 2 with respect to the requirements for fugitive emissions. Meanwhile, the co-proposed Option 1 requires annual monitoring for well sites, including low production sites, while maintaining semiannual requirements for others sites. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program, including low production sites. More frequent surveys result in higher costs, higher emissions reductions, and increased natural gas recovery over the co-proposed Option 2.

1.4 Summary of Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-2 through Table 1-4. Note all dollar estimates are in 2012 dollars:

- **Emissions Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOCs and 310

[3] Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

to 400 tons of hazardous air pollutants (HAP) in 2020, increasing to 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOCs, and 1,900 to 2,500 tons of HAP prevented in 2025.[4] The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 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).[5] The EPA estimates that, in 2020, the proposal will yield monetized climate benefits of $88 million to approximately $550 million; the mean SC-CH_4 at the 3% discount rate results in an estimate of about $200 to $210 million in 2020. In 2025, the EPA estimates monetized climate benefits of $220 million to approximately $1.4 billion; the mean SC-CH_4 at the 3% discount rate results in an estimate of about $460 to $550 million in 2025.[6] While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in 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.[7] This is not to imply that there are no health benefits anticipated from the proposed rule; 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 proposed NSPS are anticipated to have minor secondary disbenefits.

- **Engineering Cost Analysis:** The EPA estimates the total capital cost of the proposed NSPS to be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 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 proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated

[4] Estimates are presented in short tons.

[5] 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.

[6] The range of estimates reflects four SC-CH_4 estimates 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.

[7] 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 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.

engineering compliance costs of about $8 million in 2020 and $16 to $19 million in 2025, given the EPA estimates that about 8 million Mcf in 2020 and 16 to 19 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 proposed NSPS is $200 million in 2020 and $490 million in 2025, or $150 to $170 million in 2020 and $310 to $420 million in 2025, when estimated revenues from additional natural gas are included.[8]

- **Energy System Impacts Analysis:** The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system.[9] We estimate that natural gas and crude oil production levels remains essentially unchanged in 2020, while slight declines are estimated for 2025 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.
- **Small Entity Analyses:** To understand the potential impact of the proposed rule of 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 it is not able to certify that the proposed rule will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). As a result, the EPA initiated a Small Business Advisory Review panel and completed an Initial Regulatory Flexibility Analysis.
- **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. We 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 proposed NSPS is estimated at about 50 to 70 FTEs in 2020 and in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 470 to 530 FTEs in 2020 and 1,100 to 1,400 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of people

[8] The choice of discount rate has a small effect on nationwide annualized 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 proposal.

[9] The EPA only modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

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 co-proposed Option 1, Table 1-3 presents summary results for the co-proposed Option 2, and Table 1-4 presents summary results for Option 3. The summary results for Option 2 reflects the range from the low impacts to high impacts case with respect the well site fugitive emissions requirements.

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]	\$200 million	\$470 million
Total Costs[2]	\$150 million	\$310 million
Net Benefits[3]	\$43 million	\$160 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC reduced	Health effects of $PM_{2.5}$ and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 310 tons of HAP reduced	Health effects of HAP exposure from 1,900 tons of HAP reduced
	Health effects of ozone exposure from 170,000 tons of methane	Health effects of ozone exposure from 340,000 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 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 \$89 million to \$530 million in 2020 and \$220 million to \$1,200 million in 2025 for the proposed option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 million metric tons in 2020 and 7.7 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[3] Estimates may not sum due to independent rounding.

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

	2020	2025
Total Monetized Benefits[1]	$200 to $210 million	$460 to $550 million
Total Costs[2]	$150 to $170 million	$320 to $420 million
Net Benefits[3]	$35 to $42 million	$120 to $150 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC reduced	Health effects of $PM_{2.5}$ and ozone exposure from 170,000 to 180,000 tons of VOC reduced
	Health effects of HAP exposure from 310 to 400 tons of HAP reduced	Health effects of HAP exposure from 1,900 to 2,500 tons of HAP reduced
	Health effects of ozone exposure from 170,000 to 180,000 tons of methane	Health effects of ozone exposure from 340,000 to 400,000 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 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 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 $88 million to $550 million in 2020 and $250 million to $1,400 million in 2025 for the proposed option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[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]	$220 million	$640 million
Total Costs[2]	$210 million	$680 million
Net Benefits[3]	$7.6 million	-$35 million
Non-monetized Benefits	Non-monetized climate benefits Health effects of $PM_{2.5}$ and ozone exposure from 130,000 tons of VOC reduced	Non-monetized climate benefits Health effects of $PM_{2.5}$ and ozone exposure from 200,000 tons of VOC reduced
	Health effects of HAP exposure from 510 tons of HAP reduced	Health effects of HAP exposure from 3,200 tons of HAP reduced
	Health effects of ozone exposure from 190,000 tons of methane	Health effects of ozone exposure from 470,000 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 $99 million to $590 million in 2020 and $300 million to $1,700 million in 2025 for this more stringent option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 4.2 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[3] Estimates may not sum due to independent rounding.

1.5 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 statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small entity impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following 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 proposed NSPS.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2013, the Energy Information Administration (EIA) estimates that about 490,000 producing natural gas wells operated in the U.S. The latest available information from EIA indicates there were about 360,000 producing oil wells in the U.S. as of 2009. Domestic dry natural gas production was 24.3 trillion cubic feet (tcf) in 2013, the highest annual production level in U.S. history. The leading five natural gas producing states are Texas, Pennsylvania, Louisiana, Oklahoma, and Wyoming. Domestic crude oil production in 2013 was 2,716 million barrels (bbl), the highest annual level in the U.S. since 1991. The leading five crude oil producing states are 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 proposed 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 analysis 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 natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

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 classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per-unit 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 API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has 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 which 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 exists in a gaseous phase or in 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 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 streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. 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° 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 abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

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 is released down into the drill pipe then up the walls of the well bore, which removes 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 and 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 so that more oil or natural gas can 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 is a mix of sand and other materials that 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 natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. 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). Lacking enough pressure for the resource to 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 or 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

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and 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. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity 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 is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that 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 liquids 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 or solid desiccant, and 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. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. 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.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them 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 move natural gas at increased pressure in 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. According to EIA[10], these concepts are defined 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 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 liquefiable portion has been removed from the natural gas, as well as any non-hydrocarbon gases that render the natural gas unmarketable have been removed. 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 totally technically recoverable crude oil resources.

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[10] 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).

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 offshore areas. While the dry natural gas proved reserves in 2009 were estimated at 272.5 tcf, wet natural gas reserves were estimated at 283.9 tcf. Of the 283.9 tcf, 250.5 tcf (about 88 percent) is considered to be wet non-associated natural gas, while 33.3 tcf (about 12 percent) is considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas, according to EIA, is natural gas which occurs in crude oil reservoirs as free natural gas or in solution with crude oil.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2013. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. 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.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2013

	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	199,763	20,682	220,445	1,103,229	272,509	1,375,738
2010	201,764	23,267	225,031	1,124,545	304,625	1,429,170
2011	203,825	26,544	230,369	1,147,447	334,067	1,481,514
2012	206,202	30,529	236,731	1,171,480	308,036	1,479,516
2013	208,918	33,371	242,289	1,195,814	338,264	1,534,078

Source: U.S. Energy Information Administration

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 11 percent in the early 1990s to 8 to 10 percent over the period from 2006 to 2013 for crude oil and from above 11 percent during the 1990s to between 7 and 9 percent from 2006 to 2013 for natural gas.

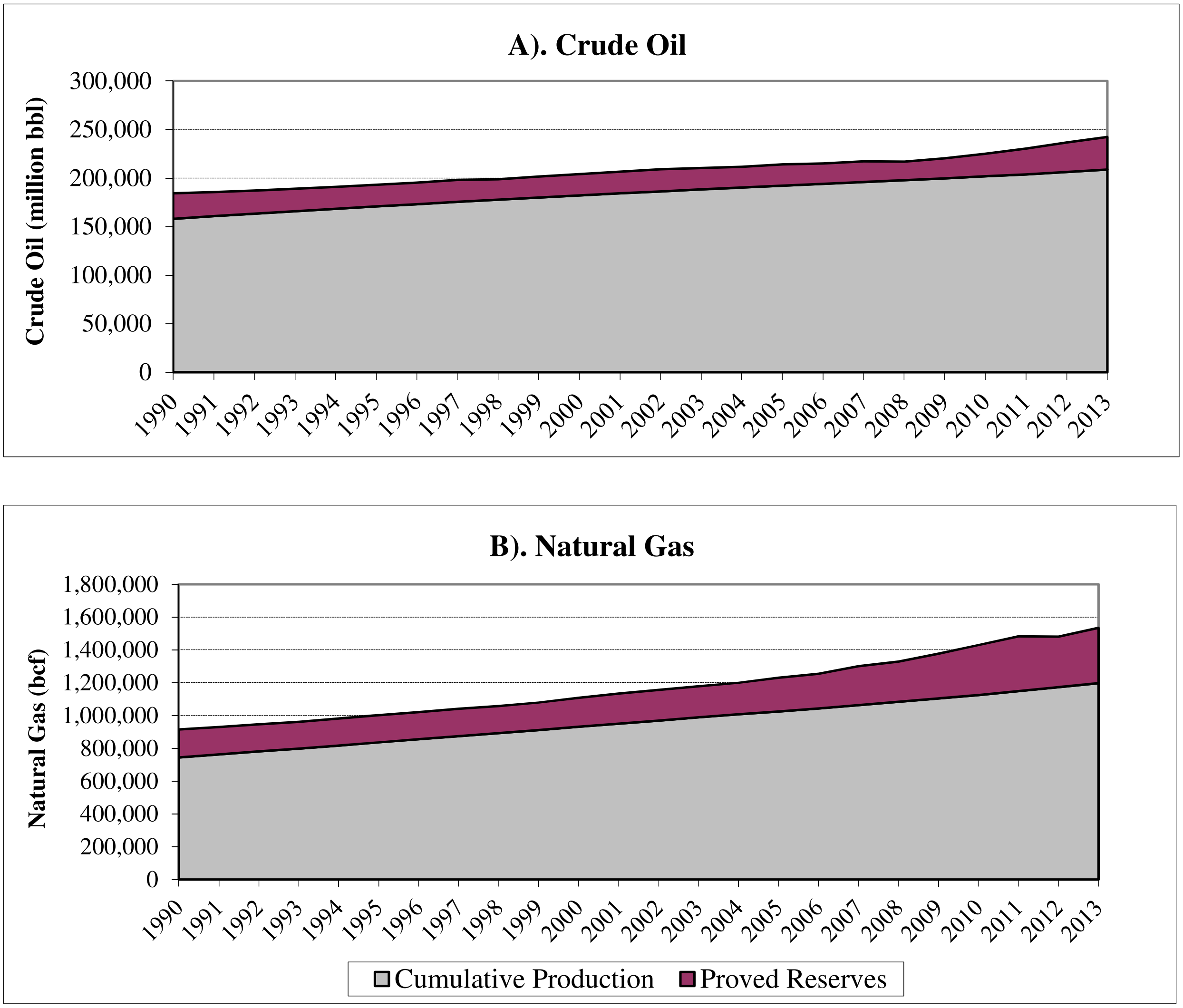

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2013. Five areas currently account for 81 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by North Dakota, U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Pennsylvania, Wyoming, Oklahoma, and West Virginia) account for about 65 percent of the U.S. total proved reserves of natural gas.

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	44	1,597	0.1	0.5
Alaska	2,898	7,316	8.7	2.2
Arkansas	40	13,518	0.1	4.0
California	2,876	1,887	8.6	0.6
Colorado	896	22,381	2.7	6.6
Florida	38	15	0.1	0.0
Kansas	372	3,592	1.1	1.1
Kentucky	17	1,663	0.1	0.5
Louisiana	503	20,164	1.5	6.0
Michigan	64	1,807	0.2	0.5
Miscellaneous States	105	2,552	0.3	0.8
Mississippi	223	595	0.7	0.2
Montana	413	575	1.2	0.2
New Mexico	1,171	13,576	3.5	4.0
New York	*	144	*	0.0
North Dakota	5,677	5,420	17.0	1.6
Ohio	42	3,161	0.1	0.9
Oklahoma	1,019	26,873	3.1	7.9
Pennsylvania	15	49,674	0.0	14.7
Texas	10,468	90,349	31.4	26.7
U.S. Federal Offshore	5,137	8,193	15.4	2.4
Utah	613	6,829	1.8	2.0
West Virginia	17	22,765	0.1	6.7
Wyoming	723	33,618	2.2	9.9
Total Proved Reserves	**33,371**	**338,264**	**100.0**	**100.0**

Source: U.S. Energy Information Administration. Total may not sum due to independent rounding.
* New York crude oil reserves are included in miscellaneous states.

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. Since 2008, domestic oil production has recovered to the highest levels since 1991. Table 2-4 shows U.S. production in 2013 at 2,716 million bbl per year.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price, 1990-2013

	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	31.55
1991	2,707	614	4,409	16.54	25.21
1992	2,625	594	4,419	15.99	23.83
1993	2,499	584	4,279	14.25	20.74
1994	2,431	582	4,178	13.19	18.80
1995	2,394	574	4,171	14.62	20.41
1996	2,366	574	4,122	18.46	25.31
1997	2,355	573	4,110	17.23	23.23
1998	2,282	562	4,060	10.87	14.50
1999	2,147	546	3,932	15.56	20.44
2000	2,131	534	3,990	26.72	34.32
2001	2,118	530	3,995	21.84	27.42
2002	2,097	529	3,963	22.51	27.84
2003	2,062	513	4,019	27.56	33.42
2004	1,991	510	3,905	36.77	43.39
2005	1,891	498	3,798	50.28	57.49
2006	1,857	497	3,737	59.69	66.21
2007	1,853	500	3,706	66.52	71.87
2008	1,830	526	3,479	94.04	99.64
2009	1,953	526	3,712	56.35	59.26
2010	2,001	520	3,848	74.71	77.62
2011	2,060	536	3,844	95.73	97.45
2012	2,378	N/A	N/A	94.52	94.52
2013	2,716	N/A	N/A	95.99	94.58

Source: U.S. Energy Information Administration
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.

Average well productivity has also generally decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend.

Annual production of natural gas from natural gas wells has increased more than 8000 bcf from the 1990 to 2013 (Table 2-5). The number of wells producing natural gas has nearly doubled between 1990 and 2011 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2013

	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	30,005	24,334	487,286	49.9

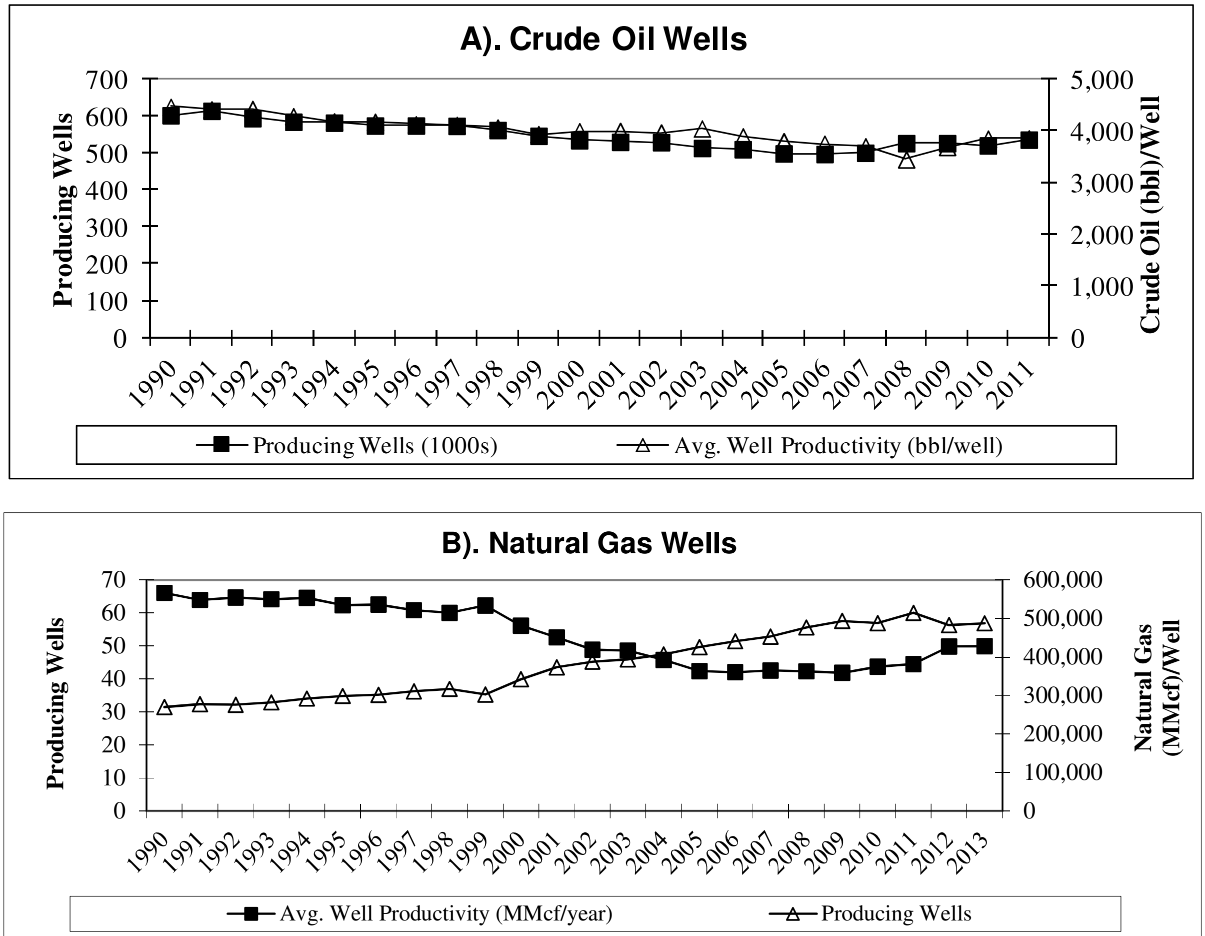

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2013.

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 this 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, well average depth has also increased by 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).

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.

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 rates of water production compared to more Midwestern states such as Illinois, Missouri, Indiana, and Kansas. Figure 2-3 shows the distribution of produced water management practices in 2007.

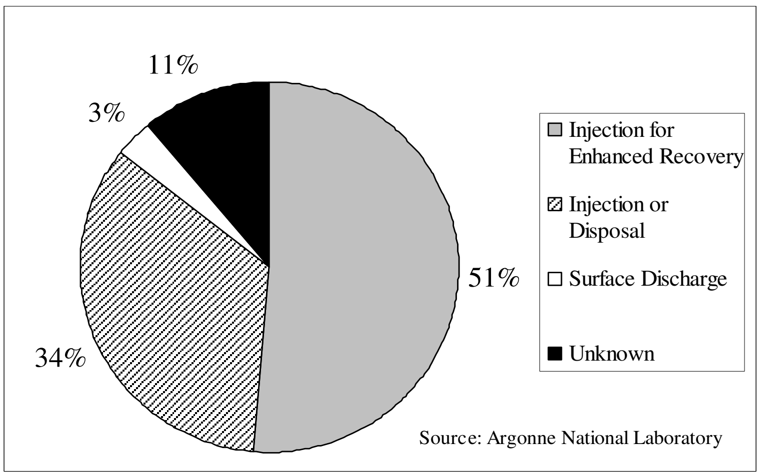

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

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. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets 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).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2011 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 2010-2013

	Natural Gas Pipelines (miles)				
	Distribution mains	Distribution Service	Transmission pipelines	Gathering lines	Total
2010	1,229,501	872,377	304,775	19,640	2,426,293
2011	1,238,683	881,886	305,036	19,364	2,444,969
2012	1,247,115	892,209	303,333	16,524	2,459,181
2013	1,254,686	894,605	302,827	17,435	2,469,553

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 December 29, 2014.

