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

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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this rule amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOC) from Natural Gas Processing Plants, and finalizes the NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this rule addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also finalizes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million annually. EPA estimates the final NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP Amendments are being finalized in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the final NESHAP Amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the final NSPS and NESHAP Amendments. We also estimate potential impacts of the final rules 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 a 7 percent discount rate. This analysis assumes an analysis year of 2015. The final NSPS contains provisions related to reduced emissions completions, pneumatic controllers, and storage vessels that phase-in emissions control requirements over time. As a result of these provisions, 2015 is the first year that the full requirements of the NSPS are in effect. Because of the phase-in provisions of the NSPS, the RIA does not present an accurate assessment of the period between promulgation and the end of 2014, but is accurate for 2015.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically fractured natural gas wells, capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. RECs also recover saleable hydrocarbon condensates that would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS. In the economic impact and energy economy analyses for the NSPS, we present results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emissions reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline.[1] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in Section 3 of this RIA.

[1] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20 year voluntary initiative with participation from 124 natural gas companies operating in the U.S., including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that RECs can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the Agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

Additionally, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary RECs are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation, and serves in part to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are *required* to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

1.2 Summary of Results

1.2.1 NSPS Results

For the final NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The final NSPS is anticipated to prevent significant new emissions, including 190,000 tons of VOC, as well as from 11,000 tons of hazardous air pollutants (HAP) and 1.0 million tons of methane. While we expect that these 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.[2] This is not to imply that there are no benefits of the rules; 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 methane emissions reductions associated with the final NSPS are likely to result in climate co-benefits. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total

[2] 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 for the break-even analysis, 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.

hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons. If the EPA's estimate of voluntary action is not included in the NSPS baseline (only REC under state regulations are assumed to occur absent the NSPS), the emissions reductions achieved by the final NSPS in HAP, methane and VOC are estimated at about 19,000 tons, 1.7 million tons and 290,000 tons, respectively.

- **Engineering Cost Analysis:** EPA estimates the total capital cost of the final NSPS will be $25 million, regardless of baseline assumptions. The estimate of total annualized engineering costs of the final NSPS is $170 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the final NSPS are estimated to be -$15 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. 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 engineering compliance costs of about $43 million, given EPA estimates that 43 billion cubic feet of natural gas will be recovered by implementing the NSPS. If voluntary action is not deducted from the baseline, capital costs for the NSPS under the alternative regulatory baseline are estimated at $25 million, and annualized costs without revenues from product recovery for the NSPS are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million. All estimates are in 2008 dollars.

- **Small Entity Analyses:** For the final NSPS, EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. When revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (96.9 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3.1 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front 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 up-front labor requirement to comply with the final NSPS is estimated at 50 full-time-equivalent employees. The annual labor requirement to comply with final NSPS is estimated at about 570 full-time-equivalent employees. 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 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS in 2015[1]

	Final[4]
Total Monetized Benefits[2]	N/A
Total Costs[3]	-$15 million
Net Benefits	N/A
Non-monetized Benefits[6]	190,000 tons of VOC
	11,000 tons of HAP[5]
	1.0 million tons of methane[5]
	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment
	Vegetation effects
	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; 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.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAP and climate effects are co-benefits.

[6] The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons.

1.2.2 NESHAP Amendments Results

For the final NESHAP Amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The final NESHAP Amendments are anticipated to reduce a significant amount of existing emissions, including 670 tons of HAP, as well as 1,200 tons of VOC and 420 tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAP, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; 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.[3] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are about 8,000 metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the final NESHAP Amendments to be $2.8 million. Total annualized engineering costs, which includes annualized capital costs and operating and maintenance costs, of the final NESHAP Amendments are estimated to be $3.5 million. All estimates are in 2008 dollars.
- **Small Entity Analyses:** For the final NESHAP Amendments, EPA estimates that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none of the 11 (zero percent) are likely to have impacts of greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front 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 up-front labor requirement to comply with the final NESHAP Amendments is estimated at 4 full-time-equivalent employees. The annual labor requirement to comply with final NESHAP Amendments is estimated at about 30 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to identify the specific

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[3] 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 for the break-even analysis, 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.

number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $5,200 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $2,900 per ton or the methane emissions would need to be valued **a**t $8,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NESHAP in 2015[1]

	Final
Total Monetized Benefits[2]	N/A
Total Costs[3]	$3.5 million
Net Benefits	N/A
Non-monetized Benefits[5]	670 tons of HAP
	1,200 tons of VOC[4]
	420 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; 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.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

[5] The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 8,000 metric

tons.

1.2.3 Results of Energy System Impacts Analysis of the NSPS and NESHAP Amendments

The analysis of energy system impacts using NEMS for the final NSPS shows that domestic natural gas production is not likely to change in 2015, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.

1.2.4 Results for Combined Small Entity Analysis for the NSPS and NESHAP Amendments

After considering the economic impact of the combined NSPS and NESHAP Amendments on small entities, EPA certifies this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, EPA performed an additional screening analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP Amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, all 136 small firms (100 percent) in the sample are likely to have impacts of less than 1 percent.

1.3 Summary of NSPS Impacts Changes from the Proposal RIA

This section summarizes major changes from the proposal version of the RIA. These changes were a result of revised assumptions and technical factors, as well as changes in the rule itself from proposal.

- **Revised baseline to include voluntary RECs:** The NSPS analysis used a baseline that accounted for emission controls required by state regulation, but did not include voluntary actions. In the final RIA, to account for emissions reductions and costs arising in the baseline from voluntary implementation of pollution controls, EPA used information on total emissions reductions reported by partners of the EPA Natural Gas STAR. Additionally, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary reduced emission completions (REC) are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation.

- **Changed estimate of number of recompleted natural gas wells:** The NSPS proposal estimated that 12,050 RECs for existing natural gas well recompletions would be required in addition to those already required by state regulations. EPA has reevaluated the assumption based on data submitted to the Agency. Based on this information, EPA has estimated the recompletion frequency to be 1 percent of fractured gas wells per year, rather than 10 percent. More detailed discussion is presented in a technical memorandum on this subject in the docket.[4]
- **Recompletions of existing natural gas wells that are hydraulically refractured:** In the final rule, recompletions of existing natural gas wells that are hydraulically refractured are only subject to the NSPS if emissions from these completions are uncontrolled.
- **New hydraulically fractured natural gas well completions with insufficient pressure to implement REC required to combust completions emissions:** Using the formula estimated to identify hydraulically fractured natural gas well completions that would not have sufficient pressure to perform a REC, approximately 10 percent of well completions would be required to combust emissions rather than implement a REC. More detailed discussion is presented in a technical memorandum on this subject in the docket.[5]
- **Revised natural gas emissions factor for well completions and recompletions of hydraulically fractured wells:** The EPA received several comments regarding the emissions factor selected to calculate whole gas emissions (and the associated VOC emissions) from hydraulically fractured well completions. Comments focused on the data behind the emissions factor, what the emissions factor is intended to represent, and the procedures used to develop the emissions factor from the selected data sets. We reviewed all information received and have decided to retain the data set and the analysis conducted to develop the emissions factor, but rounded from 9,175 Mcf per completion

[4] “Gas Well Refracture Frequency” in U.S. Environmental Protection Agency Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

[5] “NSPS Low Pressure Completion Threshold” in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

to 9,000 Mcf per completion. More detailed discussion is presented in a technical memorandum on this subject in the docket.[6]

- **Changed estimate of REC and completion emission combustion capital costs:** The requirements related to completions of hydraulically fractured natural gas wells (combustion and REC) are essentially one-shot events that typically occur over a few days to a couple of weeks and are generally performed by independent contractors. The emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. Given that we base our REC costs estimates on the average cost for contracting the REC as a service, we expect contractors' operation and maintenance costs, depreciations, and potential salvage value of the equipment to be reflected in the total contracting costs. Because of these factors, we decided to treat the hydraulically fractured natural gas well completion requirements solely as annualized costs, which differed from our analysis at proposal, which equated capital and annualized costs.
- **Removal of compressors and pneumatic devices in the natural gas transmission segment from NSPS:** In the final rule, proposed requirements relating to reciprocating and centrifugal compressors and pneumatic devices in the transmission segment are removed. Given the large number of sources, and the relatively low level of VOCs emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on compressors and pneumatic controllers in the transmission and storage segment. Requirements pertaining to storage vessels in the transmission segment remain.
- **Reporting and recordkeeping costs**: EPA identified several ways to streamline reporting and recordkeeping requirements. As a result, the estimated annual cost of reporting and recordkeeping decreased from $19 million per year to $2.6 million per year.

1.4 Summary of NESHAP Amendments Impacts Changes from the Proposal RIA

The cost and emissions reduction estimates for the NESHAP Amendments are reduced from proposal because proposed provisions related to storage vessels were not finalized from proposal, as well as because of changes to the proposed provisions for small gycol dehydrators. The estimated capital costs of the NESHAP Amendments decreased by about $49 million (from $52 to about $3 million), while estimated total annualized compliance costs decreased by about $12.5 million per year (from $16 to $3.5 million per year) . As a result, estimated HAP reductions decreased by about 710 tons per year from proposal (from 1,380 to 670 tons per year).

[6] "Evaluation of the Emissions factor for Hydraulically Fractured Gas Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

Also, because of changes in emissions limits from proposal, fewer glycol dehydrators are affected, which reduces capital and annualized costs, as well as emissions reductions for these emissions points.

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 business 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 and NESHAP Amendments 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 (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the final NSPS and NESHAP Amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the final NSPS and NESHAP Amendments. 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 U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

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 of the petroleum industry 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^o or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

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

2.2.5 Produced Water

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

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either 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, 2009). 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, 2009). 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 natural gas resource types relevant for this rule include:

- **Shale 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, 2009).

- **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, 2009).