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 to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers.

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 consumption dropped 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 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

		Percent of Total			
	Total (million barrels)	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.

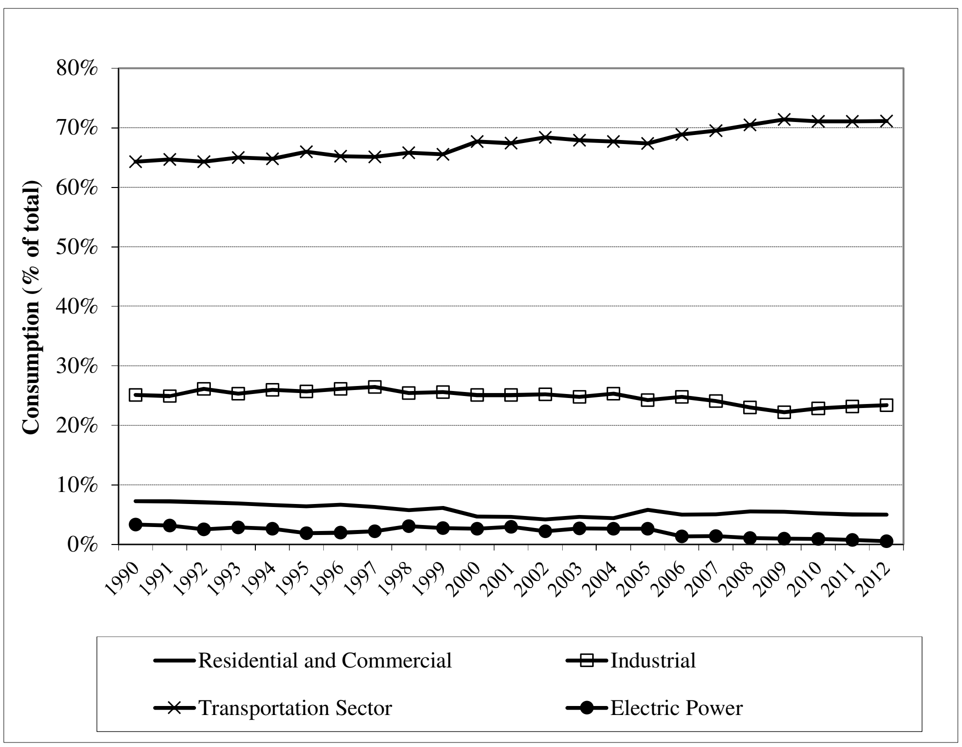

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2011

Natural gas consumption has increased over the last twenty years. From 1990 to 2012, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite 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, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2012

		Percent of Total				
	Total (tcf)	**Residential**	**Commercial**	**Industrial**	**Electric Power**	**Transportation**
1990	19.93	22.0	13.1	45.3	16.2	3.3
1991	19.56	23.2	13.9	42.8	17.0	3.1
1992	20.23	23.1	13.8	43.1	17.0	2.9
1993	20.80	23.8	13.8	42.7	16.7	3.0
1994	21.27	22.8	13.6	42.0	18.3	3.2
1995	22.25	21.8	13.6	42.4	19.0	3.2
1996	22.67	23.1	14.0	42.9	16.8	3.2
1997	22.88	21.8	14.1	43.0	17.8	3.3
1998	22.32	20.3	13.4	42.9	20.6	2.9
1999	22.43	21.1	13.6	40.9	21.5	2.9
2000	23.31	21.3	13.6	39.9	22.3	2.8
2001	22.21	21.4	13.6	37.9	24.1	2.9
2002	23.02	21.2	13.7	37.5	24.7	3.0
2003	22.03	23.0	14.4	37.5	22.2	2.8
2004	21.99	22.1	14.2	37.9	23.0	2.7
2005	21.62	22.3	13.9	35.7	25.3	2.9
2006	21.37	20.4	13.2	35.9	27.6	2.9
2007	22.78	20.7	13.2	34.6	28.6	2.9
2008	22.95	21.3	13.7	34.4	27.6	3.0
2009	22.89	20.9	13.6	32.5	29.9	3.1
2010	24.06	19.9	12.9	33.7	30.6	3.0
2011	24.38	19.3	12.9	33.7	31.0	3.0
2012	25.64	16.3	11.3	33.4	36.1	3.0

Source: U.S. Energy Information Administration.

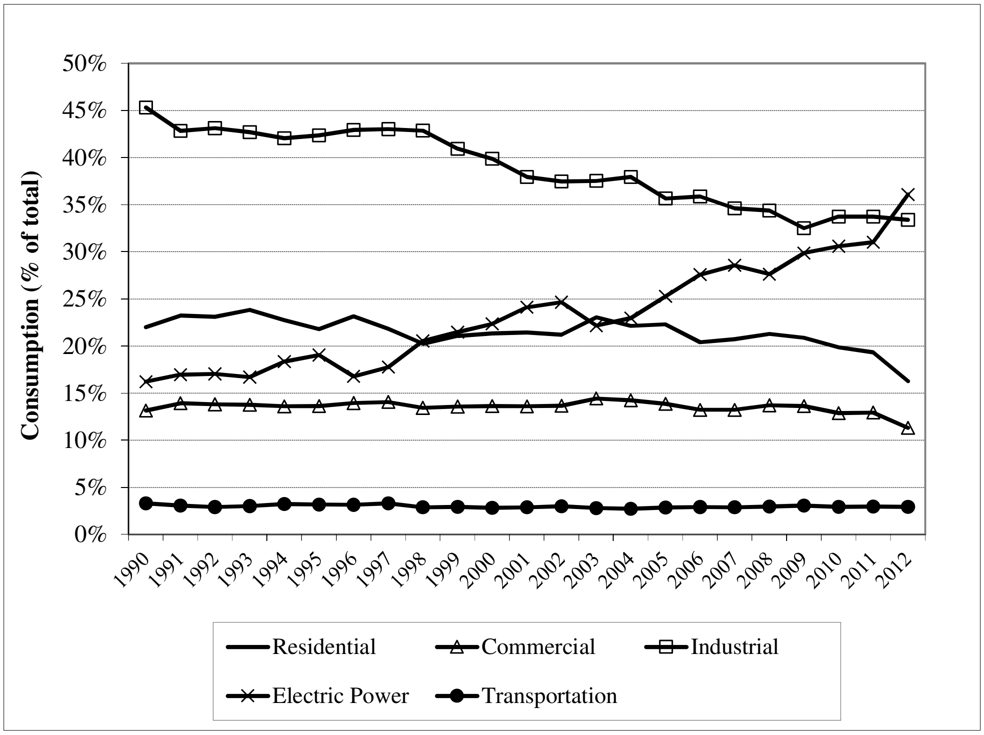

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2012

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), 1990-2013

	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

Source: U.S. Energy Information Administration.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 through 2012 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. Until recent years, industry analysts forecast 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, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2013

	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.3
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	N/A

Source: U.S. Energy Information Administration.

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 2014 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 7, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2014 Annual Energy Outlook.

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.

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.**

Meanwhile, show increases for natural gas drilling in the lower 48 states from the present to 2040, more than doubling during this 25-year period.

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and 6 depicts these trends graphically.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2011-2040

	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 (2012 dollars per barrel)
2011	2,065	1,336	520	209	97	3,244	7,472	9,161	98.12
2012	2,370	1,679	498	193	32	3,078	7,850	9,018	94.94
2013	2,819	2,132	500	186	85	2,687	8,409	9,360	97.54
2014	3,113	2,396	544	173	59	2,355	8,640	10,054	98.50
2015	3,299	2,534	595	169	0	2,250	8,848	10,224	93.15
2016	3,483	2,581	733	169	0	2,105	9,071	10,957	89.76
2017	3,488	2,598	719	172	0	2,122	9,099	11,073	88.23
2018	3,495	2,607	716	172	0	2,120	9,110	11,228	88.87
2019	3,507	2,620	721	166	0	2,102	9,116	11,410	90.82
2020	3,487	2,632	695	160	0	2,112	9,086	11,599	92.93
2021	3,437	2,632	654	151	0	2,149	9,024	11,652	95.30
2022	3,390	2,624	625	142	0	2,169	8,950	11,721	97.81
2023	3,355	2,610	611	134	0	2,181	8,890	11,830	100.25
2024	3,312	2,594	591	126	0	2,203	8,826	11,898	102.65
2025	3,287	2,570	598	119	0	2,209	8,782	12,050	104.90
2026	3,224	2,517	595	112	0	2,259	8,707	12,192	106.89
2027	3,164	2,474	586	105	0	2,312	8,640	12,237	109.28
2028	3,108	2,429	581	99	0	2,356	8,573	12,299	111.00
2029	3,059	2,381	585	93	0	2,397	8,515	12,367	113.00
2030	3,031	2,330	614	88	0	2,422	8,484	12,564	114.69
2031	2,978	2,284	611	83	0	2,475	8,431	12,585	116.70
2032	2,947	2,237	610	100	0	2,505	8,398	12,612	118.92
2033	2,936	2,195	617	124	0	2,518	8,390	12,650	121.24
2034	2,914	2,155	618	142	0	2,554	8,383	12,642	123.50
2035	2,873	2,114	622	138	0	2,610	8,356	12,622	125.59
2036	2,830	2,068	628	135	0	2,666	8,327	12,618	127.47
2037	2,810	2,028	651	131	0	2,703	8,324	12,687	129.33
2038	2,759	1,987	654	117	0	2,781	8,299	12,656	131.59
2039	2,749	1,949	694	105	0	2,797	8,294	12,859	134.45
2040	2,730	1,909	726	95	0	2,826	8,287	12,938	137.63

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

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2040, an increase of 25 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 12 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing more than 100 percent from 2010 to 2040, from $76.78 per barrel to $160.38 per barrel in 2011 dollar terms.

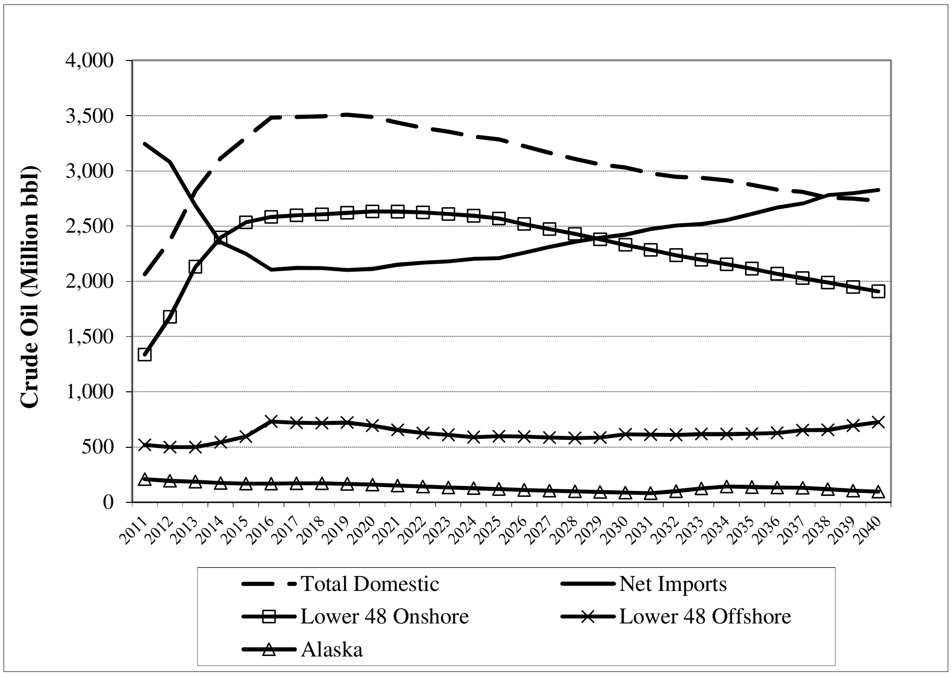

Figure 2-6 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040

Table 2-15 shows domestic natural gas production is forecast to increase until 2040. Meanwhile, imports of natural gas via pipeline are expected to be eliminated during the forecast period, from 1.68 tcf in 2011 to -2.43 in 2040 tcf. Imports of LNG are also eliminated during the forecast period, from 0.28 tcf in 2011 to -3.37 tcf in 2040. Total supply, then, increases about 33 percent, from 22.55 tcf in 2011 to 37.54 tcf in 2040.

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

	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 (2012 dollars per million Btu)
2011	22.55	0.06	1.68	0.28	24.57	324.6	4.07
2012	24.06	0.06	1.37	0.15	25.64	320.1	2.75
2013	24.19	0.06	1.22	0.12	25.59	329.1	3.60
2014	24.28	0.07	1.21	0.14	25.69	332.5	3.74
2015	24.63	0.06	1.05	0.04	25.78	337.0	3.74
2016	25.68	0.06	0.92	-0.16	26.50	341.8	4.14
2017	26.38	0.06	0.64	-0.61	26.47	344.5	4.40
2018	27.20	0.06	0.45	-1.11	26.61	346.1	4.80
2019	28.19	0.06	0.22	-1.62	26.85	348.6	4.66
2020	29.09	0.06	0.00	-1.93	27.23	352.5	4.38
2021	29.70	0.06	-0.13	-2.17	27.47	354.6	4.67
2022	30.19	0.06	-0.32	-2.17	27.77	358.0	4.82
2023	30.92	0.06	-0.51	-2.37	28.11	362.2	4.96
2024	31.44	0.06	-0.62	-2.57	28.31	365.1	5.12
2025	31.86	0.06	-0.84	-2.57	28.52	368.5	5.23
2026	32.47	0.06	-0.97	-2.77	28.79	372.4	5.36
2027	33.07	0.06	-1.14	-2.97	29.02	375.4	5.49
2028	33.65	0.06	-1.28	-3.17	29.27	378.4	5.59
2029	34.09	0.06	-1.42	-3.35	29.39	380.6	5.78
2030	34.43	0.06	-1.57	-3.37	29.56	382.6	6.03
2031	34.66	0.06	-1.67	-3.37	29.69	385.2	6.17
2032	35.04	0.06	-1.87	-3.37	29.86	387.5	6.36
2033	35.39	0.06	-1.97	-3.37	30.12	389.6	6.59
2034	35.73	0.06	-2.04	-3.37	30.38	391.9	6.74
2035	36.09	0.06	-2.16	-3.37	30.63	393.6	6.92
2036	36.36	0.06	-2.25	-3.37	30.80	394.7	7.18
2037	36.68	0.06	-2.31	-3.37	31.06	397.5	7.23
2038	37.04	0.06	-2.39	-3.37	31.34	399.6	7.26
2039	37.36	0.06	-2.48	-3.37	31.57	401.6	7.42
2040	37.54	0.06	-2.43	-3.37	31.81	402.6	7.65

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

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).

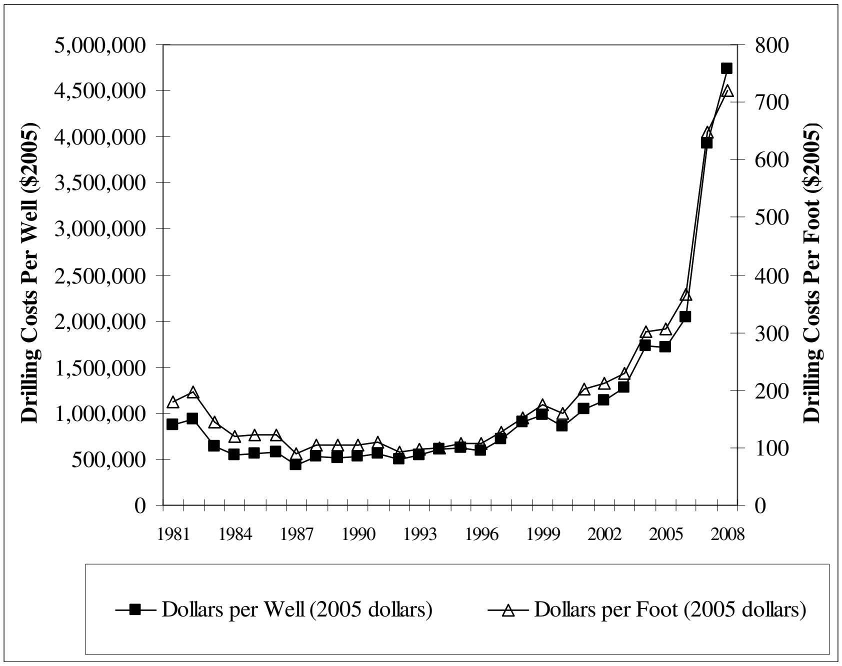

Figure 2-7 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly 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. 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 and offshore and foreign finding costs for the sample of U.S. firms in 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 and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

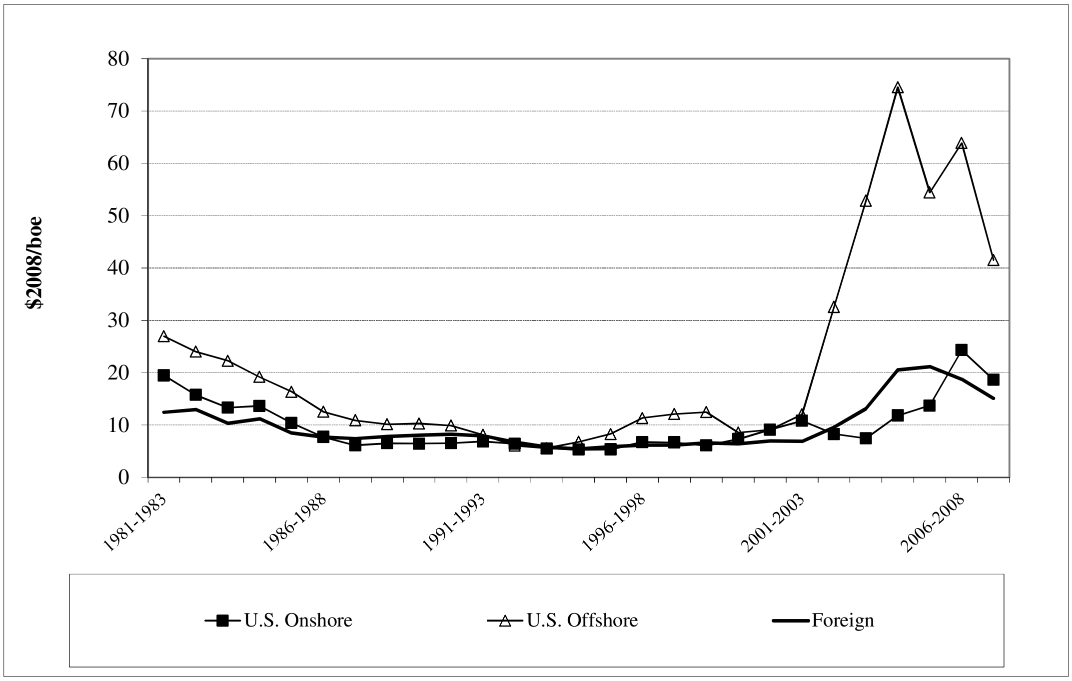

Figure 2-8 Finding Costs for FRS Companies, 1981-2009

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and 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.

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. 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, 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.