- **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, inferred reserves, undiscovered technically recoverable resources and total technically recoverable resources as of 2007. According to EIA[7], 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.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** 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, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

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

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385.0	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas. While the dry natural gas proved reserves in 2007 were estimated at 237.7 tcf, wet natural gas reserves were estimated at 247.8 tcf. Of this difference, about 9.1 tcf is accounted for by natural gas liquids. Of the 247.8 tcf, 215.1 tcf (about 87 percent) is considered to be wet non-associated natural gas, while 32.7 tcf (about 13 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 2008. 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, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

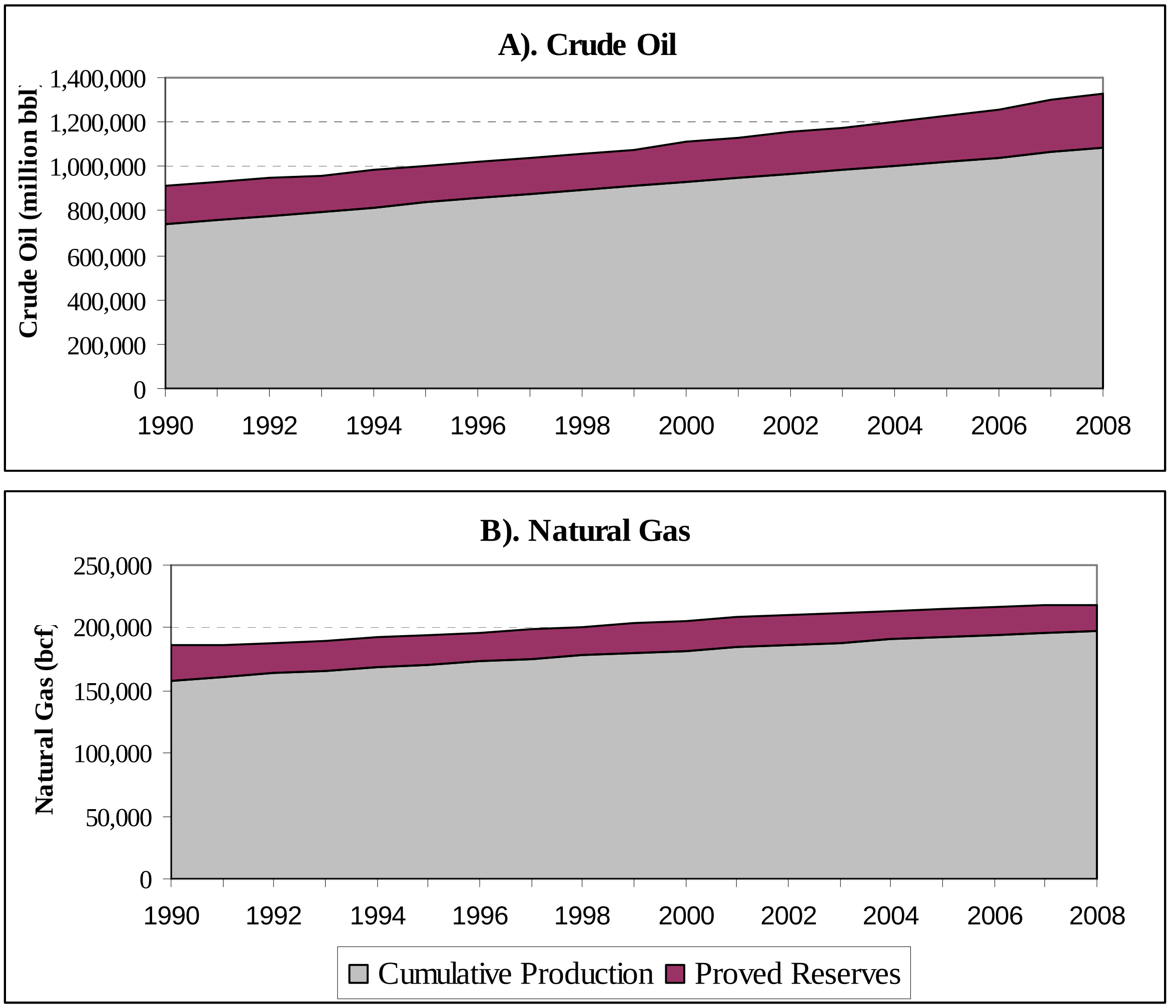

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

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

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also 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. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (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.

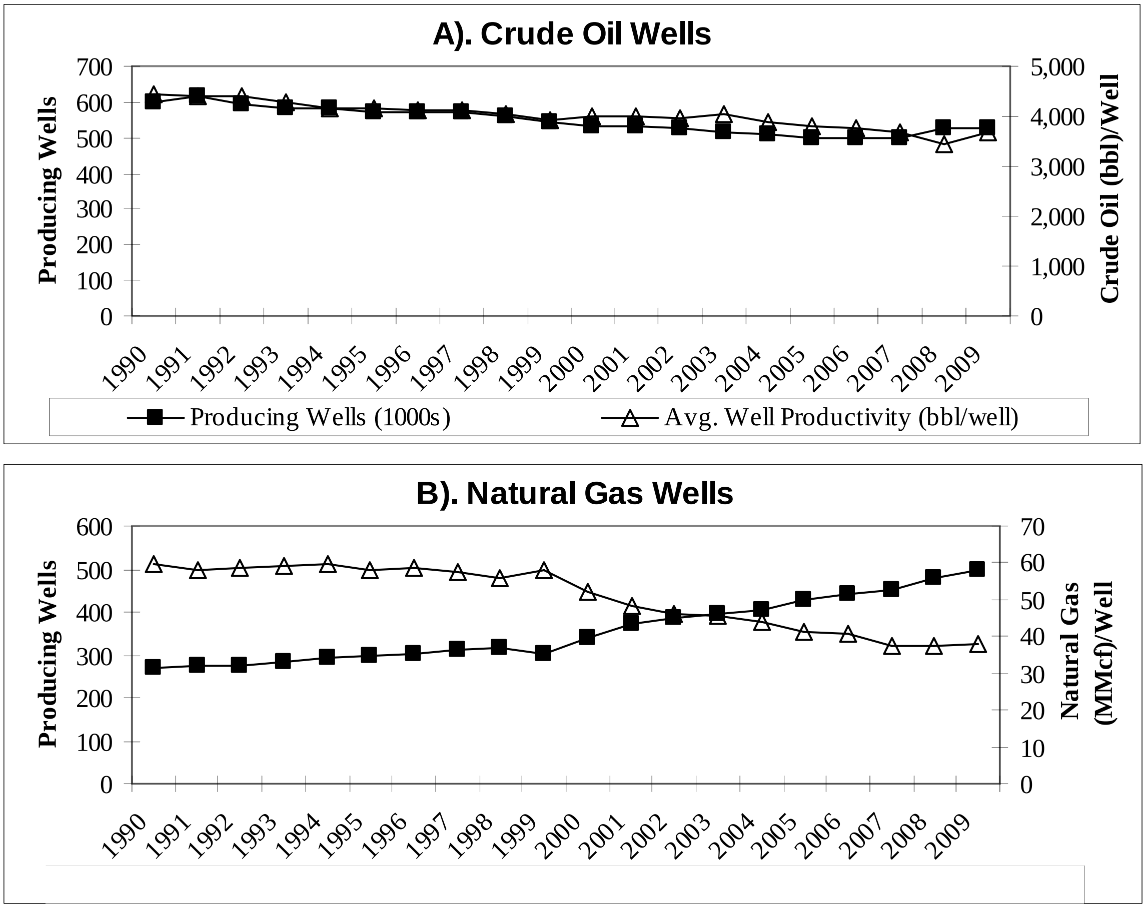

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 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 1990-2009 period. Like crude oil drilling, 2009 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 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, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 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 Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

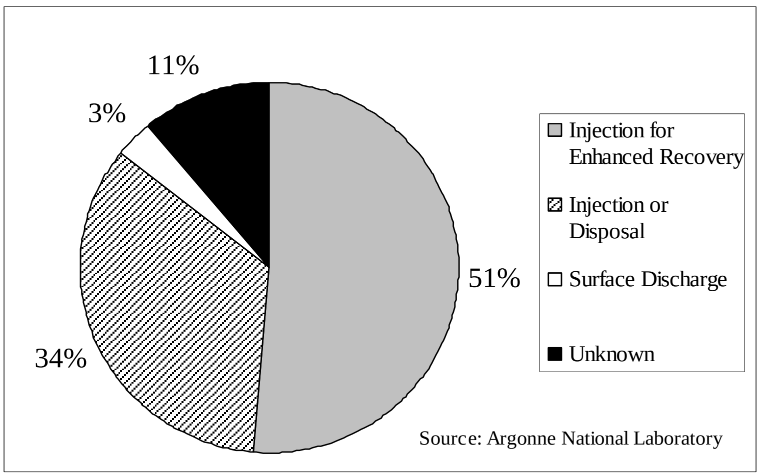

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

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 1990-2008 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, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, 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. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 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 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

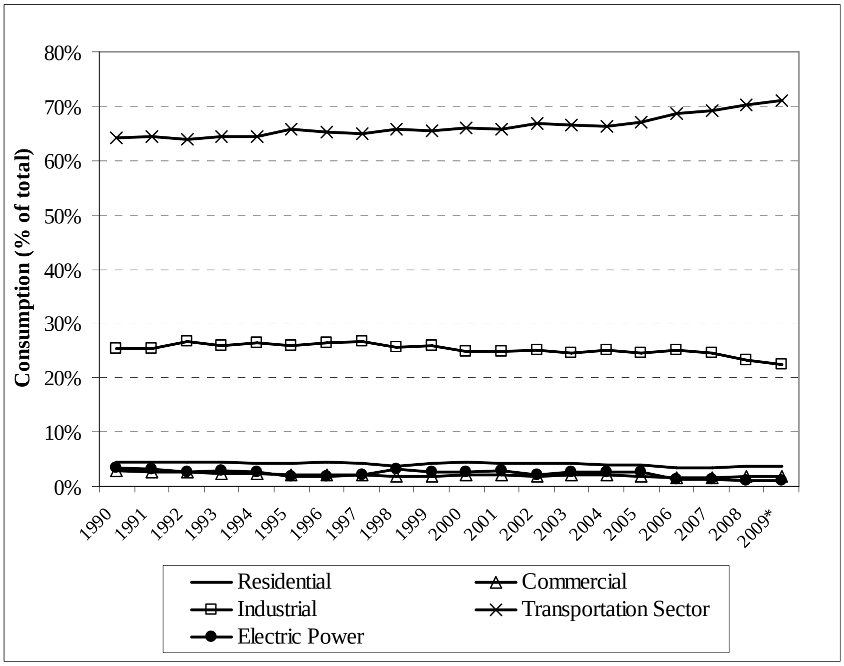

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, 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, 1990-2009

Year	Total (bcf)	Percent of Total: Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

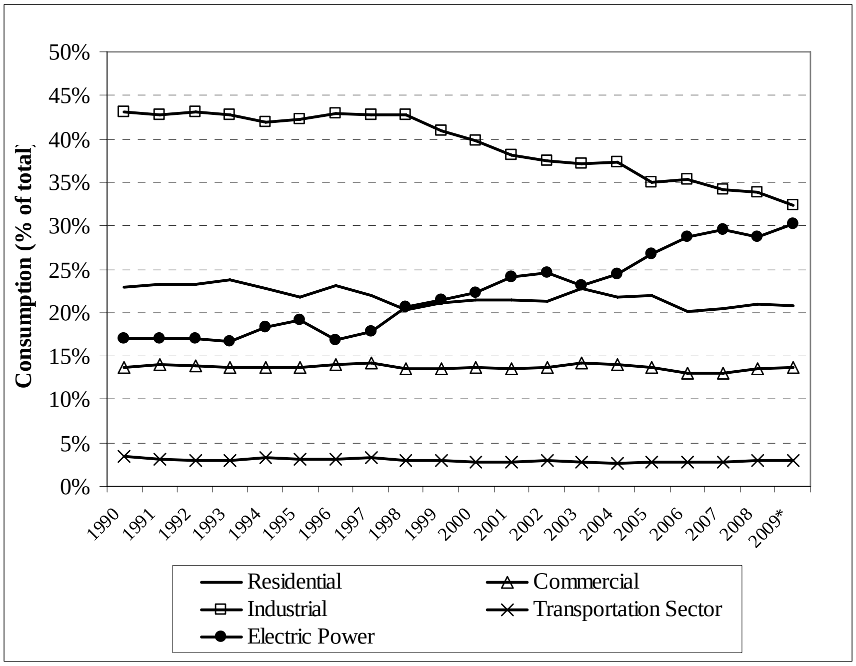

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. 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, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
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	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

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 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the final NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

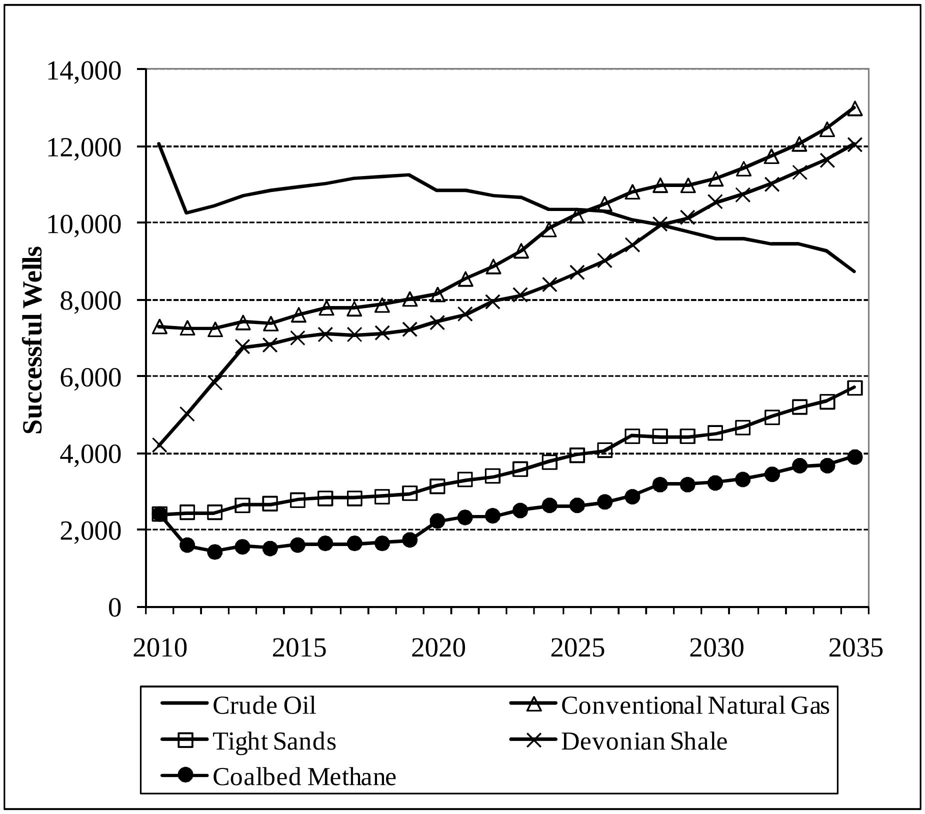

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

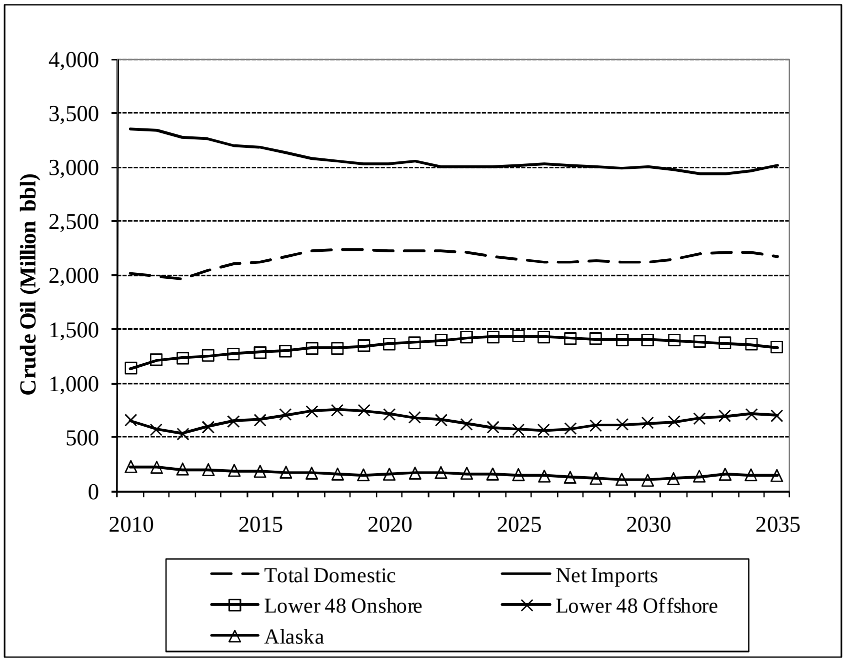

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

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

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

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 2-8).

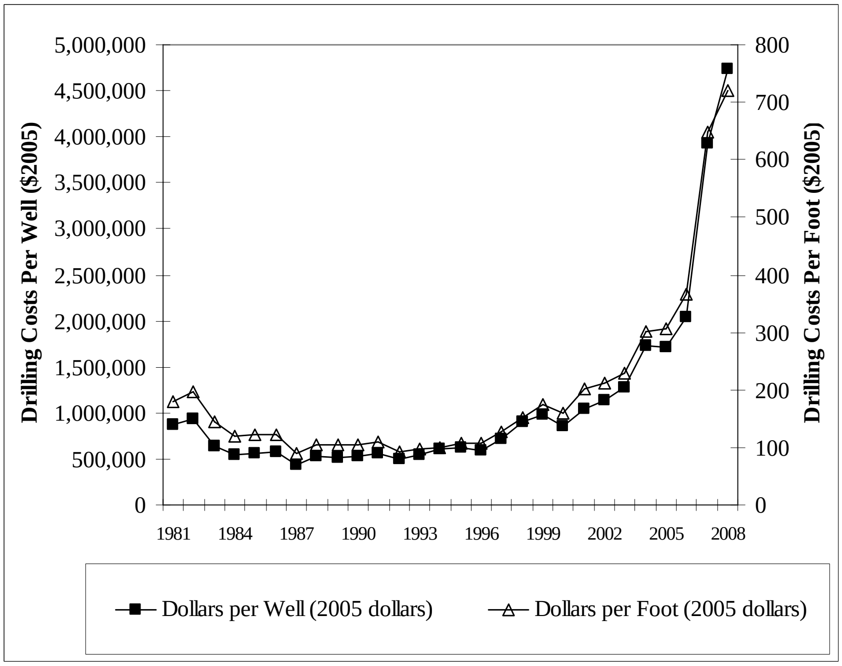

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

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 2-9 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 2008. The costs are reported in 2008 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.

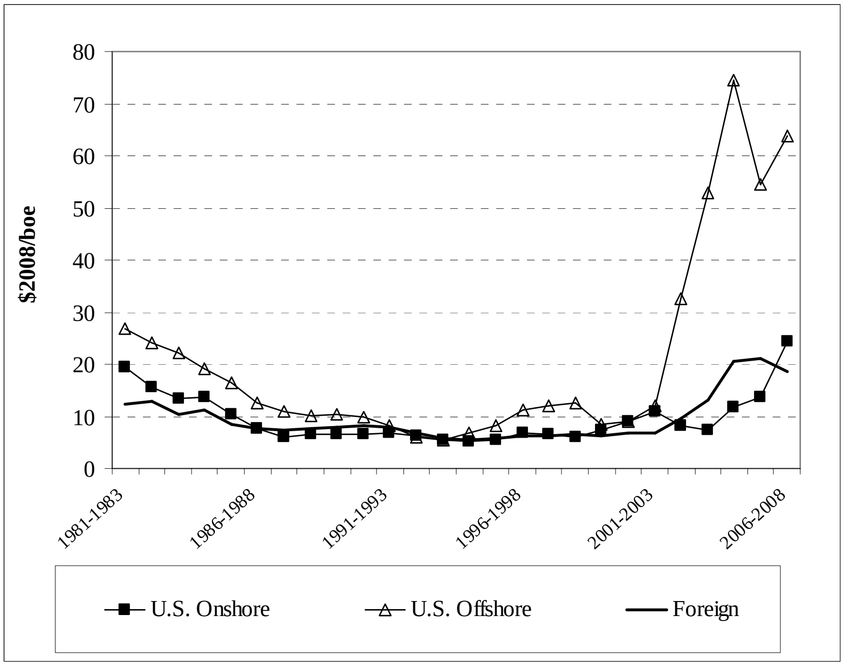

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

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 2-8 and finding costs in Figure 2-9 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 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

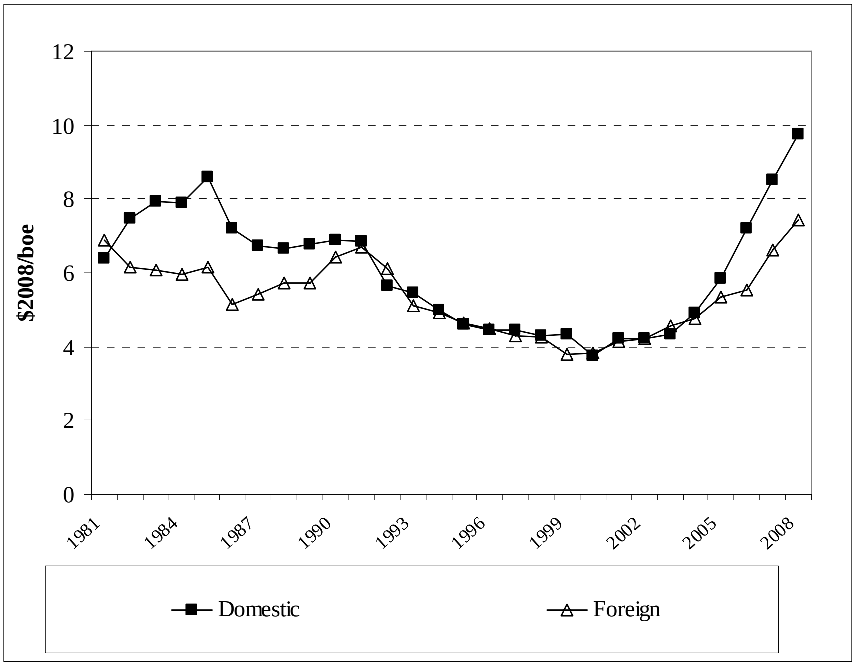

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

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 2008, domestic lifting costs increased sharply, about $6 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 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[8], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

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

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 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.