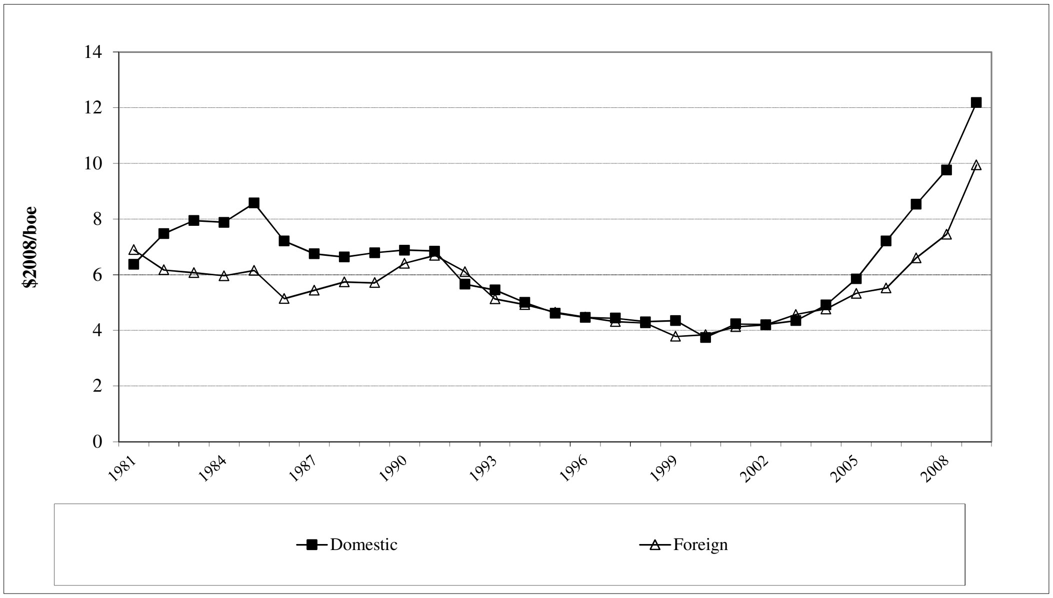

Figure 2-9 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 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, as foreign lifting costs were lower than domestic costs during this period. 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.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[11], 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

[11] 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.

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, while 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.

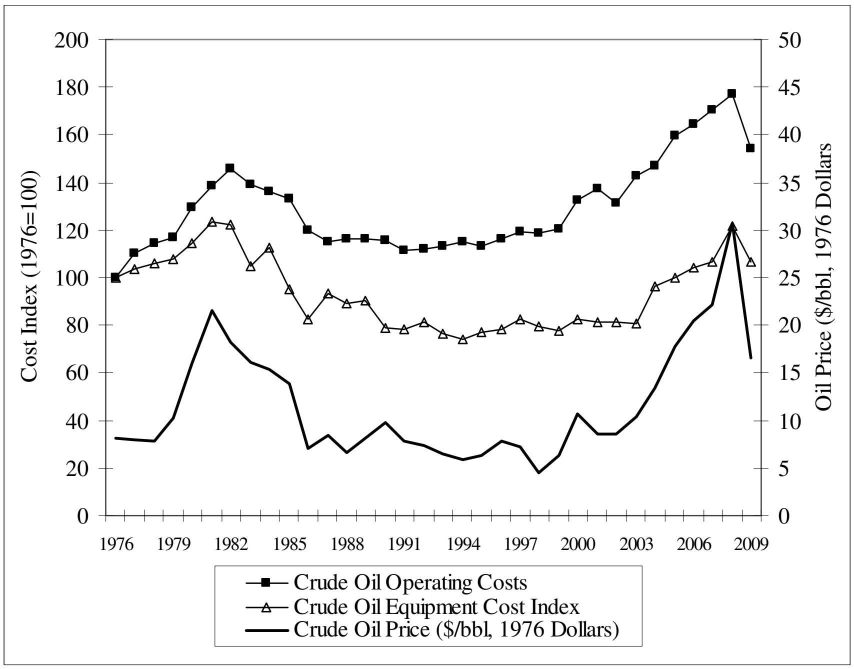

Figure 2-10 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009[12]

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

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

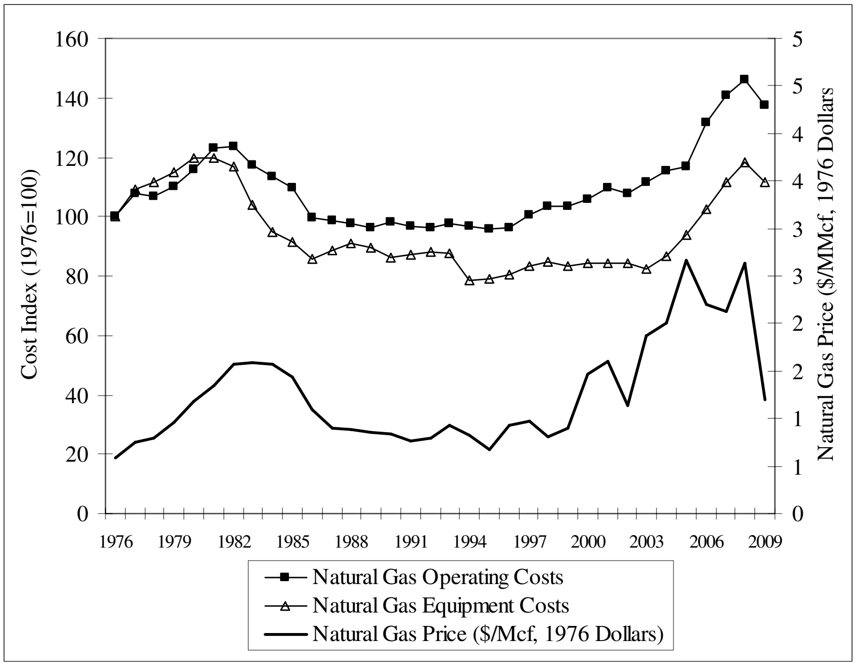

Figure 2-11 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

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.

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 plant 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 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). 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 2014, there were 6,659 firms within the 211111 and 211112 NAICS codes, of which 6,535 (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 about 60 percent of employment listed under these NAICS.

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	6,436	87	6,523
211112	Natural Gas Liquid Extraction	500	99	37	136
213111	Drilling Oil and Gas Wells	500	1,993	48	2,041
213112	Support Activities for Oil and Gas Operations	$38.5 million	N/A	N/A	8,119
486210	Pipeline Transportation of Natural Gas	$27.5 million	N/A	N/A	107
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	45,641	63,313	108,954
211112	Natural Gas Liquid Extraction	500	1,733	8,272	10,005
213111	Drilling Oil and Gas Wells	500	36,663	57,843	94,506
213112	Support Activities for Oil and Gas Operations	$38.5 million	N/A	N/A	219,827
486210	Pipeline Transportation of Natural Gas	$27.5 million	N/A	N/A	27,151

Source: U.S. Small Business Administration Office of Advocacy. 2014.
Firm Size Data. <Available at https://www.sba.gov/advocacy/firm-size-data> Accessed January 5, 2015.
Note: "N/A" indicates where national counts of small and large firms could not be performed.

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 61 percent of employment. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

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 2013. 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 2013 peak of 620,000. 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, 1990-2013

	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

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2013 , <http://www.bls.gov/cew/>

From 1990 to 2013, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2013 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2013 (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	74,475	69,877	44,193	48,010	71,231	64,452	62,245
1991	75,980	69,993	45,593	49,578	72,277	68,228	63,886
1992	80,222	72,285	45,683	51,355	77,941	70,472	67,435
1993	81,214	72,237	47,486	52,649	76,445	70,777	67,734
1994	82,976	74,277	46,717	52,565	79,790	71,804	68,058
1995	85,341	70,873	48,462	53,294	82,717	75,418	69,634
1996	88,319	72,256	51,256	55,400	80,589	80,103	71,727
1997	94,309	83,369	54,754	58,343	82,305	86,858	75,355
1998	97,870	94,427	55,692	60,445	83,028	88,367	77,393
1999	103,235	93,852	57,216	62,756	86,626	99,119	82,969
2000	115,018	117,477	63,787	63,505	84,994	136,907	90,990
2001	116,417	116,513	64,792	64,298	87,363	128,243	89,416
2002	115,314	108,703	65,226	62,847	91,763	96,010	86,240
2003	116,161	118,322	64,095	64,368	91,788	96,109	86,714
2004	127,324	124,374	66,251	65,672	98,381	98,485	90,960
2005	133,920	134,419	74,486	70,753	96,906	95,017	95,030
2006	145,658	140,685	78,047	74,085	96,693	104,055	100,084
2007	143,266	140,329	86,705	76,099	101,516	111,476	101,724
2008	153,155	132,582	86,845	78,432	107,836	105,127	105,011
2009	141,752	131,508	85,854	74,579	106,188	106,598	102,193
2010	152,074	131,980	86,297	77,774	108,855	112,857	106,522
2011	156,035	120,939	91,885	81,441	114,710	116,266	108,863
2012	155,735	136,352	92,266	80,222	120,292	139,127	108,872
2013	153,095	122,787	92,737	80,516	116,215	116,621	107,028

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2013, annual wages per employee <http://www.bls.gov/cew/>

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.

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 increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. 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 independents have to rely only 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, now the top 150. In 2012, 134 public companies are listed; in 2011there were 145 firms.[13] The 2012 list contains four companies that were not on the list in the previous year. Also, 10 other companies listed in 2011do not appear on the 2012 list as a result of mergers, bankruptcies, or other reasons. Table 2-19 lists selected statistics for the top 20 companies in 2012. The results presented in the table reflect a decline in U.S. natural gas and natural gas liquids prices, weak energy demand growth, and increased capital and operating costs in 2012.

Net income for the top 134 companies fell between 2011 and 2012 from $114.5 billion to $91.1 billion. Revenues for these companies fell 1.4 percent from 2011 to 2012. Even though earnings decreased in 2012, strong earnings from 2011 boosted available financial resources and the companies continued to invest. Capital and exploratory spending for the companies in 2012 totaled $206.5 billion, up 17.1 from 2011.

The total worldwide liquids production for the 134 firms increased 6.85 percent to 2.879 billion bbl, while total worldwide gas production increased 2.4 percent to a total of 17.4 tcf (*Oil and Gas Journal*, September 2, 2013). Meanwhile, the 134 firms on the OGJ list increased both oil and natural gas production and reserves from 2011 to 2012. Domestic production of liquids increased about 19.8 percent from 2011 to 1.437 billion bbl, and natural gas production was up about 6.3 percent. For context, the OGJ150 domestic crude production represents about 49 percent of total domestic production (2.06 billion bbl, according to EIA). The OGJ150 natural gas production represents about 69 percent of total domestic production (28.5 tcf, according to

[13] Oil and Gas Journal. “OGJ150 Earnings Down as US Production Climbs.” September 2, 2013.

EIA).

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 throughout 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, as large firms own multiple facilities, which also tend to be relatively large facilities (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 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012

Rank by Total Assets	Company	Employees	Total Assets ($Million)	Total Revenue ($Million)	Net Income ($Million)	Worldwide Production Liquids (Million bbl)	Worldwide Production Natural Gas (Bcf)	US Production Liquids (Million bbl)	US Production Natural Gas (Bcf)	Net Wells Drilled
1	ExxonMobil Corp.	76,900	333,795	482,295	47,681	625	2,992	166	1,518	1,411
2	Chevron Corp.	17,418	232,982	241,909	26,336	536	1,737	151	1,129	1,272
3	ConocoPhillips	16,900	117,144	62,004	8,498	271	1,539	120	916	1,163
4	Occidental Petroleum Corp.	12,300	64,210	24,253	4,598	201	1129	100	752	1,016
5	Apache Corp.	5,976	60,737	17,078	2,001	145	938	84	685	958
6	Anadarko Petroleum Corp.	5,200	52,589	13,411	2,445	115	916	75	565	951
7	Hess Corp.	14,775	43,441	38,373	2,063	110	839	61	440	826
8	Devon Energy Corp.	5,700	43,326	9,502	-206	103	565	57	407	769
9	Chesapeake Energy Corp.	12,000	41,611	12,316	-594	93	557	49	380	751
10	Marathon Oil Corp.	3,367	35,306	16,221	1582	78	470	45	380	699
11	EOG Resources Inc.	2,650	27,337	11,683	570	49	416	39	313	513
12	Noble Energy Inc.	2,190	17,554	4,223	1027	42	380	34	300	492
13	Murphy Oil Corp.	9,185	17,523	28,626	971	41	322	26	259	468
14	Plains Exploration and Production Co	906	17,298	2,565	343	34	284	25	253	439
15	Pioneer Natural Resources Co.	3,667	13,069	3,228	243	26	259	24	249	367
16	Linn Energy LLC	1,136	11,451	1,774	-387	25	253	24	249	334
17	Denbury Resources Inc.	1,432	11,139	2,456	525	24	249	24	183	315
18	Sandridge Energy Inc.	2,510	9,791	2,731	247	24	249	20	161	297
19	WPX Energy Inc.	1,200	9,456	3,189	-211	22	244	18	160	271
20	Continental Resources Inc.	753	9,140	2,573	416	20	183	18	156	263

Source: Oil and Gas Journal. “OGJ150 Earnings Down as US Production Climbs.” September 2, 2013. 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.

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 162 companies in 2011 (*Oil and Gas Journal*, September 2, 2013). 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 2012. 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 pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 61 percent of the total pipeline mileage and transport about 56 percent of the volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $12.1 billion, representing 59 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 59 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2012

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Operating Revenue ($000s)	Net Income ($000s)
1	Dominion Transmission Inc.	3,687	653,272	903,404	256,010
2	Texas Eastern Transmission LP	9,563	1,747,856	956,536	242,277
3	Florida Gas Transmission Co. LLC	5,336	979,857	775,375	204,968
4	Transcontinental Gas Pipe Line Co. LLC	9,378	3,274,209	1,254,154	194,573
5	Tennessee Gas Pipeline Co.	13,780	2,626,030	1,015,928	190,970
6	Columbia Gas Transmission LLC	9,708	1,305,728	813,185	186,594
7	Natural Gas Pipeline Co of America	8,911	1,511,844	687,366	176,447
8	Southern Natural Gas Co.	7,079	1,005,151	584,828	162,275
9	ETC Tiger Pipeline LLC	196	546,137	279,572	134,934
10	Northern Natural Gas Co.	14,949	928,977	587,768	134,715
11	Panhandle Eastern Pipe Line Co., LP	6,406	581,926	338,787	123,392
12	Texas Gas Transmission LLC	5,880	1,052,070	417,809	106,994
13	Kern River Gas Transmission Co.	1,718	928,206	383,393	105,447
14	Rockies Express Pipeline LLC	1,698	822,587	786,225	103,427
15	CenterPoint Energy Gas Transmission Co., LLC	5,954	1,143,552	437,836	103,290
16	Colorado Interstate Gas Co.	4,253	788,905	397,292	100,902
17	Dominion Cove Point LNG, LP	136	82989	281,517	97,192
18	Gulf South Pipeline Co., LP	6,484	1,115,618	470,149	93,816
19	Northern Border Pipeline Co.	1,408	1,008,857	310,869	89,767
20	Northwest Pipeline GP	3,906	658,161	437,835	87,119
	TOTAL FOR TOP 20	120,430	22,761,932	12,119,828	2,895,109
	TOTAL FOR ALL COMPANIES	198,279	40,759,824	20,545,763	4,888,125

Source: Oil and Gas Journal. "US Pipeline Operators Sink Revenue Growth into Expansion." September 2, 2013.

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 U.S. major energy producing companies and reports summary information in the publication "The Performance Profiles of Major Energy Producers".[14] This information is used in annual report to Congress, as well as is released to the

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

public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated. For 2009, there are 30 companies in the FRS[15] that 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 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising until 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, although 2008 and 2009 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

[15] 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 expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

Table 2-23 shows in percentage terms the estimated return on investments 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 in 2008 as a highly profitable line of business for the FRS companies and declined significantly 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	12.0	4.5
U.S. Petroleum	10	13.7	8.2	0.4
Oil and Natural Gas Production	12.5	16.5	10.7	3.5
Refining/Marketing	6.6	9.3	2.6	-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	26.3	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)[16] 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.

[16] 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.

The difference between total current taxes and U.S. federal, state, and local taxes in 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.

2.7 References

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This chapter describes the emissions and engineering cost analysis for the proposed 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 overview 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 more-detailed Technical Support Document (TSD) prepared by the EPA for the reader interested in a greater level of detail.[17]

3.2 Sector Emissions Overview

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural gas industry to provide context for estimated reductions as a result of the proposed 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: 1990-2013 (published April 2015) estimates 2013 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 182 MMt CO_2 Eq. In 2013, total methane emissions from the oil and gas industry represented nearly 29 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, 2015).

It is important to note that the 2013 GHG emissions estimates do not include methane emissions from hydraulically fractured and re-fractured oil well completions due to lack of available data when the 2013 GHG Inventory estimate was developed. The estimate in this proposed rule includes an adjustment for hydraulically fractured oil wells, and such an adjustment is also being considered as a planned improvement in the 2014 Inventory (to be published April 2016). This adjustment would increase the 2013 Inventory methane estimate by

[17] U.S. EPA. 2015. 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.

about 3 MMt CO_2 Eq. The total methane emissions from Petroleum and Natural Gas Systems based on the 2013 GHG Inventory, adjusted for hydraulically fractured and re-fractured oil well completions, is approximately 185 MMt CO_2 Eq.

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. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within 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 the same two techniques that have been proven to reduce emissions from well completions: reduced emissions completions (RECs) and completion combustion. 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. Three main technical barriers limit the feasibility of RECs at some wells: proximity of pipelines, pressure of produced gas, and inert gas concentration.

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 agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps.

The TSD considers fugitive emissions from production well sites, gathering line and boosting stations, and natural gas transmission/storage compressor stations. There are 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 bled pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh. 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 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 fairly 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 another type 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 well sites 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, we identified several options for reducing methane and VOC emissions: replace natural gas-assisted pump with instrument air pump, replace natural gas-assisted pump with solar-charged direct current pump (solar pumps), replace natural gas-assisted pump with 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 potential 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 proposed NSPS. A detailed discussion of the methodology used to estimate cost impacts is presented in the TSD, which is published in the Docket.

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. The regulatory alternatives include different variations of regulatory requirements considered for inclusion in the proposed standards. Then, projections are made of the number of incrementally affected facilities for each type of equipment or facility. National emissions reductions and cost estimates result from multiplying representative factors by the number of affected facilities in each projection year. 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. Finally, national-level cost-effectiveness is calculated.

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.[18] 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. Options 1 and 2 were selected for co-proposal.

[18] The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions (RECs) in combination with combustion. This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately $70 million per year lower cost. However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

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

Emissions Point	Emissions Control	Option 1	Option 2 (proposed)	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 Pads	Monitoring and Maintenance	**Annual**	**Semiannual**	**Quarterly**
Gathering and Boosting Stations	Monitoring and Maintenance	**Semiannual**	**Semiannual**	**Quarterly**
Transmission Compressor Stations	Monitoring and Maintenance	**Semiannual**	**Semiannual**	**Quarterly**
Pneumatic Pumps				
Well Pads	Route to control	**X**	**X**	**X**
Gathering and Boosting Stations	Route to control	**X**	**X**	**X**
Transmission and Storage Compressor Stations	Route to control	**X**	**X**	**X**
Pneumatic Controllers -				
Natural Gas Transmission and Storage Stations	Emissions limit	**X**	**X**	**X**
Reciprocating Compressors				
Natural Gas Transmission and Storage Stations	Annual Monitoring and Maintenance	**X**	**X**	**X**
Centrifugal Compressors				
Natural Gas Transmission and Storage Stations	Route to control	**X**	**X**	**X**

The co-proposed 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 also requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at newly drilled or refractured oil and natural gas well sites, new or modified gathering and boosting stations, and new or modified transmission and storage compressor stations. However, low production well sites are exempt from the well site fugitive requirements. A low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.[19] Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this RIA presents a “low” impact case and “high” impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate low production sites, assuming that the fraction of wells meeting the low production criteria in the future will be the same as in 2012 (based on the first month of production data from wells newly completed or modified in 2012).The high impact case includes all forecast well sites providing a bounding case where no newly completed or modified wells meet the low production criteria. Summary results for option 2, then, are presented as ranges.