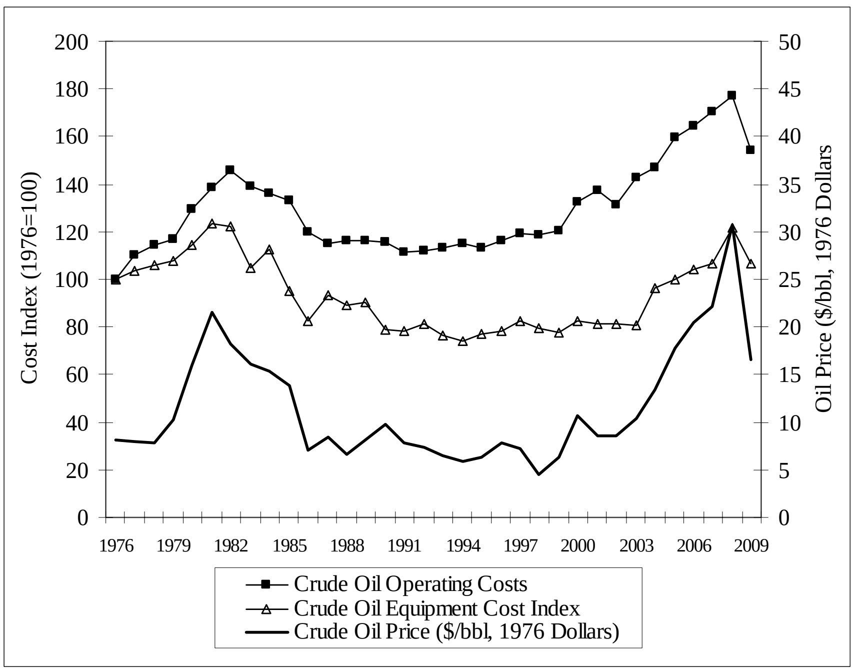

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

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.

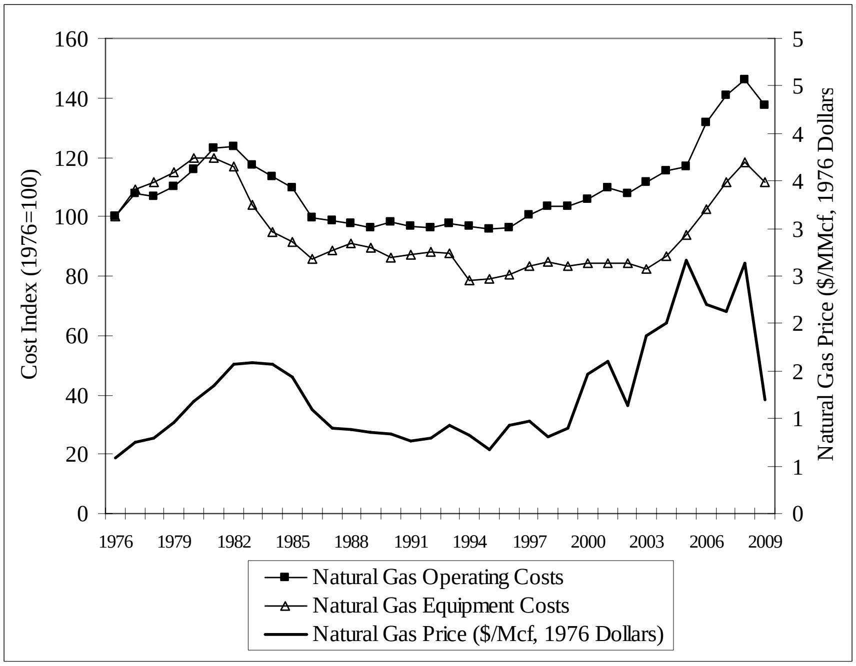

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 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

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

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

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007."
<http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. 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 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. 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, 1990-09

Year	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	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	30,469
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

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 ,
<http://www.bls.gov/cew/>

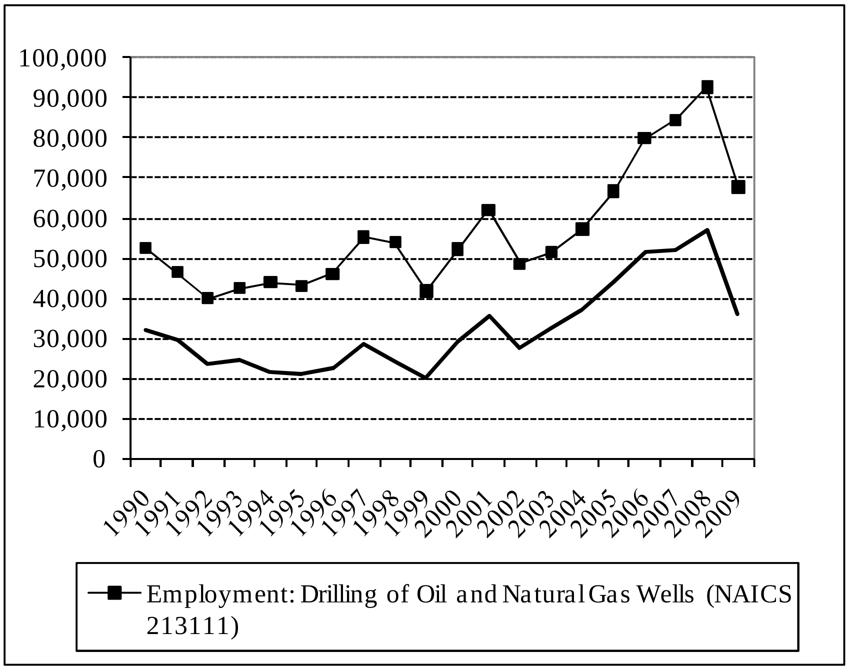

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

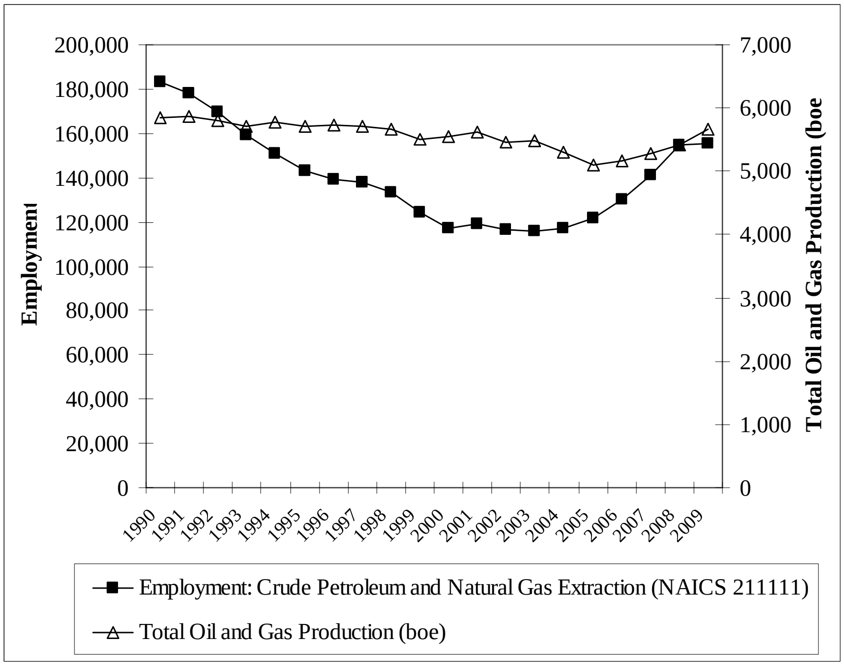

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

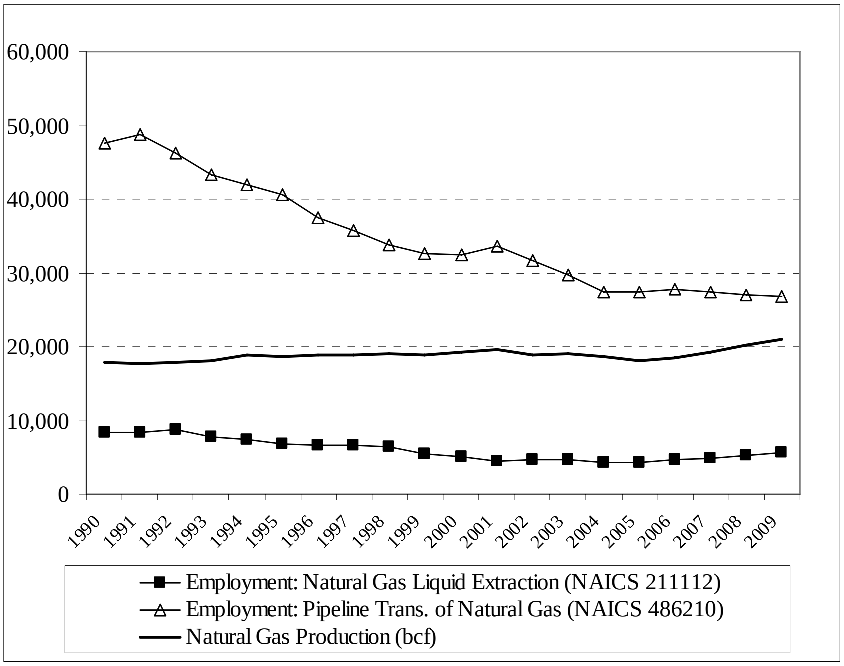

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	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 Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

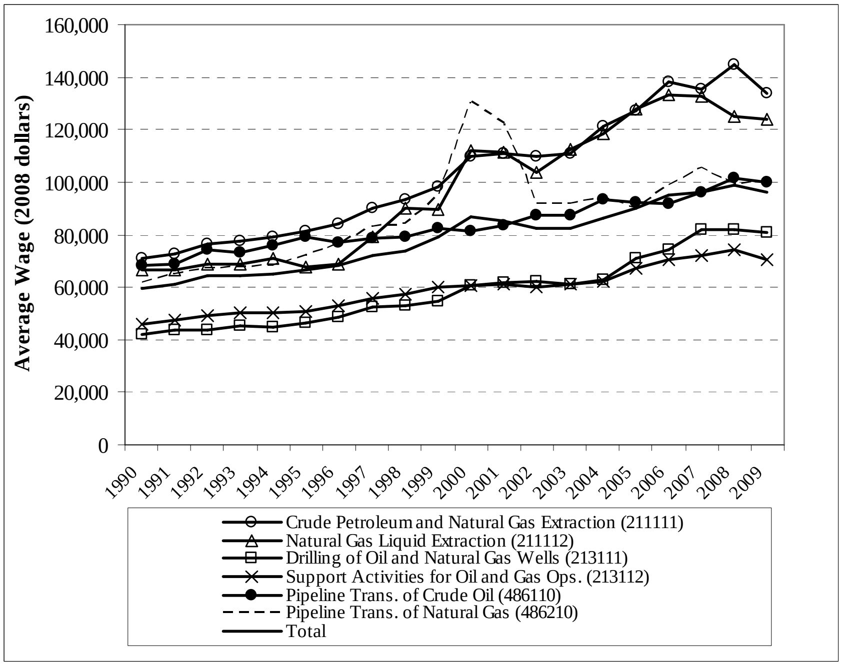

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

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 2010, all 137 public companies are listed.[9] Table 2-19 lists selected

[9] Oil and Gas Journal. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010.

statistics for the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to 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), 2010

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production		U.S. Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

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 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). 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 2009. 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 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. “Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow.” November 1, 2010.

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. This information is used in annual report to Congress, as well as is released to the 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 2008, there are 27 companies in the FRS[10] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). 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 as well. 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 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

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

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.

[10] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., 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., WRB Refining LLC, and XTO Energy, Inc.

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

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

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

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 2008 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) 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, about 13 percent of the total paid to U.S. authorities.

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

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income 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

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

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 section includes three sets of discussions for both the final NSPS and NESHAP Amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the final NSPS and NESHAP Amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, employment, and small business analyses.

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 final rules. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources that are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (132,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 1.87 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this analysis includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

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 proposal Technical Support Document (TSD) and Background Supplemental Technical Support Document for the Final New Source Performance Standards, which are published in the Docket. Technical memos that also discuss revisions to the proposal TSD are noted in the relevant sections.

Centrifugal and reciprocating compressors [11]**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of

[11] "Centrifugal Compressor Impacts" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks: Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated the NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers: Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement 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. Gas-driven pneumatic controllers are typically characterized as “high-bleed” or “low-bleed”, where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels[12]: Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These

[12] “Update to Technical Support Document for Proposed Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution- Equipment Leaks” in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from production wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emissions will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions: In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the 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. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving natural gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate natural gas completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than natural gas completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled natural gas well completion emissions for a hydraulically fractured natural gas well are about 23 tons of VOC, where emissions for a conventional natural gas well completion are around 0.1 ton of VOC. Our data indicate that hydraulically fractured natural gas wells have higher emissions but we believe some natural gas wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured natural gas wells could have lower emissions than our data show.

Reduced emission completions, which are sometimes referred to as “green completions” or “flareless completions,” use equipment at the well site to capture and treat natural gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion at a natural gas well may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions of natural gas wells will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of natural gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the final NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader’s understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos, which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[13]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either (1) to a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's

[13] Memorandum from Brown, H., EC/R Incorporated to Moore, B., and Nizich, G., EPA/OAQPS/SPPD/FIG. Impacts of Final MACT Standards for Glycol Dehydration Units – Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories. April 17, 2012.

emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

3.2.2 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 in order to comply with the final NSPS and NESHAP Amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in a series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in the analysis supporting the proposed and final rules. The final NSPS contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. The NSPS also requires a subset of natural gas wells that are recompleted using hydraulic fracturing to implement a REC and emissions combustion. The NSPS requires emissions reductions from reciprocating compressors at gathering and boosting stations and processing plants. The NSPS also requires emissions reductions from centrifugal compressors at processing plants. Finally, the NSPS requires emissions reductions from pneumatic controllers at oil and gas production facilities and reductions from storage vessels that emit at least six tons of VOC per year.

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

Emissions Sources and Points	Emissions Control	Covered by Final NSPS
Crude Oil and Natural Gas Well Completions		
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC/Combustion	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**
Conventional Gas Wells	Combustion	
Oil Wells	Combustion	
Crude Oil and Natural Gas Well Recompletions		
Hydraulically Refractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC/Combustion	**X**
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**
Conventional Gas Wells	Combustion	
Oil Wells	Combustion	
Equipment Leaks		
Well Pads	NSPS Subpart VV	
Gathering and Boosting Stations	NSPS Subpart VV	
Processing Plants	NSPS Subpart VVa	**X**
Transmission Compressor Stations	NSPS Subpart VV	
Reciprocating Compressors		
Well Pads	Annual Monitoring/ Maintenance (AMM)	
Gathering and Boosting Stations	AMM	**X**
Processing Plants	AMM	**X**
Transmission Compressor Stations	AMM	
Underground Storage Facilities	AMM	
Centrifugal Compressors		
Processing Plants	Route to control	**X**
Transmission Compressor Stations	Route to control	
Pneumatic Controllers -		
Oil and Gas Production	Emissions limit	**X**
Natural Gas Transmission and Storage	Emissions limit	
Processing Plants	Emissions limit	**X**
Storage Vessels		
Emissions at least 6 tons per year	95% control	**X**
Emissions less than 6 tons per year	95% control	

As discussed in the Executive Summary, several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically fractured natural gas wells, capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. RECs also recover saleable hydrocarbon condensates that would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS. In the economic impact and energy economy analyses for the NSPS, we present results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emissions reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is therefore also in the baseline.[14] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

[14] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20 year voluntary initiative with participation from 124 natural gas companies operating in the U.S., including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that RECs can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the Agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

Additionally, in the RIA, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary RECs are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation, and serves in part to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are *required* to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the Docket, as referenced in Section 3.2.1 of this RIA. The table also includes the number of affected units projected under the primary baseline and the alternative regulatory baseline. Four issues are important to note regarding engineering compliance cost estimates: the approach to annualizing costs, the projection of affected units in the baseline; that estimate rental costs are used for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

Table 3-2 Summary of Projected No. of Affected Units Under Primary and Alternative Regulatory Baselines and Capital and Annualized Costs per Unit for Final NSPS Emissions Sources and Points

	Projected No. of Affected Units			Annualized Cost (2008$)	
Source/Emissions Point	**Primary Baseline**	**Alternative Regulatory Baseline**	**Capital Costs (2008$)**	**Without Rev. from Addl. Product Recovery**	**With Rev. from Addl. Product Recovery**
Hydraulically Fractured Natural Gas Well Completions					
Hydraulically Fractured Gas Wells that Meet Criteria for REC	4,107	8,382	$0	$33,237	-$1,543
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	1,377	1,377	$0	$3,523	$3,523
Hydraulically Refractured Natural Gas Well Completions					
Hydraulically Refractured Gas Wells that Meet Criteria for REC	532	1,085	$0	$33,237	-$1,543
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	121	121	$0	$3,523	$3,523
Equipment Leaks					
Processing Plants	29	29	$8,041	$12,273	$8,474
Reciprocating Compressors					
Gathering and Boosting Stations	210	210	$5,346	$2,456	$870
Processing Plants	209	209	$4,050	$2,090	-$2,227
Centrifugal Compressors					
Processing Plants	13	13	$22,000	$3,132	-$46,974
Pneumatic Controllers					
Oil and Gas Production	13,632	13,632	$165	$23	-$1,519
Processing Plants	15	15	$16,972	$11,090	$7,606
Storage Vessels					
Emissions at least 6 tons per year	304	304	$65,243	$19,864	$19,281

3.2.2.1.1 Approach to Annualizing Engineering Compliance Costs

Engineering capital costs were annualized using a 7 percent interest rate. However, 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)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

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. For example, a 15-year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels.

3.2.2.1.2 Projection of Affected Units

The projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA.

We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. In the National Energy Modeling System (NEMS) used by the EIA to produce the Annual Energy

Outlook identifies wells as being either a natural gas well or oil well. No criteria, such as a gas-oil ratio, for example, are applied within the model to a well to determine whether it is a natural gas well or an oil well. Additionally, EIA uses historical information as data for the NEMS. To collect these data, EIA relies upon States to submit information. States submit information about natural gas wells and oil wells based upon state-level approaches to classification, which varies greatly across States. In most instances, no national-level criteria are applied to reclassify the State-submitted information. To the extent that EPA's definition of a natural gas well differs from the various definitions used by States, potential differences in definitions may explain some difference between forecast impacts of the NSPS and the true costs incurred once the NSPS is implemented.

To approximate the number of natural gas wells that would not be required to combust emissions rather than perform a REC because they are wildcat (exploratory) and delineation wells, we draw upon the distinction in the EIA's analysis between exploratory and developmental wells. EIA defines an exploratory well as a "hole drilled a) to find and produce oil or gas in an area previously considered unproductive area; b) to find a new reservoir in a known field, i.e., one previously producing oil and gas from another reservoir, or c) to extend the limit of a known oil or gas reservoir." According to EIA, a "development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive." [15] The definitions of exploratory and developmental wells do not take into account whether the wells primarily produce crude oil or natural gas. For the impacts analysis, we assume exploratory wells as defined and estimated by EIA are equivalent to the NSPS-affected wildcat (exploratory) and delineation wells described in the NSPS as requiring to combust completion emissions rather than perform a REC.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[16] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[15] Source: 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.

[16] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, one percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations, as well as information reported to the EPA's Natural Gas STAR program. Based on the criterion relating to State regulations, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of recompletions of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. EPA does not have comprehensive information on the number of hydraulically fractured natural gas well completions that might be required by state or local regulations to combust completion emissions, which upon promulgation of this rule will be required to perform a REC. Based on the criterion relating to voluntary REC implementation, 51 percent of the completions and recompletions outside of regulated States are assumed to have been performed using a REC.

However, because the pressure level for some wells may be insufficient to successfully perform a REC, these wells will be required to combust emissions, rather than implement a REC. EPA analysis shows about 10 percent of the wells that otherwise would be required by the NSPS to perform a REC will combust emissions.

Table 3-3 Estimated New Hydraulically Fractured and Refractured Natural Gas Well Completions Affected by NSPS, 2015

	Hydraulically Fractured Natural Gas Well Completions of New Wells	Hydraulically Refractured Natural Gas Well Completions of Existing Wells
Nationwide Hydraulically Fractured Natural Gas Well Completions	11,403[1]	1,417[2]
Completions Exempt from NSPS REC Requirement		
Wildcat (Exploration Wells) and Delineation[1]	*446*	*0*
Low Pressure[3]	*931*	*121*
RECs Performed Absent Federal Regulation		
REC Already Required by States	*1,644*	*212*
Voluntarily Performed RECs Outside of Regulated States[4]	*4,275*	*553*
Total RECs Incrementally Required by NSPS	**4,107**	**532**
Total Completion Combustion Incrementally Required by NSPS	**1,377**	**121**

Note: sums may not total because of independent rounding.