Options 1 and 3 differ from the Option 2 with respect to the requirements for fugitive emissions. Meanwhile, the co-proposed Option 1 requires annual monitoring for well sites, including low production sites, while maintaining semiannual requirements for others sites. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program, including low production sites. More frequent surveys result in higher costs, higher emissions reductions, and increased natural gas recovery over the co-proposed Option 2.

3.4.2 Projection of Incrementally Affected Facilities

The second step in estimating national costs and emissions impacts of the proposed 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 proposal. Facilities in states with similar state-level requirements are not included within incrementally affected facilities.

The years of analysis are 2020, to represent the first full year of compliance for the proposal, and 2025, to represent impacts of the proposal over a longer period of time. Affected

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[19] Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

facilities are facilities which are new or modified since the effective year of the proposal. In 2020 affected facilities are those which are newly established or modified in 2020. 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, but also facilities which were newly established or modified from 2020 through 2024 and are still operating in 2025.

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's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook.

The 2014 Annual Energy Outlook was the most recent projection available at the time that the analysis underlying this RIA was being prepared. However, since then the 2015 Annual Energy Outlook has been released by the U.S. Energy Information Administration. The 2015 AEO reflects that growth in U.S. crude oil production over the last two years, along with the late-2014 drop in global crude oil prices, have altered the economics of the oil market. In comparison to 2014 AEO reference case, the 2015 AEO reference case shows higher crude oil production (in 2025, 18 percent higher in 2015 AEO), slightly lower natural gas production (in 2025, about 4 percent lower in 2015 AEO15), lower Brent spot and West Texas Intermediate crude oil prices, and lower total wells drilled in the lower 48 states (in 2025, about 20 percent lower in 2015 AEO). If this RIA were updated to reflect the lower drilling activity in 2015 AEO, then the national costs and emissions reductions of the oil well completions and well site fugitives provisions of the rule would likely be reduced. Costs and emissions reductions per facility would not be affected, however.

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. 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. A more detailed discussion on the derivation of the baseline for the current proposal is presented for each emissions source is the TSD. The estimated counts of hydraulically-fractured and re-fracture oil well completions also account for the wells anticipated to be excluded from the proposed NSPS requirements because of a gas-to-oil ratio (GOR) of 300 or below.

Table 3-2 Number of Incrementally Affected Sources for the NSPS

	Incrementally Affected Sources	
Emissions Sources	**2020**	**2025[1]**
Hydraulically Fractured and Re-fractured Oil Well Completions	15,000	15,000
Fugitive Emissions[2]	14,000 to 22,000	86,000 to 140,000
Pneumatic Pumps	3,000	18,000
Compressors	68	410
Pneumatic Controllers	210	1,300
Total[2]	31,000 to 40,000	120,000 to 180,000

[1] In addition to newly affected sources in 2025, incrementally affected sources in 2025 include sources that become affected in the 2020-24 time period and are assumed to be in continued operation in 2025.
[2] The low end of the range in the fugitive emissions and total rows reflect the number of incrementally affected sources under the low impact co-proposed Option 2, which excludes low production well sites.

Table 3-2 presents the estimates of the number of incrementally affected sources for this proposal after accounting for state regulations as described above. 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 that hydraulically fractured and re-fractured oil well completions and fugitive emissions at well sites (a large fraction of the incrementally affected sources under the proposed rule fugitive emissions provisions) include both new and modified sources. The estimates for other sources are based upon projections of new sources alone. While some of these sources, particularly pneumatic pumps and controllers, are likely to be predominantly new sources, the impact estimates may be under-estimated by the under-represented modified sources. In the preamble to the proposed rule, the EPA solicits 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 well sites.

3.4.3 Emissions Reductions

Table 3-3 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. Table 3-1 summarizes the applicable controls, and Table 3-2 summarizes the affected facilities, aggregating multiple model plant types within each source category (e.g., oil well completions combine development and exploratory wells). The detailed description of emissions controls is provided in the TSD. Please note that all results have been rounded to two significant digits.

Table 3-3 Emissions Reductions for Proposed 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	140,000	110,000	14	63,100,000
Fugitive Emissions	24,000 to 33,000	6,200 to 8,700	230 to 330	740,000 to 750,000
Pneumatic Pumps	5,400	1,500	57	120,000
Compressors	1,600	43	1	36,000
Pneumatic Controllers	590	16	0	13,000
Total	**170,000 to 180,000**	**120,000**	**310 to 400**	**3,800,000 to 4,000,000**
	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	140,000	120,000	14	3,100,000
Fugitive Emissions	150,000 to 210,000	40,000 to 57,000	1,500 to 2,200	3,500,000 to 4,900,000
Pneumatic Pumps	32,000	9,000	340	740,000
Compressors	9,400	260	8	210,000
Pneumatic Controllers	3,500	97	3	80,000
Total	**340,000 to 400,000**	**170,000 to 180,000**	**2,200 to 2,500**	**7,700,000 to 9,000,000**

3.4.4 Product Recovery

The annualized cost estimates presented below include revenue from additional natural gas recovery in the production and processing segments. Several emission controls for the NSPS capture methane and VOC emissions that otherwise would be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For 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 for the control.

The standards 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 low-bleed pneumatic devices. The proposed 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 Energy Information Administration’s 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be $4.46/Mcf in 2020 and $5.06/Mcf in 2025. The $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

Natural gas recovery at any point in the system provide benefits to the energy system and to the public. However, due to contractual arrangements, transmission and storage companies do not always benefit from lowering the leak rate of their operations because they do not necessarily own the gas, and fixed loss rates are included in long-term contracts. As a result, the EPA excludes revenue from natural gas recovery in estimating compliance costs for the transmission and storage segment. This approach likely overestimates the long-term compliance cost of the controls.

Table 3-4 Estimated Natural Gas Recovery (Mcf) for Proposed NSPS Option 2 in 2020 and 2025

Source/Emissions Point	2020 Gas recovery (Mcf)	2020 Revenue from recovery (millions 2012$)	2025 Gas recovery (Mcf)	2025 Revenue from recovery (millions 2012$)
Oil Well Completions and Recompletions	6,200,000	$25	6,200,000	$25
Fugitive Emissions	1,400,000 to 1,900,000	$5.1 to $7.3	8,900,000 to 12,000,000	$33 to $47
Pneumatic Pumps	0	$0	0	$0
Compressors	76,000	$0	450,000	$0
Pneumatic Controllers	30,000	$0	180,000	$0
Total	7,700,000 to 8,200,000	$30 to $32	16,000,000 to 19,000,000	$58 to $72

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. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For the proposed option, a $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $8 million in 2020 and $16 to $19 million in 2025, in 2012 dollars.

3.4.5 Engineering Compliance Costs

Table 3-6 summarizes the capital and annualized costs for the evaluated emissions sources and points. The detailed description of costs 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 3-5 Engineering Compliance Cost Estimates for Proposed NSPS Option 2 in 2020 and 2025 (millions 2012$)

Source/Emissions Point	Compliance Costs, 2020		Compliance Costs, 2025	
	Capital Costs (2012$)	Nationwide Annualized Costs (2012$)	Capital Costs (2012$)	Nationwide Annualized Costs (2012$)
Oil Well Completions and Recompletions	$150	$120	$150	$120
Fugitive Emissions	$15 to $22	$29 to $47	$95 to $140	$180 to $290
Pneumatic Pumps	$5.9	$0.84	$36.0	$5.1
Compressors	$0.54	$0.25	$3.2	$1.5
Pneumatic Controllers	$0.048	$0.0052	$0.29	$0.031
Reporting and Recordkeeping	$0.0	$1.4	$0.0	$4.1
Total	**$170 to180**	**$150 to $170**	**$280 to $330**	**$320 to $420**

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:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section)
- Fugitive emissions monitoring program design: 8 years
- Reciprocating compressors rod packing: 3.8 – 4.4 years
- Centrifugal compressors, pneumatic controllers, and pneumatic pumps: 10 years

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this proposed rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Chapter 5 for more detail). The 2020 reporting and recordkeeping costs in this RIA ($1.4 million) are based on the first year ICR cost estimates. Meanwhile, we drew upon the first year cost in the ICR cost estimates ($4.1 million) and applied that cost to 2025 in this RIA.

3.4.6 Cost-Effectiveness

This section summarizes the cost-effectiveness of the proposed standards for each source in 2020 and 2025. The proposed NSPS includes standards for both methane and VOC reductions.

As discussed in the preamble to this action, cost-effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the benefit produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a cost-benefits analysis but rather provides a metric of the relative cost to reduction ratios of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure controls a single pollutant. Increasingly, however, air pollution reduction programs require reductions in emissions of multiple pollutants, and in such programs multipollutant controls may be employed. Consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants). This is the case for the current proposal where the EPA is proposing to directly regulate both methane and VOC.

To assign the entire annualized cost to the reduction in emissions of a single pollutant reduced by the multipollutant control option is appropriate when reductions of the other pollutants are considered to cobenefits with no cost. However, under the current proposal, methane and VOCs are both directly regulated; therefore, reductions of each pollutant must be properly considered benefits, not co-benefits, and consideration of only one of the regulated pollutants is not appropriate.

Alternatively, all annualized costs can be allocated to each of the pollutant emission reductions addressed by the multipollutant control option. Unlike the approach above, no emission reduction is treated as a co-benefit; each emission reduction is assessed based on the full cost of the control. However, this approach, which is often used for assessing single-pollutant controls, evaluates emission reduction of each pollutant separately, assuming that each bears the entire cost, and thus inflates the control cost in the multiple of the number of additional pollutants being reduced. This approach therefore over-estimates the cost of obtaining emissions reductions with a multipollutant control as it does not recognize the simultaneity of the reductions achieved by the application of the control option. Another approach allocates the annualized cost to the sum of the individual pollutant emission reductions addressed by the multipollutant control option. The multipollutant cost-effectiveness approach may be appropriate when each of the pollutant reductions is similar in value or impact. However, in the current proposal, methane and VOC have quite different health and environmental impacts, and therefore summing the pollutants to derive the denominator of the cost-effectiveness equation (i.e., assuming a ton of methane is equivalent in its impacts to a ton of VOC) is inappropriate.

For purposes of this proposal, we have identified and are proposing to use two approaches for considering the cost of reducing emissions from multiple pollutants using one control. One approach is to assign all costs to the emission reduction of one pollutant and zero to all other concurrent reductions; if the cost is reasonable for reducing any of the targeted emissions alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other pollutants because they are being reduced at no additional cost. While this approach assigns all costs to only a portion of the emission reduction, it does not overstate the cost. It also does not require unreasonable assumptions about the equivalency of the impacts between a ton of methane and VOC emission reduction, which is not appropriate as discussed in the option immediately above. In addition, this approach is simple and straight forward in application. If the multipollutant control is cost effective for reducing emissions of either of the targeted pollutant, it is clearly cost effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term a "multipollutant cost-effectiveness" approach, apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled by mass. For example, in this proposal both methane and VOC emissions are reduced in equal proportion by the multipollutant control option. As a result, half of the control costs are allocated to methane, the other half to VOC. This approach similarly does not inflate the control cost nor requires unreasonable assumptions about the equivalency of the impacts between a ton of methane and VOC emission reduction.

We believe that both approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. As such, in our analyses below, if a device is cost effective under either of these two approaches, we find it to be cost effective. The EPA recognize, however, not all situations where multipollutant controls are applied are the same, and that other approaches, including those described above as inappropriate for this action, might be appropriate in other instances.

Under the single pollutant cost-effectiveness approach, the total national compliance costs are divided by the emissions reductions for methane and VOC separately (Table 3-6). This approach does not account for the combined emissions reductions of both pollutants. We only present the cost-effectiveness for the high impact case for fugitive emissions requirements at well sites. The low impact case would show lower dollar per ton estimates.

Table 3-6 Single Pollutant Approach to Engineering Compliance Cost-Effectiveness Estimates in 2020 and 2025 for Proposed NSPS Option 2 (High Impact Case for Well Site Fugitive Emissions Requirements)

	Cost-Effectiveness, 2020 (2012$)			**Cost-Effectiveness, 2025 (2012$)**		
Source/ Emissions Point	Methane ($/short ton)	VOC ($/short ton)	Methane ($/metric ton CO_2 Eq.)	Methane ($/short ton)	VOC ($/short ton)	Methane ($/metric ton CO_2 Eq.)
Oil Well Completions	$910	$1,100	$40	$900	$1,100	$39
Fugitive Emissions	$1,400	$5,300	$62	$1,400	$5,100	$60
Pneumatic Pumps	$160	$560	$7	$160	$560	$7
Compressors	$160	$5,600	$7	$160	$5,600	$7
Pneumatic Controllers	$9	$320	$0	$9	$320	$0
Total	**$980**	**$1,400**	**$43**	**$1,100**	**$2,300**	**$47**

For the multipollutant cost-effectiveness approach, costs are allocated proportionally to methane and VOC reductions based on the percent reduction achieved in each pollutant (Table 3-7). Because the relevant oil and gas controls reduce methane and VOC in equal proportion, 50 percent of costs are allocated to each emission.

Table 3-7 Multipollutant Approach to Engineering Compliance Cost-Effectiveness Estimates for Proposed NSPS Option 2 in 2020 and 2025 (High Impact Case for Well Site Fugitive Emissions Requirements)

	Cost-Effectiveness, 2020 (2012$)			Cost-Effectiveness, 2025 (2012$)		
Source/ Emissions Point	Methane ($/short ton)	VOC ($/short ton)	Methane ($/metric ton CO_2 Eq.)	Methane ($/short ton)	VOC ($/short ton)	Methane ($/metric ton CO_2 Eq.)
Oil Well Completions	$450	$540	$20	$450	$530	$20
Fugitive Emissions	$710	$2,700	$31	$680	$2,500	$30
Pneumatic Pumps	$78	$280	$3	$78	$280	$3
Compressors	$78	$2,800	$3	$78	$2,800	$3
Pneumatic Controllers	$5	$160	$0	$5	$160	$0
Total	**$490**	**$690**	**$22**	**$530**	**$1,200**	**$24**

3.4.7 Comparison of Regulatory Alternatives

Table 3-8 presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025.[20] The requirements between the options vary with respect to the fugitive emissions requirements. Option 1 includes requirements for annual fugitive emissions surveys at well sites but semiannual frequency at other sites, and Option 3 includes requirements for quarterly fugitive emissions surveys, as opposed the semiannual requirement in Options 2. Annual, semiannual, and quarterly fugitive emissions surveys are assumed to result in respective reductions in emissions of 40 percent, 60 percent, and 80 percent, but affect the same number of sources. 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.

[20] The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions in combination with combustion (RECs). This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately $70 million per year lower cost. However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

Table 3-8 Comparison of Regulatory Alternatives

	Regulatory Alternative		
	Option 1	Option 2 (proposed)	Option 3
Impacts in 2020			
Affected Sources	40,000	31,000 to 40,000	40,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	170,000	170,000 to 180,000	190,000
VOC Emissions Reduction (short tons/year)	120,000	120,000	130,000
Natural Gas Recovery (Mcf)	7,700,000	7,700,000 to 8,200,000	8,800,000
Compliance Costs			
Capital Costs (2012$)	$180,000,000	$170,000,000 to $180,000,000	$180,000,000
Annualized Costs (2012$)	$150,000,000	$150,000,000 to $170,000,000	$210,000,000
Cost-Effectiveness (Single Pollutant Approach)[1]			
Methane (2012$ / short ton)	$920	$920 to $980	$1,100
VOC (2012$ / short ton)	$1,300	$1,300 to $1,400	$1,700
Cost-Effectiveness (Multipollutant Approach)[1]			
Methane (2012$ / short ton)	$460	$460 to $490	$570
VOC (2012$ / short ton)	$630	$640 to $690	$840
Impacts in 2025			
Affected Sources	180,000	120,000 to 180,000	180,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	340,000	340,000 to 400,000	470,000
VOC Emissions Reduction (short tons/year)	170,000	170,000 to 180,000	200,000
Natural Gas Recovery (Mcf)	16,000,000	16,000,000 to 19,000,000	23,000,000
Compliance Costs			
Capital Costs (2012$)	$330,000,000	$280,000,000 to $330,000,000	$330,000,000
Annualized Costs (2012$)	$310,000,000	$320,000,000 to $420,000,000	$680,000,000
Cost-Effectiveness (Single Pollutant Approach)[1]			
Methane (2012$ / short ton)	$920	$940 to $1,100	$1,400
VOC (2012$ / short ton)	$1,900	$1,900 to $2,300	$3,400
Cost-Effectiveness (Multipollutant Approach)[1]			
Methane (2012$ / short ton)	$460	$470 to $530	$720
VOC (2012$ / short ton)	$940	$960 to $1,200	$1,700

[1] Cost-effectiveness based on high impact case for well site fugitive emissions requirements.

3.4.8 Capital and Annualized Compliance Costs Compared to Industry-level Capital Expenditures and Revenues

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of "Best System of Emission Reduction" (BSER) for the proposed standards, we analyzed the total cost of the rule for each type of affected facility under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey[21]. For the capital expenditures analysis, we determined the estimated nationwide capital costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide capital costs by the new capital expenditures (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICs codes that correspond to oil and natural gas production segment. Table 3-9 below summarizes the capital expenditure data used for our analysis.

Table 3-9 NAICS-Based Capital Expenditure Data

Oil and Natural Gas Segment	NAICS Code	NAICS Description	Total New Expenditures (millions, current $)
Production	2111	Crude Petroleum and Natural Gas Extraction	$158,911
	213111, 213112	Support Activities for Oil and Gas Operations	$19,966
Transmission and Storage	4862	Pipeline transportation of natural gas	$12,891

[21] Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See http://www.census.gov/econ/aces/xls/2013/full_report.html

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. First year costs, which are corporate-based costs for these standards are factored into the annual costs; however, these first year costs are not actual capital costs and we therefore, determined that comparison of these costs to industry capital expenditures would be inappropriate.

In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us determine whether the annualized costs appear reasonable as a percentage of the revenues being generated by the industry. The annualized costs, as calculated for the rule, include capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We used annual costs without savings from natural gas recovery in order to present the highest costs. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census[22]. For the annual revenues analysis, we determined the estimated nationwide annualize costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICs codes that correspond to oil and natural gas production segment. Table 3-10 below summarizes the revenue data used for our analysis.

Table 3-10 NAICS-Based Revenue Data

Oil and Natural Gas Segment	NAICS Code	NAICS Description	Estimated Receipts (millions 2012$)
Production	211111	Crude Petroleum and Natural Gas Extraction	$276,077
	213112	Support Activities for Oil and Gas Operations	$90,646
Processing	211112	Natural Gas Liquid Extraction	$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	$26,587

[22] Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see http://www.census.gov/econ/susb/methodology.html. For definitions of estimated receipts and other definitions, see http://www.census.gov/econ/susb/definitions.html.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline Transportation of Natural Gas". Although there is not a one-to-one correspondence between NAICS codes and the industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware that different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 3-11 summarizes the result of our analysis. In all cases we found that the impacts of the proposed rule in comparison to either capital expenditures or revenues represent a fraction of one percent.

Table 3-11 Comparison of Proposed NSPS Nationwide Cost by Affected Facility Cost to Industry-wide Capital Expenditures and Revenues

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs (millions 2012$)	Total Nationwide Annual Cost (millions 2012$)	Nationwide Capital Cost / Capital Expenditures (%)	Nationwide Annual Cost / Receipts (%)
Production					
Hydraulically Fractured Oil Well Completions and Recompletions					
- Development Oil Wells	13,804	$144	$144	0.08%	0.03%
- Exploratory/Delineation Oil Wells	1,166	$4	$4	0.00%	0.00%
Gas-Driven Pumps	17,760	$36	$5	0.02%	0.00%
Fugitives - Well Sites	138,568	NA	$310	NA	0.09%
Total Production Segment	171,298	$184	$464	0.10%	0.13%
Transmission and Storage					
Compressors					
- Reciprocating	402	$2.80	$0.79	0.02%	0.00%
- Centrifugal	6	$0.14	$0.02	0.01%	0.00%
Pneumatic Controllers	1,260	$0.29	$0.03	0.00%	0.00%
Fugitives - Compressor Stations	1,680	NA	$27	NA	0.10%
Total Transmission and Storage Segment	3,348	$3	$28	0.03%	0.11%

Source : All cost information is from the "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 New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Recompletions from Table 4-8, for Gas Driven Pumps from Table 7-19, for Fugitives - Well sites from Table 5-31, for Compressors, Reciprocating from Table 8-13,for Centrifugal from Table8-14, for Pneumatic controllers from- Table 6-9, and for Fugitives - Compressor Stations from Table 5-31.

3.5 Compliance Costs Estimated using 3 and 7 Percent Discount Rates

Table 3-9 shows that the choice of discount rate has very minor effects on the nationwide annualized costs of the proposed option.

Table 3-12 Annualized Costs using 3 and 7 Percent Discount Rates for Proposed NSPS Option 2 in 2020 and 2025 (millions 2012$)

	Nationwide Annualized Costs, 2020 (2012$)		Nationwide Annualized Costs, 2025 (2012$)	
	7 percent	**3 percent**	**7 percent**	**3 percent**
Oil Well Completions and Recompletions	$120	$120	$120	$120
Fugitive Emissions	$29 to $47	$29 to $46	$180 to 290	$180 to $290
Pneumatic Pumps	$0.84	$0.69	$5.1	$4.2
Compressors	$0.25	$0.23	$1.5	$1.4
Pneumatic Controllers	$0.0052	$0.0040	$0.031	$0.024
Reporting and Recordkeeping	$1.4	$1.4	$4.1	$4.1
Total	**$150 to $170**	**$150 to $170**	**$320 to $420**	**$310 to $420**

The choice of discount rate has a small effect on nationwide annualized 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 proposal.

3.6 Detailed Impacts Tables

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

Table 3-13 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020

		Nationwide Emissions Reductions				National Costs (2012$)	
Source/Emissions Point	Incrementally Affected Units	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	$3,200,000	$3,200,000
Fugitive Emissions							
Well Pads	22,000	17,000	4,800	180	390,000	$18,000,000	$25,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	$4,200,000	$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	$340,000	$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	$5,900,000	$840,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	$470,000	$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	$72,000	$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	$48,000	$5,200
Reporting and Recordkeeping	All	0	0	0	0	$0	$1,400,000
TOTAL	**40,000**	**170,000**	**120,000**	**310**	**3,800,000**	**$180,000,000**	**$150,000,000**

Table 3-14 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025

		Nationwide Emissions Reductions				National Costs (2012$)	
Source/Emissions Point	Incrementally Affected Units	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	$4,300,000	$4,300,000
Fugitive Emissions							
Well Pads	140,000	110,000	32,000	1,200	2,600,000	$110,000,000	$160,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	$25,000,000	$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	$2,100,000	$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	$36,000,000	$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	$2,800,000	$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	$430,000	$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	$290,000	$31,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$4,100,000
TOTAL	**180,000**	**340,000**	**170,000**	**1,900**	**7,700,000**	**$330,000,000**	**$310,000,000**

Table 3-15 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, Low Impact Case, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	$3,200,000	$3,200,000
Fugitive Emissions							
Well Pads	13,000	17,000	4,600	180	380,000	$11,000,000	$26,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	$4,200,000	$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	$340,000	$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	$5,900,000	$840,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	$470,000	$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	$72,000	$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	$48,000	$5,200
Reporting and Recordkeeping	All	0	0	0	0	$0	$1,400,000
TOTAL	**31,000**	**170,000**	**120,000**	**310**	**3,800,000**	**$170,000,000**	**$150,000,000**

Table 3-16 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, Low Impact Case, 2025

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	$4,300,000	$4,300,000
Fugitive Emissions							
Well Pads	84,000	110,000	31,000	1,200	2,500,000	$68,000,000	$160,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	$25,000,000	$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	$2,100,000	$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	$36,000,000	$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	$2,800,000	$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	$430,000	$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	$290,000	$31,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$4,100,000
TOTAL	**120,000**	**340,000**	**170,000**	**1,900**	**7,700,000**	**$280,000,000**	**$320,000,000**

Table 3-17 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, High Impact Case, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	$3,200,000	$3,200,000
Fugitive Emissions							
Well Pads	22,000	26,000	7,200	270	590,000	$18,000,000	$43,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	$4,200,000	$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	$340,000	$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	$5,900,000	$840,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	$470,000	$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	$72,000	$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	$48,000	$5,200
Reporting and Recordkeeping	All	0	0	0	0	$0	$1,400,000
TOTAL	**40,000**	**180,000**	**120,000**	**400**	**4,000,000**	**$180,000,000**	**$170,000,000**

Table 3-18 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, High Impact Case, 2025

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	$4,300,000	$4,300,000
Fugitive Emissions							
Well Pads	140,000	170,000	48,000	1,800	3,900,000	$110,000,000	$270,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	$25,000,000	$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	$2,100,000	$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	$36,000,000	$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	$2,800,000	$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	$430,000	$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	$290,000	$31,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$4,100,000
TOTAL	**180,000**	**400,000**	**180,000**	**2,500**	**9,000,000**	**$330,000,000**	**$420,000,000**

Table 3-19 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	$3,200,000	$3,200,000
Fugitive Emissions							
Well Pads	22,000	34,000	9,600	360	780,000	$18,000,000	$81,000,000
Gathering and Boosting Stations	260	7,300	2,000	76	170,000	$4,200,000	$5,400,000
Transmission Compressor Stations	21	2,300	63	2	52,000	$340,000	$780,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	$5,900,000	$840,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	$470,000	$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	$72,000	$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	$48,000	$5,200
Reporting and Recordkeeping	All	0	0	0	0	$0	$1,400,000
TOTAL	**40,000**	**190,000**	**130,000**	**510**	**4,200,000**	**$180,000,000**	**$210,000,000**

Table 3-20 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025

Source	Incrementally Affected Units	Nationwide Emissions Reductions: Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	National Costs (2012$): Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	$140,000,000	$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	$4,300,000	$4,300,000
Fugitive Emissions							
Well Pads	140,000	230,000	64,000	2,400	5,200,000	$110,000,000	$510,000,000
Gathering and Boosting Stations	1,600	44,000	12,000	460	990,000	$25,000,000	$32,000,000
Transmission Compressor Stations	130	14,000	380	11	310,000	$2,100,000	$4,700,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	$36,000,000	$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	$0	$0
Transmission and Storage Compressor Stations	0	0	0	0	0	$0	$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	$2,800,000	$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	$430,000	$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	$290,000	$31,000
Reporting and Recordkeeping	All	0	0	0	0	$0	$4,100,000
TOTAL	**180,000**	**470,000**	**200,000**	**3,200**	**11,000,000**	**$330,000,000**	**$680,000,000**

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed NSPS amendments are expected to prevent new emissions from the oil and gas sector. For the proposed NSPS, there will be climate benefits from methane reductions, ozone and $PM_{2.5}$ health benefits from VOC reductions, and HAP "co-benefits". These co-benefits occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions. The proposed NSPS is anticipated to prevent 170,000 to 180,000 tons of methane, 120,000 tons of VOC, and 310 to 400 tons of HAP from new sources in 2020. In 2025, the NSPS would prevent 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are estimated to be 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 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 $200 to $210 million and $460 to $550 million using a 3 percent discount rate in 2020 and 2025, respectively. The specific control techniques for the proposed 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 system 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 a 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 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 Proposal

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 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 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 Proposed 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, well sites, 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 the 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 that 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 emission reductions anticipated for this rule, across the regulatory options examined in the rule. 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. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these 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 (proposed)	Option 3
		2020	
Methane (short tons/year)	170,000	170,000 to 180,000	190,000
VOC (short tons/year)	120,000	120,000	130,000
HAP (short tons/year)	310	310 to 400	510
Methane (metric tons)	150,000	150,000 to 160,000	170,000
Methane (metric tons CO_2 Eq.)	3,800,000	3,800,000 to 4,000,000	4,200,000
		2025	
Methane (short tons/year)	340,000	340,000 to 400,000	470,000
VOC (short tons/year)	170,000	170,000 to 180,000	200,000
HAP (short tons/year)	1,900	1,900 to 2,500	3,200
Methane (metric tons)	310,000	310,000 to 360,000	430,000
Methane (metric tons CO_2 Eq.)	7,700,00	7,700,000 to 9,000,000	11,000,000

4.3 Methane

4.3.1 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 that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone 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.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (published April 2015) estimates 2013 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 182 MMt CO_2 Eq. In 2013, total methane emissions from the oil and gas industry represented nearly 29 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, 2015c).

It is important to note that the 2013 GHG emissions estimates do not include methane emissions from hydraulically fractured and re-fractured oil well completions due to lack of available data when the 2013 GHG Inventory estimate was developed. The estimate in this proposed rule includes an adjustment for hydraulically fractured oil wells, and such an adjustment is also being considered as a planned improvement in the 2014 Inventory (to be published April 2016). This adjustment would increase the 2013 Inventory methane estimate by about 3 MMt CO_2 Eq. The total methane emissions from Petroleum and Natural Gas Systems based on the 2013 GHG Inventory, adjusted for hydraulically fractured and re-fractured oil well completions, is approximately 185 MMt CO_2 Eq.

Actions taken to comply with the proposed NSPS are anticipated to significantly decrease methane emissions from the oil and natural gas sector in the United States. The proposed NSPS is expected to reduce methane emissions by about 170,000 to 180,000 short tons or approximately 150,000 to 160,000 metric tons methane (or 3.8 to 4.0 MMt CO_2 Eq.) in 2020. In 2025, the proposed NSPS is expected to reduce methane emissions by about 340,000 to 400,000 short tons or approximately 310,000 to 360,000 metric tons methane (or 7.7 to 9.0 MMt CO_2 Eq.). These reductions in 2020 and 2025 represent about 2 percent and 4 to 5 percent, respectively, of the GHG emissions for this sector (excluding petroleum refineries and petroleum transportation) reported in the 1990-2013 U.S. GHG Inventory (182 MMt CO_2 Eq.).

We calculated the global social benefits of methane emissions reductions expected from the proposed 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 to the SC-CH_4, it 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. It is used to quantify the benefits of reducing CO_2 emissions, or the disbenefit from increasing emissions, in regulatory impact analyses.

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 $SC\text{-}CO_2$ 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 $SC\text{-}CO_2$ Technical Support Document (2010 $SC\text{-}CO_2$ TSD) provides a complete discussion of the methods used to develop these estimates and the current $SC\text{-}CO_2$ TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[26]

The 2010 $SC\text{-}CO_2$ TSD noted a number of limitations to the $SC\text{-}CO_2$ 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 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. 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 $SC\text{-}CO_2$ estimates from stakeholders through a range of channels, including public comments on Agency rulemakings that use the $SC\text{-}CO_2$ in supporting analyses and through regular interactions with stakeholders and research analysts implementing the $SC\text{-}CO_2$ methodology used by the IWG. In addition, OMB sought public

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

comment on the approach used to develop the SC-CO_2 estimates through a separate comment period that ended on February 26, 2014.[27]

After careful evaluation of the full range of comments, the IWG continues to recommend the use of the SC-CO_2 estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academy of Sciences to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change.[28] The NRC review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the NRC process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

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).[29] 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

[27] For the IWG's response to comments, see https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf.

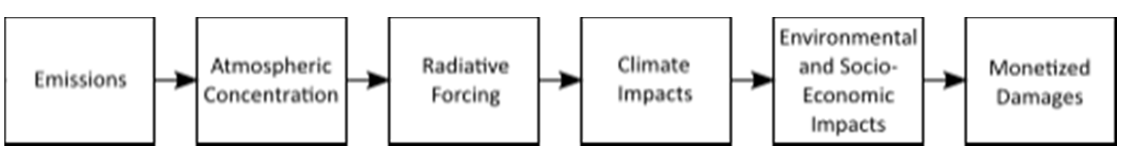
[28] See https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions.

[29] The current version of the SC-CO_2 TSD is available at: <link to be added when available>. 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.

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 higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution. 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 proposal 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 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).[30] 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. 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

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

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 used in developing the SC-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-CH_4 with a larger downward bias under higher discount rates (Marten and Newbold, 2012).[31]

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-CH_4 to overcome those challenges.

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

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-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). 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-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 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-CO_2 estimates developed by the IWG, were developed. The EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefit-cost analyses.[32]

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.[33] Specifically, the estimation approach of Marten *et al.* used 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. The atmospheric lifetime and radiative efficacy of methane used by Marten *et al.* is based on the

[32] 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

[33] Marten *et al.* (2014) also provided the first set of SC-N_20 estimates that are consistent with the assumptions underlying the SC-CO_2 estimates.

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 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 how biogenic and fossil methane have different carbon cycle effects, and for 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).[34,35]

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.[36] 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

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[34] *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.

[35] Note that this proposal 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).

[36] 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.

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.*

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 proposed rulemaking. Forecast changes in methane emissions in a given year, expected as a result of the proposed 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.

The EPA recently 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. Three reviewers considered seven charge questions that covered 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 in RIAs of the SC-CH_4 estimates developed by Marten *et al.* and published in the peer-reviewed literature is appropriate, 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.

In light of the favorable peer review and past comments urging the EPA to value non-CO_2 GHG impacts in its rulemakings, the Agency has used the Marten *et al.* (2014) SC-CH_4 estimates to value methane impacts expected from this proposed rulemaking and has included those benefits in the main benefits analysis. The EPA seeks comments on the use of these directly modeled estimates, from the peer-reviewed literature, for the social cost of non-CO_2 GHGs in this RIA.

The methane benefits are presented below in Table 4-4 for years 2020 and 2025 across regulatory options. Applying this approach to the methane reductions estimated for the proposed NSPS option, the 2020 methane benefits vary by discount rate and range from about $88 million to approximately $550 million; the mean SC-CH_4 at the 3 percent discount rate results in an estimate of about $200 to $210 million in 2020. The methane benefits increase for the proposed option in 2025 and likewise vary by discount rate, ranging from about $220 million to approximately $1.4 billion in that year; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $460 to $550 million in 2025.

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

Discount rate and statistic	Option 1		Proposed Option 2 (Low)		Proposed Option 2 (High)		Option 3	
	2020	2025	2020	2025	2020	2025	2020	2025
Million metric tonnes of methane reduced	0.15	0.31	0.15	0.31	0.16	0.36	0.17	0.43
Million metric tonnes of CO_2 Eq.	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11
5% (average)	$89	$220	$88	$220	$93	$250	$99	$300
3% (average)	$200	$470	$200	$460	$210	$550	$220	$640
2.5% (average)	$260	$600	$260	$600	$280	$700	$290	$830
3% (95^{th} percentile)	$530	$1,200	$520	$1,200	$550	$1,400	$590	$1,700

*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 proposal's climate-related benefits are associated with methane reductions, but some climate-related impacts are expected from the proposal'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 hourly time scales, 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. Without detailed air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

Recently, 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-CO2 and SC-CH4 estimates discussed above, and required a number of additional assumptions such as baseline mortality rates and mortality response to ozone concentrations. The Sarofim *et al.* (2015) study may have implications for this benefits analysis as it provides a potential approach to estimating the ozone related mortality benefits resulting from the methane reductions expected from this proposed rulemaking. The EPA requests comment on Sarofim *et al.*'s approach to estimating the ozone related mortality benefits of methane emissions reductions, including technical considerations in applying their methodology to this regulatory impact analysis.

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 air quality modeling for this rule needed to quantify the $PM_{2.5}$ benefits associated with reducing VOC emissions. 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.

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), and these estimates can provide useful context for this rulemaking. Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOC, the Laden *et al.* (2006) mortality function (based on the Harvard Six Cities study, a large cohort epidemiology study in the Eastern U.S., an analysis year of 2015, a 3 percent discount rate, and 2006$). 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 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, and 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 reflects the range of epidemiology studies and the range of the urban areas is $300 to $7,500 per ton of VOC reduced (2012$).[37] 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.[38] 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 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 $PM_{2.5}$, 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.

[37] 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.

[38] 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 based on Previous Modeling in 2015 (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**

* 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 the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 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 recently completed 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 well sites, 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, the 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, the 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).[39] After updating the currency year to 2012$, this implies a

[39] 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 $1,070 per ton of VOC reduced. Since EPA conducted the analysis of industrial boilers, the 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). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. 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 42 percent since 1990. However, despite this decline, the 2005 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, 2011d).[40] 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.[41] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. 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 2005 NATA, the EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall

[40] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[41] 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 2005 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. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

cancer risks are formaldehyde and benzene.[42,43] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[44] subchronic,[45] or acute[46] 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 2005 NATA, about three-fourths 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 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-2 and Figure 4-3 depict the 2005 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 double acrolein emissions on a national basis in the EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more

[42] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[43] 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/ttn/atw/nata/roy/page16.html.

[44] 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).

[45] 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).

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

toxic than acetaldehyde.[47] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

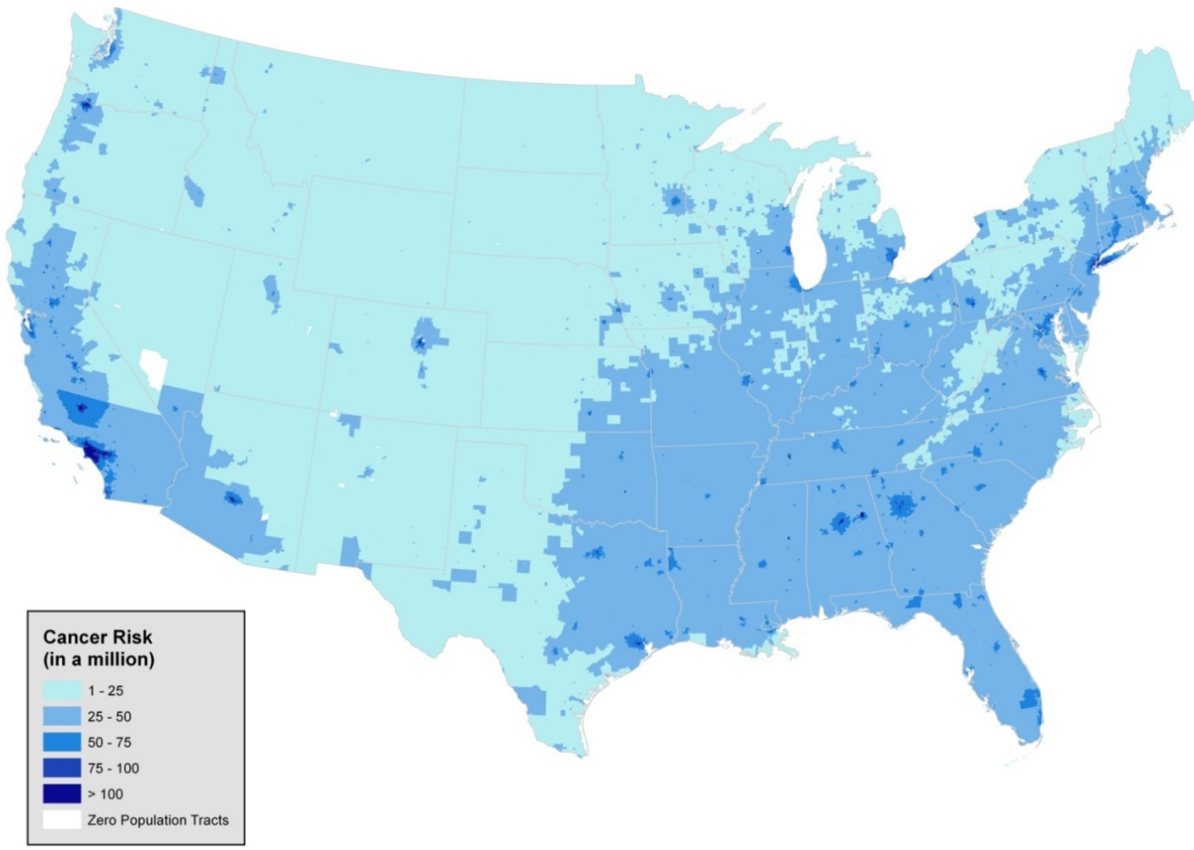

Figure 4-2 2005 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2005 National Toxics Inventory

[47] 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://cfpub.epa.gov/ncea/iris/compare.cfm.