1 Annual Energy Outlook 2011 Reference Case (successful completions in tight sands, shale, coalbed methane formations in 2015)

2 U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC. Also reflects revised assumptions regarding refracture frequency.

3 "NSPS Low Pressure Completion Threshold" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

4 "Voluntary Reductions from Gas Well Completions with Hydraulic Fracturing" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

Table 3-3 presents the accounting used for the estimate of the number of hydraulically fractured natural gas completions incrementally affected by the NSPS, after accounting for State regulation and voluntary action. In summary, we estimate 4,107 completions of new hydraulically fractured natural gas wells and 531 existing hydraulically refractured natural gas wells will incrementally be required to perform a REC in 2015. Additionally, we estimate 1,377 completions of new hydraulically fractured natural gas wells and 121 existing hydraulically refractured natural gas wells will be incrementally required to combust emissions in 2015. The methods to derive these figures are detailed in a technical memo in the Docket.[17]

It also should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as REC that capture emissions over short periods of time.

3.2.2.1.3 REC Unit Rental Costs

The completion requirements (combustion and REC) are essentially one-shot events and are generally performed by independent contractors. The emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later, if at all. After the completion is concluded, the REC equipment is typically moved by contractors to be reused during other well completions. Given that we base our REC costs on the average cost for contracting the REC as a service, we expect contractors' operation and maintenance costs, depreciations, and potential salvage value of the equipment to be reflected in the total contracting costs. Because of these factors, we decided to treat the hydraulically fractured natural gas well completion requirements solely as annualized costs.

3.2.2.1.4 Revenues from Natural Gas Product Recovery

For annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues from this product recovery. Several emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams

[17] "National Impacts of the NSPS OOOO Requirements on Gas Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

and sold. 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. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel. For the RIA, in the case of a REC, the revenues from captured and sold natural gas products are assumed to accrue in the same year as the REC is performed and only that year. For other environmental controls that avert the emission of saleable natural gas, such as pneumatic controllers, 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.

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. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $43 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-4 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The annual reporting and recordkeeping costs for the final NSPS are estimated at $2.6 million per year and are included in Table 3-4.

As can be seen from Table 3-4, which presents estimates, under the primary baseline, of nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness from controls associated with well completions and recompletions, hydraulically fractured natural gas wells provide the largest potential for emissions reductions from evaluated emissions sources and points. Controlling equipment leaks at processing plants presents the most significant compliance costs if revenue from additional natural gas recovery is not included. Table 3-5 presents the same set of information under the alternative regulatory baseline.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. Table 3-6 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the final NSPS under the primary baseline. The resulting total national annualized cost impact of the final NSPS rule is estimated at $170 million per year without considering revenues from additional natural gas recovery. Total national annualized costs for the final NSPS are estimated at -$15 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-4 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by NSPS Emissions Sources and Points, Primary Baseline, 2015

	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Hydraulically Fractured Natural Gas Well Completions							
Hydraulically Fractured Gas Wells that Meet Criteria for REC	$136,511,391	-$6,336,330	88,305	605,244	6,416	$1,546	-$72
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$4,850,956	$4,850,956	29,606	202,918	2,151	$164	$164
Hydraulically Refractured Natural Gas Well Completions							
Hydraulically Refractured Gas Wells that Meet Criteria for REC	$17,682,220	-$820,740	11,438	78,397	831	$1,546	-$72
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$426,264	$426,264	2,602	17,831	189	$164	$164
Equipment Leaks							
Processing Plants	$355,917	$245,746	132	475	5	$2,693	$1,860
Reciprocating Compressors							
Gathering and Boosting Stations	515,764	182,597	400	1,437	15	$1,291	$457
Processing Plants	436,806	-465,354	1,082	3,892	41	$404	-$430
Centrifugal Compressors							
Processing Plants	$40,720	-$610,657	254	2,810	9	$161	-$2,408
Pneumatic Controllers							
Oil and Gas Production	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Processing Plants	$166,351	$114,094	63	225	2	$2,659	$1,824
Storage Vessels							
Emissions at least 6 tons per year	$6,031,787	$5,855,032	29,654	6,490	876	$203	$197
Reporting and Recordkeeping	2,576,065	2,576,065	N/A	N/A	N/A	N/A	N/A
TOTAL	**$169,914,312**	**-$14,682,245**	**188,744**	**1,010,405**	**11,487**	**$900**	**-$78**

Table 3-5 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by NSPS Emissions Sources and Points, Alternative Regulatory Baseline, 2015

	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Hydraulically Fractured Natural Gas Well Completions							
Hydraulically Fractured Gas Wells that Meet Criteria for REC	$278,594,675	-$12,931,285	180,214	1,235,192	13,093	$1,546	-$72
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$4,850,956	$4,850,956	29,606	202,918	2,151	$164	$164
Hydraulically Refractured Natural Gas Well Completions							
Hydraulically Refractured Gas Wells that Meet Criteria for REC	$36,062,422	-$1,673,878	$23,328	$159,888	$1,695	$1,546	-$72
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$426,264	$426,264	$2,602	$17,831	$189	$164	$164
Equipment Leaks							
Processing Plants	$355,917	$245,746	$132	$475	$5	$2,693	$1,860
Reciprocating Compressors							
Gathering and Boosting Stations	$515,764	$182,597	$400	$1,437	$15	$1,291	$457
Processing Plants	$436,806	-$465,354	$1,082	$3,892	$41	$404	-$430
Centrifugal Compressors							
Processing Plants	$40,720	-$610,657	$254	$2,810	$9	$161	-$2,408
Pneumatic Controllers							
Oil and Gas Production	$320,071	-$20,699,918	$25,210	$90,685	$952	$13	-$821
Processing Plants	$166,351	$114,094	$63	$225	$2	$2,659	$1,824
Storage Vessels							
Emissions at least 6 tons per year	$6,031,787	$5,855,032	$29,654	$6,490	$876	$203	$197
Reporting and Recordkeeping	$2,576,065	$2,576,065	N/A	N/A	N/A	N/A	N/A
TOTAL	**$330,377,798**	**-$22,130,338**	**292,543**	**1,721,844**	**19,029**	**$1,129**	**-$76**

Table 3-6 Engineering Compliance Costs, Emission Reductions, and Cost-Effectiveness, Primary Baseline, NSPS (2008$)

	Final NSPS
Capital Costs	$24,803,968
Annualized Costs	
Without Revenues from Additional Natural Gas Product Recovery	$169,914,312
With Revenues from Additional Natural Gas Product Recovery	-$14,682,245
VOC Reductions (tons per year)	188,744
Methane Reduction (tons per year)	1,010,405
HAP Reductions (tons per year)	11,487
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$900
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$78

Note: The VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $43 million in 2008 dollars. The annualized cost estimates also include reporting and recordkeeping costs of $2.6 million.

As shown in Table 3-5, if voluntary action is not subsumed into the NSPS baseline, the emissions reductions achieved by the final NSPS are estimated at about 290,000 tons VOC, 19,000 tons HAP, and 1.7 million tons methane, and annualized costs without revenues from product recovery are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million.

As assumptions about natural gas prices, REC costs, and the potential emissions from hydraulically fractured natural gas well completions are influential on estimated impacts, we performed a pair of simple sensitivity analyses of the influence of these factors on the engineering costs estimate of the final NSPS. To perform this analysis, we vary the national average wellhead natural gas price from $2/Mcf to $7/Mcf while, first, varying REC costs and, second, varying the natural gas emissions that are captured by implementing a REC.

To characterize variation in REC costs, we use the data reported in the proposal TSD that were used to estimate the national average cost of performing a REC. On the low end of the range, we assume a REC costs $806 per day. This represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback. On the upper end of the range, we use $7,486 per day, which represents the cost in situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion. Like the primary analysis of the NSPS cost impacts, we use the average of these two values, $4,146 per day, to represent a mid-range case. Also like the primary NSPS impacts analysis, each REC also incurs include transportation and setup costs of $691 and completion combustion costs of $3,523 and assume an average flowback period of seven days. In sum, the low, average, and high REC costs are estimated at $9,856, $33,237, and $56,616, respectively.

For the mean estimate of the potential emissions from hydraulically fractured natural gas well completions, we use the 9,000 Mcf per completion which is used in the primary impacts analysis. To characterize the variation in potential natural gas emissions, we use the low and high ends of the 95 confidence interval around this mean estimate presented in a supporting technical memo.[18] The low-end estimate of potential emissions from hydraulically fractured natural gas well completions is estimated at 6,100 Mcf per completion and the high end at 11,700 Mcf per completion.

It is important to note two caveats to the analysis. First, while the gas price is largely a national-level parameter (producers will face similar wellhead prices across different regions), the REC costs and potential natural gas emissions may be highly variable across the country. Extrapolating what may be high or low end costs or potential natural gas emissions whose variation is driven by local or regional factors to a national-level estimate may overestimate or underestimate potential cost or emissions impacts. Second, this analysis holds the number of hydraulically fractured natural gas well completions constant regardless of economic conditions.

[18] "Statistical Analysis Memo: Development of a Bayesian Posterior Interval for the Emission Factor for Hydraulically Fractured Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Annex to the Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

It is likely that the decision to perform a REC without a regulatory requirement is conditioned on the producer having already decided to drill and hydraulically fracture a natural gas well. If economic and technical conditions are conducive to drilling and hydraulically fracturing a natural gas well, it is also possible that conditions are such that RECs are more likely to be profitable if performed. Conversely, if gas prices were low, we would expect fewer completions, and hence fewer RECs. Consequently, the assumption of a fixed number of completions will tend to overstate total compliance cost estimates.

Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead for the recovered natural gas (represented by the sloped lines), as well as a function of the low, average, or high REC costs assumed faced by all producers nationally. The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

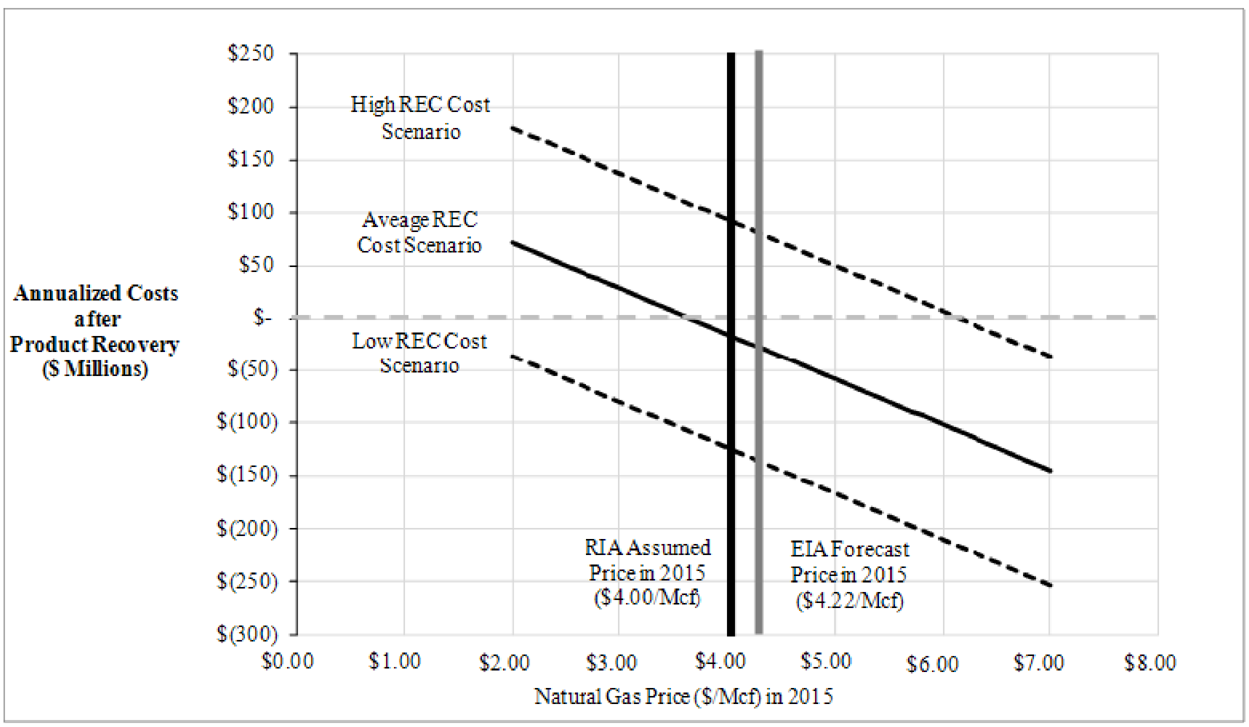

Figure 3-1 Sensitivity of Final NSPS Annualized Costs to Natural Gas Prices and REC Costs

As also shown in Table 3-6, at $4/Mcf and average REC costs, the annualized costs are estimated at -$15 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$24 million. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of lower savings and higher net costs) for the engineering costs analysis. The natural gas price at which the final NSPS breaks-even is around $3.66/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $43 million change in the annualized engineering costs of the final NSPS. Consequently, annualized engineering costs estimates would increase to about $29 million under a $3/Mcf price or decrease to about -$58 million under a $5/Mcf price.

Meanwhile, varying the REC costs shifts the line representing annualized costs downward in the low REC cost scenario and upward in the high REC cost scenario. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the low REC cost scenario would be about -$120 million. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the high REC cost scenario would be about $94 million.

Figure 3-2 similarly plots the annualized costs as function of the assumed price of natural gas paid to producers, but also depicts how the annualized costs might change when the potentials emissions might differ from our estimate of the national average well.

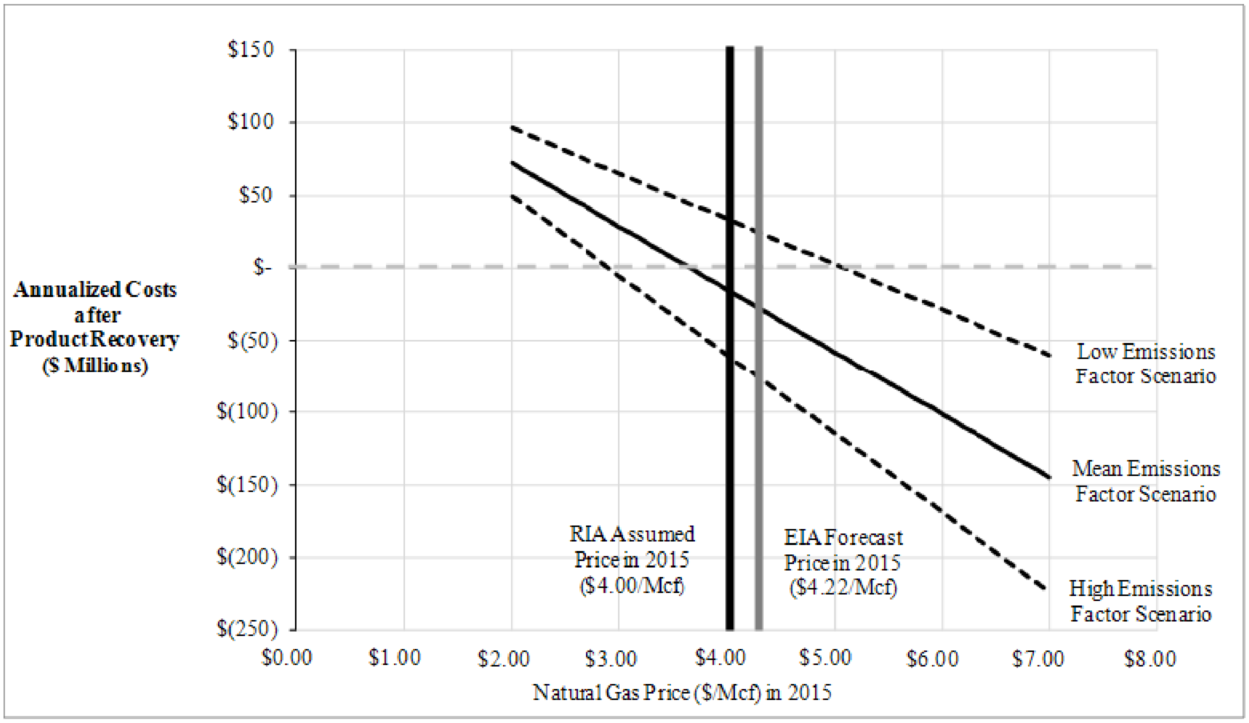

Figure 3-2 Sensitivity of Final NSPS Annualized Costs to Natural Gas Prices and Emissions Factor for Hydraulically Fractured Natural Gas Well Completions

As with the average REC costs, factor the annualized costs are estimated at -$15 million when using the average emissions. Varying the emissions factor shifts the line representing annualized costs upward in the low emissions factor scenario and downward in the high emissions factor cost scenario. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the low emissions factor scenario would be about $33 million. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the high emissions factor cost scenario would be about -$60 million.

The models used to forecast natural gas prices in the Annual Energy Outlook, also the source of our $4/Mcf wellhead natural gas price assumption, are deterministic. A deterministic model does not incorporate stochastic influences and produces the same result for each model run using the same inputs and parameters. While the Annual Energy Outlook is a commonly referenced publication that provides longer term forecasts, the U.S. EIA also produces the Short-Term Energy Outlook (STEO) which provides information about the probability distribution of energy prices over a shorter time frame. To better understand the uncertainty associated with the 2015 natural gas price assumed in this analysis, EPA reviewed the March 2012 STEO (U.S. EIA, 2012), which includes monthly forecasted natural gas prices through 2013. While the STEO analysis only extends to the end of 2013, the discussion of the distribution of possible future natural gas prices until that point can illuminate the uncertainty around longer-term forecasts.

In the STEO, forecasted prices are a function of the volatility associated with a future-delivery contract, as well as the length of time until contract expiration. The STEO also incorporates an analysis of the probabilities that natural gas prices would fall below or exceed specified prices through 2013. We note, however, that the probability analysis uses the Henry Hub spot price, rather than the wellhead price paid to producer. The Henry Hub price will reflect markups for processing and transportation unlike the wellhead price.[19] In December 2013, the EIA analysis projects a Henry Hub price of $4.28/million Btu (or $4.40/Mcf[20]) with a 90 percent confidence interval of $2.36 to $7.16/million Btu.

Also, the STEO reports that based upon futures prices as of February 2012, spot natural gas prices in December 2013 at the Henry Hub have a 40 percent probability of being greater than $4.00 per million Btu; a 30 percent probability of being greater than $4.50 per million Btu; a 20 percent probability of being greater than $5.00 per million Btu; and a 10 percent probability of being less than $2.50 per million Btu (U.S. EIA, 2012). While this information is not directly comparable to the wellhead natural gas price, the probability analysis highlights the challenges associated with precisely predicting future natural gas prices.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-4 for these combustion-type controls, the final NSPS is

[19] The National Energy Modeling System used to produce the Annual Energy Outlook does not explicitly model prices at the Henry Hub. Rather, the model uses an econometric equation to predict Henry Hub prices from modeled wellhead prices. For the forecasts presented in 2012 Annual Energy Outlook, this equation predicts the Henry Hub price to be about 13 percent higher than the wellhead price.

[20] The 2015 natural gas price used in EPA's analysis is in units of thousand cubic feet and the spot natural gas prices used in the probability analysis are in units of million Btu. The conversion factor we used to convert the Btu measure to the cubic foot measure is 1 Mcf equals 1.027 million Btu. While EPA is able to convert the mean estimate of future natural gas prices, we are not able to convert the distribution around the mean without additional information that was used in the probability analysis.

estimated to capture about 43 billion cubic feet (bcf) of natural gas and 160,000 barrels of condensate. Estimates of unit-level and nation-level product recovery are presented in Table 3-7 below. Note that completion-related requirements for new and existing wells generate all the condensate recovery for the NSPS. For natural gas recovery, RECs contribute about 38 bcf (or 87 percent).

Table 3-7 Estimates of Control Unit-level and National-level Natural Gas and Condensate Recovery, Sources and Emissions Points, Primary Baseline, NSPS, 2015

		Unit-level Product Recovery		Total Product Recovery	
Source/ Emissions Points	Projected No. of Affected Units	Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions					
Hydraulically Fractured Gas Wells that Meet Criteria for REC	4,107	8,100	34	33,268,158	139,644
Hydraulically Refractured Gas Wells that Meet Criteria for REC	532	8,100	34	4,309,200	18,088
Equipment Leaks					
Processing Plants	29	950	0	27,548	0
Reciprocating Compressors					
Gathering and Boosting Stations	210	397	0	83,370	0
Processing Plants	209	1,079	0	225,540	0
Centrifugal Compressors					
Processing Plants	13	12,526	0	162,844	0
Pneumatic Controllers					
Oil and Gas Production	13,632	386	0	5,254,997	0
Processing Plants	15	871	0	13,064	0
Storage Vessels					
Emissions at least 6 tons per year	304	146	0	44,189	0
Total (Mcf)				**43,388,910**	**157,732**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that is reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately be consumed by final consumers.