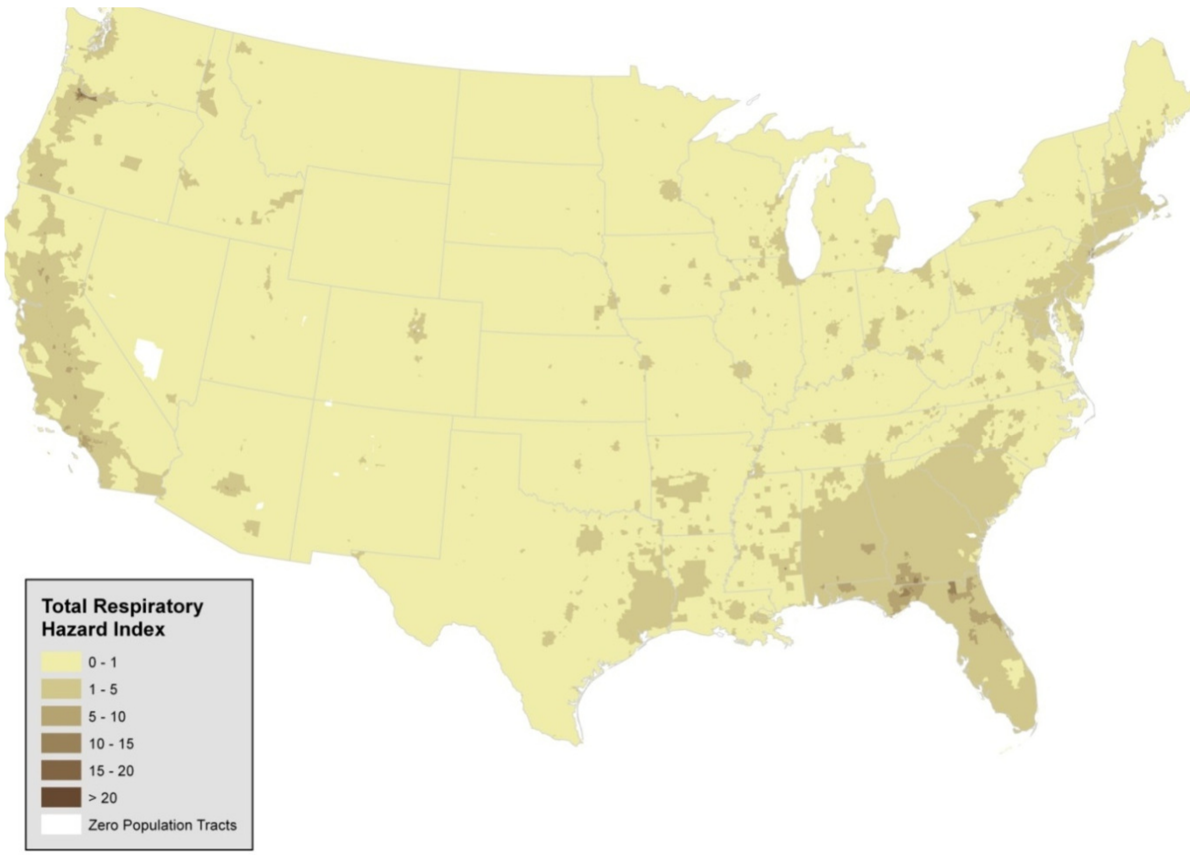

Figure 4-3 2005 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2005 National Toxics Inventory

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, the 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, the 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), the 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, the 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, the 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. The 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 2,500 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.[48,49,50] The 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

[48] 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.

[49] 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.

[50] 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.[51,52] 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.[53,54] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[55,56] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[57,58,59,60] The EPA's IRIS program has not yet evaluated these new data.

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

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[51] 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.

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

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

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

[55] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

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

[57] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[58] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, *et al.* (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[59] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., *et al.* (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[60] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

[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>.

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 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

[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.

sulfide has not undergone a complete evaluation and determination under the 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 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

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[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.

[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.

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 number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[70] The 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

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[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.

[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.

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 the 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 4-7 shows the estimated secondary emissions impacts. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant impacts is small.

[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

Table 4-6 Secondary Air Pollutant Impacts (short tons per year)

	2020				
Emissions Category	**CO_2**	**NO_X**	**PM**	**CO**	**THC**
Total Hydraulically Fractured and Re-fractured Oil Well Completions	580,000	300	10	1,600	620
Fugitive Emissions	*minimal*	*minimal*	*minimal*	*minimal*	*minimal*
Pneumatic Pumps	24,000	12	0	66	25
Pneumatic Controllers	0	0	0	0	0
Compressors	550	0	0	2	1
Total 2020	**610,000**	**310**	**10**	**1,700**	**640**
	2025				
Emissions Category	**CO_2**	**NO_X**	**PM**	**CO**	**THC**
Total Hydraulically Fractured and Re-fractured Oil Well Completions	610,000	310	11	1,700	640
Fugitive Emissions	*minimal*	*minimal*	*minimal*	*minimal*	*minimal*
Pneumatic Pumps	140,000	72	0	400	150
Pneumatic Controllers	0	0	0	0	0
Compressors	3,300	2	0	9	3
Total in 2025	**750,000**	**380**	**11**	**2,100**	**790**

The secondary emision impacts for regulatory options are equal across the options. This result holds because the only requirements varied across the options is the coverage (low and high impact cases of the proposed Option 2) or frequency (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. We are not estimating the monetized disbenefits of the secondary emissions of CO_2 because much of the methane that would have been released in the absence of the flare would have eventually oxidized into CO_2 in the atmosphere. Note that the CO_2 produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC-CH_4.

However, the EPA does recognize that 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 from oxidized methane would be less than the estimated impact of CO_2 released immediately from flaring, which would imply a small disbenefit associated with flaring. Assuming an average methane oxidation period of 8.7 years, consistent with the lifetime used in IPCC AR4, the disbenefits associated with destroying one metric ton of methane and releasing the CO_2

emissions in 2020 instead of being released in the future via the methane oxidation process is estimated to be \$5 to \$25 per metric ton CH_4 depending on the SC-CO_2 value or 0.7 percent to 0.9 percent of the SC-CH_4 estimates per metric ton for 2020. The analogous estimates for 2025 are \$7 to \$34 per metric ton CH_4 or 0.8 percent to 1.0 percent of the SC-CH_4 estimates per metric ton for 2025.[73] While the EPA is not accounting for the CO_2 disbenefits at this time, we request comment on the appropriateness of the monetization of such impacts using the SC-CO_2 and aspects of the calculation.

Table 4-7 provides a summary of the direct and secondary emissions changes. Based on this summary and analysis above, the net impact of both the direct and secondary impacts of this proposal 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		**Proposed Option 2 (Low)**		**Proposed Option 2 (High)**		**Option 3**	
	Pollutant	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**
Change in Direct Emissions	Methane	170,000	340,000	170,000	340,000	180,000	400,000	190,000	470,000
	VOC	120,000	170,000	120,000	170,000	120,000	180,000	130,000	200,000
	HAP	310	1,900	310	1,900	400	2,500	510	3,200
Change in Secondary Emissions	CO_2	610,000	750,000	610,000	750,000	610,000	750,000	610,000	750,000
	NOx	310	380	310	380	310	380	310	380
	PM	10	11	10	11	10	11	10	11
	CO	1,700	2,100	1,700	2,100	1,700	2,100	1,700	2,100
	THC	640	790	640	790	640	790	640	790
Net Change in CO_2 Eq. Emissions	CO_2 Eq. (million short tons)	4.2	8.5	4.2	8.5	4.4	9.9	4.7	12
	CO_2 Eq. (million metric tons)	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11

Note: Totals may not sum due to independent rounding.

[73] To calculate the disbenefits associated the complete destruction of a ton of CH_4 through flaring, EPA took the difference between the SC-CO_2 at the time of the flaring and in 8.7 years and discounted that value to the time of the flaring 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. The value of the SC-CO_2 8.7 years after flaring was estimated by linearly interpolating between the annual SC-CO_2 estimates reported in the TSD and inflated to 2012 dollars.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under section 3(f)(1) Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. Tables 6-1 through 6-4 shows the results of the cost and benefits analysis for this proposed rule.

5.2 Paperwork Reduction Act

The Office of Management and Budget (OMB) has previously approved the information collection activities contained in 40 CFR part 60, subpart OOOO under the PRA and has assigned OMB control number 2060-0673 and ICR number 2437.01; a summary can be found at 77 F.R. 49537. The information collection requirements in today's proposed rule titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (40 CFR part 60 subpart OOOOa) have been submitted for approval to the OMB under the PRA. The ICR document prepared by the EPA has been assigned EPA ICR Number 2523.01. You can find a copy of the ICR in the docket for this rule, and is briefly summarized below.

The information to be collected for the proposed 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 state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in 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 train 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 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of $3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 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).

5.3 Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 3 of this RIA. The analysis in the IRFA drew upon the same analysis and assumptions as the analyses presented in RIA. The IRFA analysis is presented in its entirely in Section 7.3 of the RIA.

Identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. To identify potentially affected entities under the proposed NSPS, the EPA combined information from industry databases to identify firms drilling and completing wells in 2012, as well as identified their oil and natural gas production levels for that year.

The EPA based the analysis in the IRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions While the IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent a large majority of the estimated compliance costs of the proposed NSPS in 2020 and 2025. Note incorporating impacts from other provisions in this analysis is a limitation and underestimates impacts, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the proposed rule in its entirety.

We projected the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in this RIA. This approach assumes that no other firms perform potentially affected activities and firms performing oil and natural gas activities in 2012 will continue to do so in 2020 and 2025. While likely true for many firms, this will not be the case for all firms.

For some firms, we estimated their 2012 sales levels by multiplying 2012 oil and natural gas production levels reported in an industry database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the $4/Mcf for natural gas. 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".

For projected 2020 and 2025 potentially affected activities, we allocated compliance costs across entities based upon the costs estimated in the TSD and used in the RIA. The RIA and IRFA also estimates the potential implications of the proposed exclusion for low producing sites from the fugitive emission requirements. Fewer sites in the program due to this exclusion will likely lead to lower costs and emissions.

The analysis indicates about 1,200 to 2,100 small entities may be subject to the requirements for hydraulically fractured and re-fractured oil well completions and fugitive emissions requirements at well sites. The low end of this range reflects an estimate of how many entities might be excluded as a result of the low production fugitive emissions exemption. Also, the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS. Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the case without the entities that might be excluded from fugitive emissions requirements as a result of the low production exemption.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 3 of the RIA.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

5.4 Unfunded Mandates Reform Act

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

5.5 Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. These final rules primarily affect private industry and would not impose significant economic costs on state or local governments.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The majority of the units impacted by this rulemaking on tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or a tribal government is given delegated authority to enforce the rulemaking.

The EPA consulted with tribal officials under the "EPA Policy on Consultation and Coordination with Indian Tribes" early in the process of developing this regulation to permit them to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process. We provided an update on the methane strategy on the January 29, 2015, NTAA and EPA Air

Policy call. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

GHGs including methane contribute to climate change and are emitted in significant quantities by the oil and gas sector. The EPA believes that the GHG emission reductions resulting from implementation of these final guidelines will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section V of this preamble.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies will prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as “significant energy actions.” Section 4(b) of Executive Order 13211 defines “significant energy actions” as any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This action is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates. We estimate that natural gas and crude oil production levels remains essentially unchanged in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of this proposed rule, please see Section 7 of this RIA.

5.9 National Technology Transfer and Advancement Act (NTTAA) and 1 C.F.R. part 51

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 21, 22, and 25A of 40 C.F.R. part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22. All potential standards were reviewed to determine the practicality of the VCS for this rule. In this rule, the EPA is proposing to include in a final EPA rule regulatory text for 40 CFR part 60, subpart OOOOa that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is proposing to incorporate by reference ANSI/ASME PTC 19-10–1981, Flue and Exhaust Gas Analyses (Part 10) to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The EPA has determined this because the rulemaking increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations. The EPA has provided meaningful participation opportunities for minority, low-income, indigenous populations and tribes during the pre-proposal period by conducting community calls and webinars. Additionally, the EPA will conduct outreach for communities after the rulemaking is finalized.

6 COMPARISON OF BENEFITS AND COSTS

Tables 6-1 though Table 6-3 present the summary of the benefits, costs, and net benefits for the NSPS across regulatory options. Table 6-4 provides a summary of the direct and secondary emissions changes for each regulatory option.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$200 million	$470 million
Total Costs[2]	$150 million	$310 million
Net Benefits[3]	$43 million	$160 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC reduced	Health effects of $PM_{2.5}$ and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 310 tons of HAP reduced	Health effects of HAP exposure from 1,900 tons of HAP reduced
	Health effects of ozone exposure from 170,000 tons of methane	Health effects of ozone exposure from 340,000 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 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 $89 million to $530 million in 2020 and $220 million to $1,200 million in 2025 for the proposed option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 million metric tons in 2020 and 7.7 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[3] Estimates may not sum due to independent rounding.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Proposed Option) in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$200 to $210 million	$460 to $550 million
Total Costs[2]	$150 to $170 million	$320 to $420 million
Net Benefits[3]	$35 to $42 million	$120 to $150 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC reduced	Health effects of $PM_{2.5}$ and ozone exposure from 170,000 to 180,000 tons of VOC reduced
	Health effects of HAP exposure from 310 to 400 tons of HAP reduced	Health effects of HAP exposure from 1,900 to 2,500 tons of HAP reduced
	Health effects of ozone exposure from 170,000 to 180,000 tons of methane	Health effects of ozone exposure from 340,000 to 400,000 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 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 $88 million to $550 million in 2020 and $220 million to $1,400 million in 2025 for the proposed option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[3] Estimates may not sum due to independent rounding.

Table 6-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012$)

	2020	2025
Total Monetized Benefits[1]	$220 million	$640 million
Total Costs[2]	$210 million	$680 million
Net Benefits[3]	$7.6 million	-$35 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of $PM_{2.5}$ and ozone exposure from 130,000 tons of VOC reduced	Health effects of $PM_{2.5}$ and ozone exposure from 200,000 tons of VOC reduced
	Health effects of HAP exposure from 510 tons of HAP reduced	Health effects of HAP exposure from 3,200 tons of HAP reduced
	Health effects of ozone exposure from 190,000 tons of methane	Health effects of ozone exposure from 470,000 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 $99 million to $590 million in 2020 and $300 million to $1,700 million in 2025 for this more stringent option, as shown in Section 4.3. The CO_2-equivalent (CO_2 Eq.) methane emission reductions are 4.2 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the proposed 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. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.
[3] Estimates may not sum due to independent rounding.

Table 6-4 Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted)

		Option 1		Proposed Option 2 (Low)		Proposed Option 2 (High)		Option 3	
	Pollutant	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**	**2020**	**2025**
Change in Direct Emissions	Methane	170,000	340,000	170,000	340,000	180,000	400,000	190,000	470,000
	VOC	120,000	170,000	120,000	170,000	120,000	180,000	130,000	200,000
	HAP	310	1,900	310	1,900	400	2,500	510	3,200
Change in Secondary Emissions	CO_2	610,000	750,000	610,000	750,000	610,000	750,000	610,000	750,000
	NOx	310	380	310	380	310	380	310	380
	PM	10	11	10	11	10	11	10	11
	CO	1,700	2,100	1,700	2,100	1,700	2,100	1,700	2,100
	THC	640	790	640	790	640	790	640	790
Net Change in CO_2 Eq. Emissions	CO_2 Eq. (million short tons)	4.2	8.5	4.2	8.5	4.4	9.9	4.7	12
	CO_2 Eq. (million metric tons)	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11

Note: Totals may not sum due to independent rounding.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

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

- Energy System Impacts
- Initial Regulatory Flexibility Analysis
- Employment Impacts

7.2 Energy System Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. 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. We evaluate whether and to what extent the increased production costs imposed by the proposed rule might alter the mix of fuels consumed at a national level. The EPA only modeled the energy system impacts of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

A brief conceptual discussion about our energy system 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 example, the analysis for the proposed rule shows that performing reduced emissions completions on hydraulically-fractured oil wells contributes about 75 percent of the natural gas captured by emissions controls in 2020 and about 32 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to capture about 18 percent of the natural gas captured by emissions controls in 2020 and about 52 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. Depending on the situation, the gas captured by a REC is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

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.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of 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 expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

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 < 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 model 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 2014.[74] The RIA baseline is consistent with that of the Annual Energy Outlook 2014 which is used extensively in Section 2 in the Industry Profile.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the proposed 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, 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

[74] Assumptions for the 2014 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/>.

extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the proposed 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 proposed rule.

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.

7.2.2.1 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. Additional NSPS 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 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.

One caveat in introducing new cost requirements into the model is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the required capital. A caveat to this is that the estimated unit-level capital costs of controls that are newly required at a national-level as a result of the regulation may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 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 expected 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.

Based on the baseline projections of successful completions in 2020, we used 35,404 new crude oil wells and 8,456 new natural gas wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point by the appropriate number of expected new 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 (Table 1).

Hydraulically fractured oil wells 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 (70 percent).

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 7-1 Per Well Costs for Environmental Controls Entered into NEMS (2012$)

Emissions Sources/Points	Wells Applied To in NEMS	Annualized Cost per Unit (2012$)	Per New Well Costs Applied in NEMS (2012$)	Gas Recovery per Unit (Mcf)	Per New Well Gas Recovery Applied in NEMS (Mcf)
Well Completions					
Hydraulically Fractured Oil Well Completions	New Hydraulically Fractured Oil Wells	$17,182 / $3723	$7,067	0	0
Fugitive Emissions					
Oil Production Well Sites	New Oil Wells	$2,144	$1,072	38	19
Natural Gas Production Well Sites	New Gas Wells	$2,144	$1,072	158	79
Gathering and Boosting Stations	New Gas Wells	$14,028	$430	1,222	37
Transmission Stations	New Gas Wells	$13,879	$10	1,938	1
Storage Facilities	New Gas Wells	$21,049	$37	5,107	9
Reciprocating Compressors					
Transmission Stations	New Gas Wells	$1,748	$5	1,122	3
Storage Facilities	New Gas Wells	$2,077	$11	1,130	6
Centrifugal Compressors					
Storage Facilities	New Gas Wells	$114,146	$13	0	0
Pneumatic Controllers -					
Transmission and Storage Stations	New Gas Wells	$25	$1	0	0
Pneumatic Pumps					
Well Sites	New Wells	$285	$19	0	0
Reporting and Recordkeeping	New Wells	$1,381,023*	$31	0	0

*Note: reporting and recordkeeping costs are assumed to be equally allocated across all new wells.

7.2.2.2 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 an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

We enter the increased natural gas recovery into NEMS on a per-well basis for new natural gas wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 7-1). For this analysis, however, we were unable to incorporate the natural gas recovery from performing RECs on hydraulically fractured oil well completions or from other emissions control activities at oil well sites. We hope to make this modification in the RIA for the final rule.

7.2.3 Energy System Impacts

As mentioned earlier, 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.[75] 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 proposal. We also presented impacts over the 2020 to 2025 time 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 off-shore production is not affected by the proposed NSPS and the bulk of the proposed rule's impacts are expected in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 7-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

[75] The EPA only modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

Table 7-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

	2012	Projection, 2020 Baseline	Projection, 2020 NSPS	Projection, 2025 Baseline	Projection, 2025 NSPS	Projection, 2020-25 Baseline	Projection, 2020-25 NSPS
Successful Wells Drilled							
Natural Gas	10,965	20,298	20,299	24,727	24,800	142,764	142,638
Crude Oil	26,517	24,660	24,660	27,648	27,638	155,201	155,202
Total	**37,482**	**44,959**	**44,959**	**52,375**	**52,438**	**297,965**	**297,840**
% Change in Successful Wells Drilled from Baseline							
Natural Gas			0.00%		0.30%		-0.09%
Crude Oil			0.00%		-0.04%		0.00%
Total			**0.00%**		**0.12%**		**-0.04%**

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

Results show that the proposed NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, but increases for natural gas wells in 2025, while decreasing for crude oil wells in 2025. The increase in natural gas well drilling in 2025 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 time periods. Natural gas well drilling over the 2020 to 2025 period decreases but about 120 wells total. Crude oil drilling, over the same six-year, period remains at the same levels.

Table 7-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the proposed NSPS.

Table 7-3 Annual Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

	2012	Projection, 2020 Baseline	Projection, 2020 NSPS	Projection, 2025 Baseline	Projection, 2025 NSPS	Projection, 2020-25 Baseline	Projection, 2020-25 NSPS
Domestic Production							
Natural Gas (trillion cubic feet)	22.075	26.577	26.576	28.931	28.927	167.585	167.576
Crude Oil (million barrels/day)	4.599	7.234	7.234	7.064	7.062	7.174	7.173
Natural Gas			0.00%		-0.01%		-0.01%
Crude Oil			0.00%		-0.03%		-0.01%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

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. Again, production levels Drilling remains essentially unchanged in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Total production over the 2020 to 2025 is also estimated to decline for natural gas (by about 9 bcf or 0.01 percent) and crude oil (by about 1,000 barrels per day or about 0.01 percent)

Note this analysis estimates no increase in domestic natural gas production, despite some environmental controls anticipated to be used in response to the proposed rule capture natural gas that would otherwise be emitted (8.2 bcf in 2020 and 19 bcf in 2025). There are two sources for this difference. First, we were unable to incorporate into the model the natural gas recovery from performing RECs on hydraulically fractured oil well completions or from other emissions control activities at oil well sites. Second, 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 7-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 7-4 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)	2.562	4.458	4.458	5.064	5.071	4.670	4.673
Crude Oil (2012$ per barrel)	94.938	92.913	92.913	104.889	104.887	98.932	98.931
% Change in Lower 48 Average Wellhead Price from Baseline							
Natural Gas			0.00%		0.14%		0.06%
Crude Oil			0.00%		0.00%		0.00%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. The production weighted average price over the 2020 to 2025 period is estimated to increase by $0.003 per Mcf or about 0.06 percent. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. This is likely result of both the relatively small scale of the costs of the new compliance requirements, as well as the fact that oil prices are more a function of global prices that are natural gas prices.

Meanwhile, as shown in Table 7-5, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent), 2025 (by about 3 bcf or 0.09 percent), and across the 2020 to 2025 period (by about 4 bcf total or about 0.03 percent). Crude oil imports are estimated to not change in 2020, increase by about 1,000 barrels per day (or 0.02 percent) in 2025 or by about 2,000 barrels per day (or about 0.02 percent) on average during the 2020 to 2025 time period.

Table 7-5 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)	1.515	-1.901	-1.900	-3.211	-3.208	-15.371	-15.367
Crude Oil (million barrels/day)	8.432	5.781	5.781	6.004	6.005	5.914	5.916
% Change in Net Imports							
Natural Gas			-0.05%		-0.09%		-0.03%
Crude Oil			0.00%		0.02%		0.02%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

7.3 Initial 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. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the proposed 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. An IRFA describes the economic impact of the proposed rule on small entities and any significant alternatives to the proposed rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact.

7.3.1 Reasons why Action is Being Considered

This action proposes to amend 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 EPA is including requirements for methane emissions in this proposal because methane is a greenhouse gas (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. The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category.

7.3.2 Statement of Objectives and Legal Basis for Proposed Rules

The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are proposing both methane and VOC standards for several emission sources not currently covered by the NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, and pneumatic pumps). In addition, we are proposing methane standards for certain emission sources that are currently regulated for VOC (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the source category, the current NSPS regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The proposed amendents would establish methane standards for these equipment across the source category and extend the current VOC standards to the remaining unregulated equipment. Lastly, amendments to the current NSPS are being proposed that improve implementation of several aspects of the current standards. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue "standards of performance" for new sources in such source categories. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, and identify within each source category the facilities for which standards of performance would be established.

CAA Section 111(a)(1) defines "a standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated." This definition makes clear that the standard of performance must be based on controls that constitute "the best system of emission reduction… adequately demonstrated". The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as "new source performance standards." The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

7.3.3 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.[76] The EPA identified the size of ultimate parent entities by using the Small Business Administration (SBA) size threshold guidelines.[77] The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as follows:

Table 7-6 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	-	500
211112	Natural Gas Liquid Extraction	-	500
213111	Drilling Oil and Gas Wells	-	500
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

[76] 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.

[77] U.S. Small Business Administration (SBA). 2014. Small Business Size Standards. Effective as of July 14, 2014. See: http://www.sba.gov/sites/default/files/Size_Standards_Table.pdf.

potentially affected new or modified source at the firm level. Because of these limitations, we based the analysis in this IRFA on impacts estimates for the proposed 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) 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.[78] 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.[79] 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 IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent about 97 percent and 94 percent of the estimated compliance costs of the proposed NSPS in 2020 and 2025, respectively (Table 7-7). Note 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 proposed rule in its entirety.

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

[79] 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.

Table 7-7 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	$120,000,000	71%	$120,000,000	29%
Fugitive Emissions at Well-sites[1]	$43,000,000	25%	$270,000,000	64%
Other Sources	$5,800,000	3%	$30,000,000	7%
Total Annualized Costs of Proposed NSPS	$170,000,000	100%	$420,000,000	100%

[1] Estimates for fugitive emissions requirements based on "high impact" case.
Note: sums may not total due to independent rounding.

To identify potentially affected entities under the proposed NSPS, the EPA combined ownership information from the DrillingInfo dataset with information drawn from the Hoover's Inc. online platform, which includes information about companies NAICS codes, employee counts, and sales information.[80] Note that this analysis assumes that the firms performing potentially affected activities are also the firms performing activities in the future under the proposed 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 7-8 for a summary of results of this matching exercise.

[80] 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.

Table 7-8 No. of Completions in 2012 by Preliminary Firm Size

Firm Size Performing Well Completions	No. of Firms	Number of Completions, 2012: Hydraulically Fractured or Re-fractured Oil Wells	All Completions
Small	1,000	3,300	12,000
Not Small	67	10,000	21,000
Unknown	1,100	750	6,000
Total	**2,200**	**14,000**	**39,000**

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 slightly lower than totals included in impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

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 7-9.

Table 7-9 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	1,100 to 2,200	4,000	7,800 to 18,000
Not Small	66 to 67	10,000	15,000 to 21,000
Total	**1,200 to 2,200**	**14,000**	**23,000 to 39,000**

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 slightly lower than totals included in impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

The proposed NSPS provides an exclusion for low producing sites from the fugitive emissions requirements.[81] A low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.[82] While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this IRFA, like the RIA, presents a "low" impact case and

[81] In the preamble to the proposed rule, EPA is soliciting comment on excluding low production sites from the fugitive emissions program.
[82] Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

"high" impact case for fugitive emissions requirements at well sites. The low impact case excludes an estimate low production sites, based on the first month of production data from wells newly completed or modified in 2012.The high impact case includes these well sites. Table 7-9 presents the number of wells completed in the base year of 2012, where the range of wells under the fugitive emissions requirements reflects the range of the low and high impact cases. Note that while the number of firms potentially affected goes down substantially, the low production exclusion from fugitive emissions requirements does not affect the number of affected oil well completions.

7.3.4 Compliance Cost Impact Estimates

7.3.4.1 Methodology for Estimating 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 IRFA are based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in this RIA. These growth rates are consistent with the drilling activity in the 2014 Annual Energy Outlook. These growth rates are applied to the 2012 base year estimates for each firm in the database. Table 7-10 and Table 7-11 present future year estimates of incrementally affected new and modified sources, in the low and high impact cases, respectively.

Table 7-10 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size, Low Impact Fugitive Emissions Case

	No. of Incrementally Affected Sources, 2020			No. of Incrementally Affected Sources, 2025		
Firm Size Performing Well Completions	**Hydraulically Fractured or Re-fractured Oil Wells**	**Gas Well Sites**	**Oil Wells Sites**	**Hydraulically Fractured or Re-fractured Oil Wells**	**Gas Well Sites**	**Oil Wells Sites**
Small	4,100	980	3,400	4,200	6,900	20,000
Not Small	11,000	2,800	5,900	11,000	20,000	35,000
Total	**15,100**	**3,780**	**9,300**	**15,200**	**26,900**	**55,000**

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

Table 7-11 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size, High Impact Fugitive Emissions Case

	No. of Incrementally Affected Sources, 2020			No. of Incrementally Affected Sources, 2025		
Firm Size Performing Well Completions	**Hydraulically Fractured or Re-fractured Oil Wells**	**Gas Well Sites**	**Oil Wells Sites**	**Hydraulically Fractured or Re-fractured Oil Wells**	**Gas Well Sites**	**Oil Wells Sites**
Small	4,100	1,900	7,900	4,200	13,000	48,000
Not Small	11,000	3,600	8,700	11,000	25,000	52,000
Total	**15,100**	**5,500**	**16,600**	**15,200**	**38,000**	**100,000**

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 IRFA 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/completions and completions 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 7-12 shows the distribution of compliance costs estimates across firm size, year, and whether the low production exemption is in place.

Table 7-12 Distribution of Estimated Compliance Costs[1] across Firm Size Classes

	Annualized Compliance Costs (2012$) Low Impact Case			Annualized Compliance Costs (2012$) High Impact Case		
Firm Size	**No. of Firms**	**2020**	**2025**	**No. of Firms**	**2020**	**2025**
Small	1,100	43,000,000	88,000,000	2,200	54,000,000	160,000,000
Not Small	66	100,000,000	190,000,000	67	110,000,000	240,000,000
Total	**1,200**	**150,000,000**	**280,000,000**	**2,200**	**170,000,000**	**390,000,000**

[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 7.1.3, 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 IRFA 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.

7.3.4.2 Results

This section presents results of the cost-to-sales ratio analysis for both the primary scenario and the low oil price scenario. In addition, we present both scenarios for the low and high impact cases with respect to the low production exemption from the well site fugitive emissions requirements.

[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 $4.94/Mcf in the reference case and $4.35/Mcf in the low oil price case. Rounding down to $4/Mcf would likely under-estimated 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. Rounding down to $4/Mcf would likely under-estimated sales.

Table 7-13 Compliance Costs-to-Sales[1] Ratios (Fugitive Emissions Requirements Low Impact Case) across Firm Size Classes for Primary Scenario and Low Oil Price Scenario[2]

	2020 (Primary Scenario)		2020 (Low Oil Price Scenario)	
	No. of Small Entities	**% of Small Entities**	**No. of Small Entities**	**% of Small Entities**
No. of Small Entities	1,200	-	1,200	-
Greater than 1 percent	66	6%	77	7%
Greater than 3 percent	22	2%	25	2%

	2025 (Primary Scenario)		2025 (Low Oil Price Scenario)	
	No. of Small Entities	**% of Small Entities**	**No. of Small Entities**	**% of Small Entities**
No. of Small Entities	1,200	-	1,200	-
Greater than 1 percent	130	11%	160	13%
Greater than 3 percent	44	4%	53	5%

[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.

Table 7-14 Compliance Costs-to-Sales[1] Ratios (Fugitive Emissions Requirements Low Impact Case) across Firm Size Classes for Primary Scenario and Low Oil Price Scenario[2]

	2020 (Primary Scenario)		2020 (Low Oil Price Scenario)	
	No. of Small Entities	**% of Small Entities**	**No. of Small Entities**	**% of Small Entities**
No. of Small Entities	2,100	-	2,100	-
Greater than 1 percent	270	13%	320	15%
Greater than 3 percent	120	6%	140	7%

	2025 (Primary Scenario)		2025 (Low Oil Price Scenario)	
	No. of Small Entities	**% of Small Entities**	**No. of Small Entities**	**% of Small Entities**
No. of Small Entities	2,100	-	2,100	-
Greater than 1 percent	710	33%	800	38%
Greater than 3 percent	370	17%	410	20%

[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 7.1.3, 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.

Comparing Table 7-13 with Table 7-14, about 900 fewer small entities are estimated to be affected by the examined provision in the low impact fugitive emissions requirements case.

Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the high impact to low impact case without the exemption in place by approximately two-thirds. The percent impacted by greater than 3 percent is about double the percent affected by greater than 1 percent for each year of analysis in the primary and in the low oil price scenarios. Meanwhile, impacts greater than 1 percent and 3 percent increase in the low oil price scenarios, as would be expected. Also as expected the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS.

7.3.5 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 limitation here.

- Because of data limitations, the analysis presented in the IRFA 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 proposed NSPS, the omission of the cost requirements 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 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.

7.3.6 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the proposed 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 state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in 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 train 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 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of $3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 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).

7.3.7 Related Federal Rules

The New Source Performance Standards (NSPS) issued in 2012 are currently reducing VOC emissions from several sources in the oil and natural gas industry In addition to the 2012

NSPS, there are two National Emission Standards for Hazardous Air Pollutants (NESHAP) rules that apply to certain equipment and processes in the oil and natural gas sector. These rules, listed below, address air toxics, primarily benzene, toluene, ethylbenzene and xylenes (collectively referred to as BTEX) and n-hexane. These two rules, which were updated concurrently with the 2012 NSPS, were promulgated under section 112 of the Clean Air Act and are codified in 40 CFR Part 63:

- Subpart HH – Crude Oil and Natural Gas Production (including processing); and
- Subpart HHH – Natural Gas Transmission and Storage.

Additionally, 40 CFR Part 98 Subpart W is a greenhouse gas reporting requirement that applies to petroleum and natural gas systems. Owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year from process operations, stationary combustion, miscellaneous use of carbonates, and other source categories are required to report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators are required to collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

7.3.8 Regulatory Flexibility Alternatives

The Panel agrees that the EPA should explore regulatory alternatives and provide flexibility where appropriate. This flexibility can lessen impacts to small entities as well as entities not classified as small.

7.3.8.1 Oil Well Exemptions

SERs encouraged the EPA to exempt stripper wells, low pressure oil wells, and any well that requires artificial lift. SERs recommended that the EPA establish an overall applicability threshold based on production, emissions, well depth, well type (horizontal), well pressure, formation, or revenue to limit potential impact of future regulations on small entities.

The SERs offered several threshold alternatives to be applied to the oil well completion requirements which would significantly reduce compliance costs and burden to small entities that the SERs asserted would not affect gas recovery benefits. Some of these comments are described below. Advocacy believes the EPA had a greater opportunity to advance the discussion by evaluating these alternatives through analysis of the available data. Advocacy further believes that there is enough information to conduct analysis of alternatives now. Advocacy notes that there are several types of thresholds that could be explored by the EPA, such as average production of nearby wells (by oil field, reservoir, or basin), well length or depth, and gas and water pressure characteristics. Advocacy encourages the EPA to do so in the future, in advance of proposal, to facilitate more informed and productive comments from the public which will lead to a better rulemaking.

The EPA has production and well characteristic data on thousands of oil wells through DrillingInfo, which aggregates all well data in the U.S. reported by operators to state agencies. In this database, the EPA could develop thresholds to target geographical areas or well characteristics with greater gas recovery potential than areas or characteristics where costs imposed would achieve little to no benefit. Advocacy believes the EPA should examine the data in DrillingInfo and the studies identified in the White paper for potential alternatives that minimize small entity costs, while achieving significant methane emission benefits. For example, Advocacy performed its own preliminary analysis of the DrillingInfo data, which led us to recommend a production threshold (see below). Advocacy believes the EPA also should consider the peer review and public comments on the white paper and reassess the size and diversity of the oil well completions in a more comprehensive fashion. Advocacy believes the EPA should have provided additional analysis since the publication of the white paper.

The EPA believes that it has reasonably analyzed the available data for this draft proposed rule, and sufficiently documented this analysis through the rule, the technical support document (TSD), and the SBREFA process. However, the EPA notes information gaps and has requested additional data and information through the public comment process.

Gas to Oil Ratio

Advocacy is concerned that the EPA estimate of ten tons of methane reduction per event for oil well completions may be significantly overestimated, based on its analysis of the 2012 Drilling Info database and SER comments. The 2012 analysis includes hydraulically fractured oil well completions with GORs between 300 and 100,000, whereas the 2011 analysis was limited to GORs up to 12,500.

The Panel recommends that the EPA continue analyzing current data, and assess the alternatives mentioned by SERs. In an effort to contribute to the panel process, Advocacy analyzed the EPA data provided. Advocacy found that geographical patterns and well characteristics exist in the data to suggest common sense thresholds. While a 300 gas to oil ratio (GOR) threshold provides some relief for small entities, it is problematic because GOR is not known at time of fracturing when a completion takes place. Advocacy further recommends that the EPA develop a scheme based on the well characteristics of nearby wells in the basin or reservoir to provide an estimate for the GOR parameter. However, the location of the well, and the drill direction are known parameters that could be used. In concert with these other considerations, Advocacy recommends the EPA consider a GOR cutoff closer to 900, as one SER suggested.

The EPA believes that a gas-to-oil ratio (GOR) of 300 scf of gas per barrel of oil produced is an appropriate threshold for facilities to be subject to the well completion provisions of the NSPS. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance[85]. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. The EPA is soliciting comment on whether a GOR of 300 is the appropriate applicability threshold. Additionally, the EPA understands that GOR is not known at the time of well completion, and is soliciting comment on whether the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well.

Low Production Wells

When mapping average daily associated gas of 90 Mcf or above (isolating stripper wells) using county level data, Advocacy found that most (85%) of these greater gas recovery oil well

[85] On February 24, 2015, API submitted a comment to the EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.

completions occur in about a third of the counties analyzed. Advocacy contends that there are potentially large areas that could be exempted from this requirement without forgoing significant methane emission reduction, or at least phased in to allow time to design proper data collection. For example, PIOGA comments report an average gas volume of only 74 MCFD in Pennsylvania stripper oil wells in contrast to Pennsylvania stripper gas wells averaging 532 MCFD.

The EPA understands that low production wells have inherently low emissions from well completions and many are owned and operated by small businesses. However, the EPA recognizes that identification of these wells prior to completion events is difficult, especially considering that drilling of a low production well may be unintentional and may be infrequent, but production may nevertheless proceed due to economic reasons. The EPA is soliciting comment and information on emissions associated with low production wells, characteristics of these wells and supporting information that would help owners/operators and enforcement personnel identify these wells prior to completion.

Because of these preliminary findings about low production and a lack of evidence that there will be sufficient gas recovery, the Panel recommends that the EPA further analyze and consider exempting low production wells (with an average daily production of less than 15 barrel equivalents) from a REC or combustion requirement during oil well completions.

Vertical Wells

According to a SER comment, vertical wells lack sufficient wellhead pressure or quantity of gas to be separated during completion. Advocacy recommends that since the white papers laid the foundation to the materials prepared for the Panel, the EPA should revisit the information learned through this process, especially as it relates to the specific characteristics of vertical wells. Therefore, as a regulatory alternative, Advocacy recommends the EPA consider exempting vertical wells from oil well completion requirements.

The EPA clarifies that both the 2014 white paper analysis of oil well completions and DrillingInfo data analysis include vertical wells that are hydraulically fractured. However, the EPA understands that there are certain physical well characteristics that may inhibit the operation of a separator, and notes that the rule does not require RECs where their use is not feasible.

However, the EPA has not seen sufficient data to support the characterization that a separator will not be able to function for all or the majority of vertical wells that are hydraulically fractured. However, the EPA recommends soliciting comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional).

Low Pressure Oil Wells

Advocacy recommends that "low pressure wells" should be categorically exempt and could be based on a threshold sales line/gathering line of approximately 250 psi or a simple water gradient formula of 0.465 psi/foot. The emissions associated with these types of wells are so low that even if a separator can be operated for some short period of time, the value of gas does not exceed the cost associated with bringing equipment to the site. As the SERs indicated, these oil completion requirements can be very costly on small firms, particularly with respect to small production wells. The expected gas recovery benefits from oil well completions are expected to be a small fraction of the benefits obtained by the gas wells under the current version of the NSPS rule.

The EPA is aware that oil wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC. In the 2012 NSPS the EPA did not require low pressure gas wells to perform REC, but operators were required to control those well completions using combustion. However, the EPA recommends soliciting comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional). The EPA defines low pressure wells as a well with reservoir pressure and true vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter. The EPA recommends soliciting comment on whether this definition is appropriate for low pressure oil wells.

Substitution of Combustion over Green Completion / REC Requirements

Advocacy recommends that the EPA substitute flaring for the green completion requirement (REC), in addition to the consideration of thresholds. This alternative is much more cost-effective, and particularly important for small firms to have a lower cost alternative that achieves a 95% reduction. The PIOGA comments also stated that the use of RECs would adversely impact the productivity and longevity of the stripper oil wells. Alternatively, the EPA could require larger firms to perform the RECs, while allowing smaller firms (using a firm revenue cutoff or other small business size indicator) to combust the remaining gas.

The EPA recommends that RECs be implemented on oil wells, except where their use is not feasible (e.g., technically infeasible for a separator to function, availability of gathering lines). Compared to combustion alone, the EPA believes that the combination of REC and combustion will maximize the recovery of natural resources and minimize venting to the atmosphere. However, the EPA notes that although the flaring in lieu of RECs may be less costly, flaring contributes secondary environmental impacts, nuisance impacts to nearby communities and complicates compliance for owners/operators.

Phase – In for Oil Well Completion Requirements

The Panel recommends that the EPA consider phasing in the well completion requirement over a period of years. The Panel agrees that the EPA solicit comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule in the event of potential shortage of REC equipment and, if not, how a phase in could be structured. The Panel agrees that a phased in approach could be structured to provide for control of the potentially highest emitting wells first, with other wells being included at a later date. The Panel recommends that the EPA solicit comment on whether GOR of the well and production level of the well should be bases for the phasing of requirements for RECs, and if so, what an appropriate threshold for phase-in should be.

7.3.8.2 Fugitives - Leak Detection Methods

SERs encouraged the EPA to allow a variety of leak detection technologies, including Method 21, AVO, and soap testing. The EPA asserts that use of OGI can reduce the amount of time necessary to conduct fugitive emissions monitoring since multiple fugitive emissions components can be surveyed simultaneously, reducing the cost of identifying fugitive emissions compared to alternative leak detection technologies that require a manual screening of each fugitive emissions component. Advocacy recommends the EPA propose Method 21 or OGI as allowable alternatives. The EPA contends that while Method 21 is lacking because it does not allow the detection of malfunctioning equipment that may not be the focus of the survey, and it is not as cost-effective as OGI, the Panel recommends the EPA solicits comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold. The EPA notes that the proposed rule would allow the use either OGI or Method 21 for resurvey because the resurvey would focus solely on ensuring repairs resolved the leak at the individual component.

7.3.8.3 Fugitives – Survey Frequency

SERs recommended leak surveys be conducted no more than once per year. Advocacy has questions about the costs of repair and the emission reductions that be achieved through increased survey frequency which Advocacy believes the EPA was unable to address satisfactorily. Advocacy urges the EPA to improve the record basis for its emission reduction estimates and the cost of repairs for Method 21 and OGI, in order to permit more informed comment on the alternatives. Advocacy believes the EPA was unable to adequately explain the basis for the different repair costs vs. frequency for Method 21 and OGI[86], or the basis for the 40/60/80% emission reductions based on increasing survey frequency from annual to quarterly.[87]

The EPA determined that semiannual monitoring will result in identification and repair of significant fugitive emissions from components, and that using OGI, an operator can survey multiple fugitive emissions components simultaneously reducing the cost of identifying fugitive emissions. Additionally, if fugitive emissions are detected at less than one percent of the fugitive

[6]At this time, the EPA shows annual repair costs that increase linearly with survey frequency for OGI, but are static for Method 21. For Method 21, the EPA applied the same repair costs whether the frequency was annual, semiannual or quarterly. For OGI, EPA used double the repair costs for semiannual, and four times the repair costs for quarterly. Advocacy believes this could lead to a bias in an evaluation of one method vs. the other.

[87] Advocacy was also disappointed that EPA was unable to share with the SERs more information that would have help the SERs formulate their recommendations (including some of the issues addressed above). The EPA believes the background documents created for the SERs were thorough and accurate, and transparently presented the data and data sources used in the analysis for the proposed rule. The documents are additionally available for public review in the docket for the proposed rule.

emission components at a well site during two consecutive semiannual monitoring surveys, the proposed rule allows for the monitoring survey frequency for that well site to be reduced to annually. Advocacy had no information upon which to base a recommendation related to the proportion of leaking components, but supports analysis of such an approach. Advocacy also recommends that the EPA provide more analysis and factual foundation for the record to allow commenters to provide more informed advice.

The Panel agrees that the EPA should solicit comment on an alternate proposal option based on an initial annual survey frequency. The Panel recommends the EPA solicit comment on the appropriateness of semiannual monitoring frequency and the proposed provisions for increasing and decreasing the monitoring frequency.

7.3.8.4 Fugitive Emissions at Well Sites

The Panel recommends not requiring fugitive emission surveys at well production sites, unless there are potentially significant sources of emissions, such as storage tanks. The Panel further agrees that well sites with low production wells (i.e., a well with an average daily production of 15 barrel equivalents or less) should not require fugitive emission surveys.

7.3.8.5 Fugitive Emissions at Production and Processing Sites, and Compressor Stations at Transmission and Storage Sites

Under Subpart W, gas production and processing sites and compressor stations at transmission and storage sites are required to annually monitor for fugitive emissions and to quantify such emissions. The only missing regulatory component to be considered is to add a requirement to repair detected leaks as appropriate. This is already covered by the May 2015 INGAA Directed Inspection and Maintenance voluntary Program for Transmission and Storage Compressor Stations. The EPA is already considering this program[88] in its recent request for comment on the voluntary methane reduction program for the oil and gas sector. Advocacy recommends that the EPA retain the annual requirement, as Advocacy believes this requirement is entirely duplicative of a fugitives survey requirement, and consider the specific repair

[88] US EPA. Natural Gas STAR Methane Challenge Program: Proposed Framework, slide 17 states, "EPA has received, and is considering, a proposal to structure BMP coverage of natural gas transmission and storage compressor stations as a Directed Inspection and Maintenance Program."

requirements for repair identification and repair delay in the DI&M voluntary program as the components of a mandatory program. Furthermore, the EPA's most recent evaluation of the survey cost-effectiveness shows that annual surveys are more cost-effective than semi-annual surveys. Therefore, the Panel recommends the EPA propose options based on semi-annual and annual monitoring. Advocacy recommends that the EPA should also consider allowing each facility to tailor the specific program to site-specific considerations, rather than apply the same requirements uniformly to each plant. The EPA recognizes that Subpart W serves as an emissions inventory, while this rule's intent is to minimize pollution. The EPA believes that the additional survey with semiannual OGI monitoring provides additional leak detection, and cost-effective emission reductions. The EPA recognizes that fugitive emissions may be underestimated based on emerging studies and will continue to evaluate these studies. The Panel recommends the EPA propose an alternate option based on an initial annual frequency for well sites. The Panel recommends that the EPA continue to consider the INGAA DI&M recommendations for leak repairs in the rulemaking.

7.3.8.6 Well Site Compressors

SERs encouraged the EPA to exempt well site compressors as they are typically rental units and have irregular service time, and regulation could be cost prohibitive. The Panel agrees that emissions from well site compressors were extremely low and that cost of control of these compressors would not be reasonable. The Panel recommends that the EPA maintain the exemption for well site compressors.

7.3.8.7 Pneumatic Pumps

SERs encouraged the EPA to exempt pneumatic pumps if controls were not already in place. The Panel agrees that combustion controls should only be required if a control is required for another source. The Panel recommends the EPA exempt pneumatic pumps without a control device already located on site.

7.3.8.8 Reciprocating Compressors

The Panel supports the EPA proposal to require replacement of rod packing every 26,000 hours or 3 years in lieu of monitoring hours. The Panel also supports the further consideration of the alternative developed in the Natural Gas Star Program for condition-based maintenance.

Advocacy recommends the EPA should carefully study the INGAA recommendations for condition-based maintenance for rod packing as an alternative to maintaining or replacing rod packing on a prescribed schedule.[89]

The EPA recommends that the draft proposed rule retain the rod packing replacement options and the option to route the rod packing emissions to a process through a closed vent system under negative pressure.

7.3.8.9 Centrifugal Compressors

Advocacy recommends that the EPA reconsider the requirement of requiring capture and combustion of gas emissions from wet seal compressors whose emissions don't differ that much from dry seal compressors, according to INGAA. Advocacy is concerned that requiring combustion at compressor stations would prove to be unpopular with the surrounding neighborhood. This requirement would convert an otherwise unobtrusive structure in the neighborhood into a constant source of combustion and a source of air pollution.

The EPA recommends retaining the requirement for a 95% emissions reduction from wet seal compressors, which can be achieved by capturing and routing the emissions utilizing a cover and closed vent system to a control device, or routing the captured emissions to a process. The EPA notes that dry seal compressors are not affected facilities in the draft proposed rule because of their inherently low emissions. The EPA also notes that many of these combustors are enclosed and will be innocuous to the surrounding neighborhood. In addition, the gas liberated from the barrier fluid during degassing is very clean natural gas, and the combustor is required under the NSPS to burn cleanly with no visible emissions.

7.3.8.10 Pneumatic Controllers

The Panel agrees with the EPA's recommendation that low-bleed pneumatic controllers be required in place of high-bleed controllers (i.e., natural gas bleed rate not to exceed 6 scfh). The Panel recommends the rule continue to treat low-bleed pneumatic controllers as not affected facilities except at natural gas processing plants, where zero bleed pneumatic controllers are considered BSER.

[89] See INGAA comment on 40 CFR 60 Part OOOO. EPA-HQ-OAR-2010-0505-4104

7.3.8.11 Recordkeeping and Reporting for High Bleed Controllers

The EPA recommends that owners and operators continue to be permitted to use high bleed controllers needed for specific functional purposes, but require recordkeeping to document the justification. The Panel agrees that recordkeeping and reporting requirements should be minimized wherever possible. However, the Panel notes that a recordkeeping and reporting requirement that asks companies to justify and document their need for continuous high bleed devices has caused many companies to reevaluate their need for and change out unnecessary high bleed pneumatic controllers.

7.3.8.12 Liquids Unloading

Based on the information and data available to the EPA during development of the 2012 NSPS, the Panel agrees that control of liquids unloading emissions is not appropriate at this time. However, the EPA believes that the emissions from liquids unloading operations are significant, and so the Panel recommends that the EPA continue to study this issue and solicit information and data supporting demonstrated control technologies or management practices for reducing these emissions.

7.4 Employment Impact Analysis

In addition to addressing the costs and benefits of the proposed rule, the EPA has analyzed the impacts of this rulemaking on employment, which are presented in this section.[90] 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 proposed 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.” [91] A discussion of compliance costs, including reporting and recordkeeping requirements, is included in Section 3of this RIA. This analysis uses detailed engineering information on labor

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[90] The employment analysis in this RIA is part of 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).

[91] 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.

requirements for each of the control strategies identified in this proposed rule in order to estimate partial 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 proposed rule.

7.4.1 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 an impact on overall employment because labor is being shifted from one sector to another. On the other hand, in periods of high unemployment, 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. Currently in most cases there is no scientifically defensible way to generate sufficiently reliable estimates of the employment impacts in these intermediate goods sectors.

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 and both sets of authors tested their models empirically using different methodologies. 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.[92] 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).[93]

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 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

[92] Berman and Bui include over 40 4-digit SIC industries in their sample.

[93] Including the employment effect of exiting plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.

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 employment impacts from this proposed 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 proposed 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.[94] 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 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 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.[95] Once the EPA receives guidance from this panel it will carefully

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

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

consider this input and then decide if and how to proceed on economy-wide modeling of employment impacts of its regulations.

7.4.2 Labor Estimates Associated with Proposed Requirements

Section 2 of the RIA, in Tables 2-17 and 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 2013.[96] 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 2013 peak of 620,000. 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 2013, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2013 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 proposed 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 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 to reduce output negative production externality (i.e., emissions) a firm often has to reduce production, many of the emission controls required by the proposed NSPS will simultaneously increase production and reduce negative externalities. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. 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. To the extent, however, that these

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

rules may require unprofitable investments for some operators, 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 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 either 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 people involved or whether new jobs are created for new employees.

The results of this employment analysis of the proposed NSPS are presented in Tables 7-16 through Table 7-19 for 2020 and 2025 for individual sources regulated under this proposal. Table 7-20 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 proposal, 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 proposed 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 of which are included in the cost estimates presented in Chapter 3.

Table 7-15 presents estimates 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 completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed annually. Because of these reasons, we assume the REC-related labor requirements are annual.

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 7-15 Estimates of Labor Required to Comply with Proposed NSPS for Hydraulically Fractured Oil Well Completions, 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			
Hydraulically Fractured and Re-fractured Oil Well Completions								
Development Oil Wells	Reduced Emission Completion	6,903	0	93	0	644,937	0	310
Wildcat and Delineation Oil Wells	Completion Combustion	7,773	0	9	0	73,289	0	35
Total		**14,676**	**N/A**	**N/A**	**0**	**718,227**	**0**	**345**
					2025			
Hydraulically Fractured and Re-fractured Oil Well Completions								
Development Oil Wells	Reduced Emission Completion	6,901	0	93	0	644,751	0	310
Wildcat and Delineation Oil Wells	Completion Combustion	8,066	0	9	0	76,055	0	37
Total		**14,967**	**N/A**	**N/A**	**0**	**720,806**	**0**	**347**

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 7-16 and Table 7-17 present estimates of labor requirements for the low and the high impacts cases for fugitive emissions. Consistent with the cost estimates for fugitive emissions presented in 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 as proposed. 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 are likely underestimates.

Table 7-16 Estimates of Labor Required to Comply with Proposed NSPS for Fugitive Emissions, Low Impact Case, 2020 and 2025

Emissions Source/	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor (hrs)	Per-unit Annual Labor (hrs)	Total One-Time Labor (hrs)	Total Annual Labor (hrs)	One-time FTE	Annual FTE
					2020			
Well Sites								
Company-level Activities	Semiannual Monitoring/	605	118.0	0.0	71,352	0	34	0
Site-level Activities	Maintenance	13,303	0.0	14.1	0	187,717	0	90
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	259	0.0	108.7	0	28,141	0	14
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	6	0.0	108.7	0	652	0	0
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	15	0.0	212.9	0	3,193	0	2
Total		**13,583**	**N/A**	**N/A**	**104,392**	**219,702**	**50**	**106**
					2025			
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	139,108	5.4	14.1	0	1,962,940	0	944
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	1,554	0.0	108.7	0	168,844	0	81
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	36	0.0	108.7	0	3,911	0	2
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	90	0.0	212.9	0	19,160	0	9
Total		**140,788**	**N/A**	**N/A**	**151,469**	**2,154,855**	**73**	**1,036**

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 7-17 Estimates of Labor Required to Comply with Proposed NSPS for Fugitive Emissions, High Impact Case, 2020 and 2025

Emissions Source/	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor (hrs)	Per-unit Annual Labor (hrs)	Total One-Time Labor (hrs)	Total Annual Labor (hrs)	One-time FTE	Annual FTE
					2020			
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	22,080	0.0	14.1	0	311,569	0	150
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	259	0.0	108.7	0	28,141	0	14
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	6	0.0	108.7	0	652	0	0
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	15	0.0	212.9	0	3,193	0	2
Total		**22,360**	**N/A**	**N/A**	**151,469**	**343,555**	**73**	**165**
					2025			
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	139,108	5.4	14.1	0	1,962,940	0	944
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	1,554	0.0	108.7	0	168,844	0	81
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	36	0.0	108.7	0	3,911	0	2
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	90	0.0	212.9	0	19,160	0	9
Total		**140,788**	**N/A**	**N/A**	**151,469**	**2,154,855**	**73**	**1,036**

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.

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 proposed NSPS accumulates.

Table 7-18 presents labor requirement estimates for reciprocating and 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 7-18 Estimates of Labor Required to Comply with Proposed 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	67	1	1	67	67	0.0	0.0
Centrifugal	Route to Control	1	355	0	355	0	0.2	0.0
Total		**68**	**N/A**	**N/A**	**422**	**67**	**0.2**	**0.0**
					2025			
Compressors								
Reciprocating	Monitoring and Maintenance	402	1	1	67	402	0.0	0.2
Centrifugal	Route to Control	6	355	0	355	0	0.2	0.0
Total		**408**	**N/A**	**N/A**	**422**	**402**	**0.2**	**0.2**

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 7-19 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 7-19 Estimates of Labor Required to Comply with Proposed 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	210	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	2,962	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
					2025			
Pneumatic Controllers	Emissions Limit	1,260	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	17,772	*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 7-20 presents the labor estimates across all emissions sources. Two main categories contain the majority of the labor requirements for the proposed 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 proposed NSPS is estimated at 73 FTEs in 2020 and in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 530 FTEs in 2020 and 1,400 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 7-20 Estimates of Labor Required to Comply with Proposed 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	15,000	0	720,000	0	350
Fugitive Emissions	14,000 to 22,000	100,000 to 150,000	220,000 to 340,000	50 to 73	110 to 170
Pneumatic Controllers	210	0	0	0	0
Pneumatic Pumps	3,000	N/A	N/A	N/A	N/A
Reciprocating Compressors	67	67	67	0	0
Centrifugal Compressors	1	360	0	0	0
Reporting and Recordkeeping Requirements	All	0	40,000	0	19
Total	**31,000 to 40,000**	**100,000 to 150,000**	**980,000 to 1,100,000**	**50 to 73**	**470 to 530**
			2025		
Hydraulically Fractured and Re-fractured Oil Well Completions	15,000	0	720,000	0	350
Fugitive Emissions	86,000 to 140,000	100,000 to 150,000	1,400,000 to 2,200,000	50 to 73	660 to 1,000
Pneumatic Controllers	1,300	0	0	0	0
Pneumatic Pumps	18,000	N/A	N/A	N/A	N/A
Reciprocating Compressors	400	67	400	0	0
Centrifugal Compressors	6	360	0	0	0
Reporting and Recordkeeping Requirements	All	0	120,000	0	58
Total	**120,000 to 180,000**	**100,000 to 150,000**	**2,200,000 to 3,000,000**	**50 to 73**	**1,100 to 1,400**

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.

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