After making these adjustments, we estimate that the final NSPS will potentially recover about 34 bcf of natural gas that will ultimately be consumed by natural gas consumers.[21] EIA forecasts that the domestic dry natural gas production in 2015 will be 22.4 tcf. Consequently, the final NSPS may recover production representing about 0.15 percent of domestic dry natural gas production predicted in 2015. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decision-making.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-8). The rates of return presented in Table 3-8 are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: $\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100$.

Table 3-8 Simple Rate of Return Estimate for Final NSPS Controls, Primary Baseline

Emission Point	Control Option	Cost of Control	Revenues from Product Recovery	Estimated Rate of Return
New Completions of Hydraulically Fractured Wells	REC/ Combustion	$33,237	$34,780	4.6%
Reciprocating Compressors (Processing Plants)	Replace packing	$2,090	$4,317	106.5%
Centrifugal Compressors (Processing Plants)	Route to control	$3,132	$50,106	1499.7%
Pneumatic Controllers (Oil and Gas Production)	Emissions limit	$23	$1,542	6467.3%
Overall NSPS*		**$169,914,312***	**$184,596,889***	**8.6%***

* Costs and estimated rate of return for overall NSPS based on national costs of rule, not per unit costs like the other items in the table.
Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

[21] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers vary greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 4.6 percent rate estimated for a REC, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware of, without government intervention. The cost analysis of this RIA nevertheless is based on the observation that emission reductions that appear to be profitable, on average, in our analysis have not been adopted by a significant segment of the industry. This observation, often termed the "energy paradox", has been noted to occur in other contexts too where consumers and firms appear to undervalue a wide range of investments in energy conservation, even when they pay off over relatively short time periods.[22] We discuss some possible explanations for the apparent paradox in this context. First, there may be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. In the event that the environmental investment displaces other investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. However, if firms are not capital constrained, then there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost. If firms should face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm. To the extent that any opportunity costs are not added to the control costs, the compliance costs presented above may be underestimated.

A second explanation could be that the average impacts identified in this RIA are not reflective of the true costs and benefits of the RECs that are compelled by the regulation, relative

[22] See U.S. EPA (2011) for more discussion and a review of the economics literature examining why firms may not adopt technologies that would be expected to increase their profits. (U.S. EPA. 2011. Final Rulemaking to Establish Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles. Regulatory Impact Analysis. http://www.epa.gov/otaq/climate/documents/420r11901.pdf).

to the RECs performed voluntarily. In this final rule, based on public comments and explained above, EPA has identified several circumstances under which RECs would not be feasible or cost-effective, and has allowed firms to continue to use combustion devices only for those completions and recompletions. In addition to these general categories, the natural variation in well-head prices, cost, or other technical issues may mean that the rational decision to not complete using a REC in the absence of this regulation in certain circumstances may not be captured by the analysis of central estimate impacts contained in this RIA. In part to address this issue, EPA has provided the break-even analysis above, as well as a sensitivity analysis where we vary several parameters that may influence individual REC decision-making.

Third, the assumed \$4/Mcf payment rate does not reflect any taxes or royalties that might apply to producers implementing the control technologies. We expect that royalties and taxes influence producers' economic and operational decisions, particularly at the margin, as these royalties or taxes reduce potential net returns and prevent adoption of environmental controls. However, there are various reductions in taxable income and incentives that can serve to reduce costs which also can affect decisionmaking. For example, firms may be able to deduct pollution control expenditures and depreciation from income taxes. Also, for the oil and natural gas industry, producers may be eligible for deductions of intangible drilling costs and other state or federal production and investment credits. Historically, EPA has not estimated post-tax (or post-royalty) compliance costs (which are typically cost-reducing) in compliance cost estimation as this requires information and tax accounting beyond the scope of the analyses.

A third explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since a significant percent of new natural gas well completions with hydraulic fracturing and existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled in the baseline, it is unlikely that a lack of information will be a major reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Finally, the cost from the irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms.

With these caveats in mind, EPA believes it is analytically appropriate to analyze engineering compliance costs presented in Table 3-2 and Table 3-4 using the additional product recovery and associated revenues. EPA continues to explore what factors could explain apparent underinvestment in cost-effective emission reducing technologies absent government regulation, and the measurement of opportunity costs more generally.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined two emissions points as part of its analysis for the final NESHAP Amendments. Unlike the controls for the final NSPS, the controls evaluated under the final NESHAP Amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-9 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAP, VOC, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon annualized engineering costs.

Table 3-9 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Final NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annual-ized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year)			HAP Reduction Cost-Effectiveness (2008$/ton)
					HAP	VOC	Methane	
Production - Small Glycol Dehydrators	74	35,518	22,396	1,657,300	505	915	316	3,284
Transmission - Small Glycol Dehydrators	7	19,399	18,957	132,700	164	298	103	808
Reporting and Recordkeeping	N/A	N/A	N/A	1,694,907	N/A	N/A	N/A	N/A
Total	**81**			**3,484,907**	**669**	**1,213**	**419**	**5,209**

Note: Totals may not sum due to independent rounding.

Under the final NESHAP Amendments, about 81 controls will be required, costing a total of $3.5 million annually (Table 3-9). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of final amendments. These controls will reduce HAP emissions by about 670 tons, VOC emissions by about 1,200 tons, and methane by about 420 tons. The cost-per-ton to reduce HAP emissions is estimated at about $5,200 per ton. All figures are in 2008 dollars.

3.3 References

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4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The final Oil and Natural Gas NSPS and NESHAP Amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAP, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; 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, as explained below. For the final NSPS, the HAP and climate benefits can be considered "co-benefits", and for the final NESHAP Amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAP and methane.

The final NSPS is anticipated to prevent, 190,000 tons of VOC, 11,000 tons of HAP, and 1.0 million tons of methane from new sources, while the final NESHAP Amendments are anticipated to reduce 670 tons of HAP, 1,200 tons of VOC, and 420 tons of methane from existing sources. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC). The specific control technologies for the NESHAP Amendments are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 18 million metric tons for the final NSPS and 8,000 metric tons for the final NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, 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 addition, we do not yet have interagency agreed upon valuation estimates for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Section 6 of this RIA. A break-even analysis answers the question, “What would the benefits need to be for the benefits to exceed the costs.” While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOC and HAP including wells, 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 these rules, 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 these rules might affect attainment status without air quality modeling data.[24]

[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 for the break-even analysis, 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.

[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.

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. In short, 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 account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for implementation rules are generally from a specific class of well-characterized sources. In general, 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. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules. 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 are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with the Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS
	Primary Baseline	
HAP	669	11,487
VOC	1,213	188,741
Methane	419	1,010,382
	Alternative Regulatory Baseline	
HAP	669	19,028
VOC	1,213	292,532
Methane	419	1,721,763

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOC and HAP are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as “producer-side” impacts.[25] For example, by combusting VOC and HAP, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to “producer-side” impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as “consumer-side” secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[25] In previous RIAs, we have also referred to these impacts as energy disbenefits.

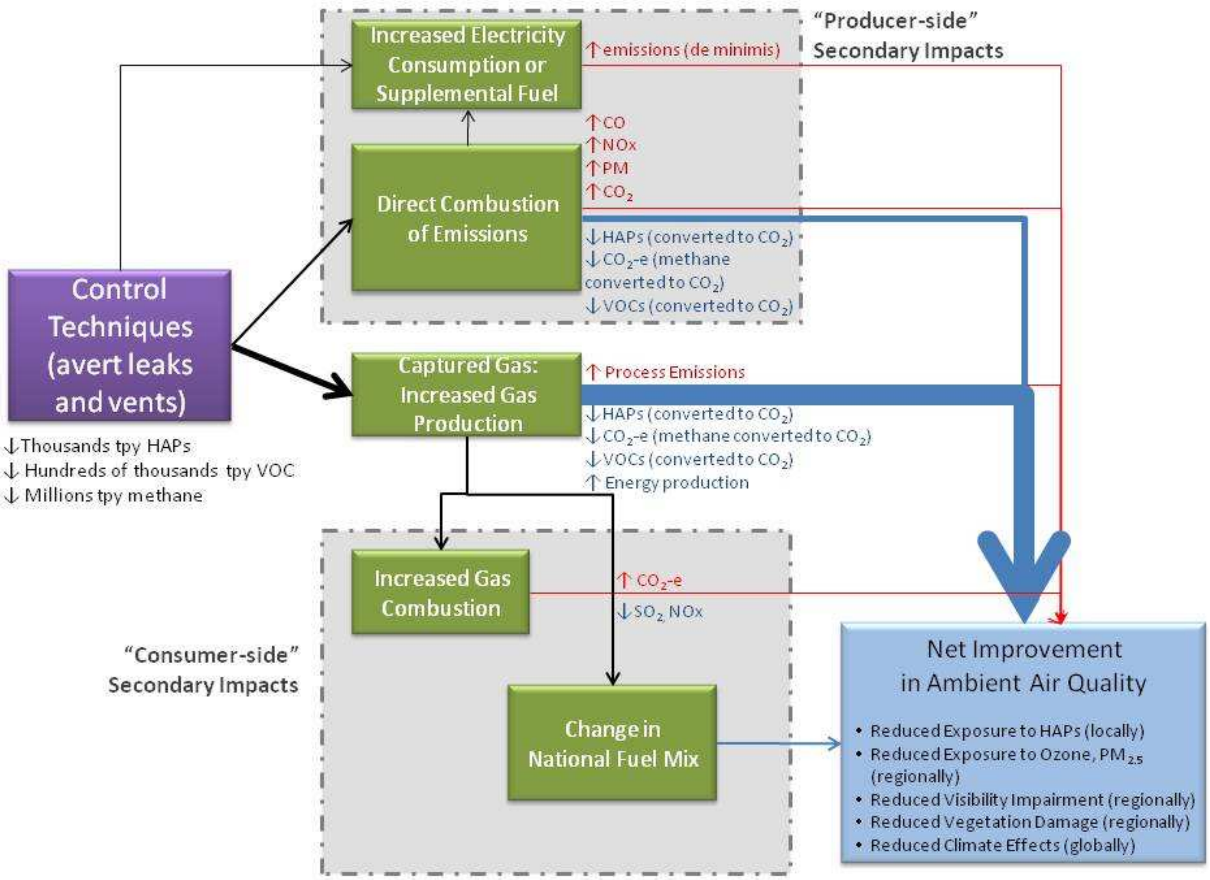

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[26]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category, Primary Baseline ("Producer-Side") (short tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Total Completions of New Gas Wells (NSPS)	981,559	504	15	2,745	1,039
New Gas Well Completions: REC/Combust	*133,177*	*68*	*0*	*372*	*141*
New Gas Well Completions: Combust	*848,382*	*436*	*15*	*2,373*	*898*
Existing Well Recompletions: Combust	91,800	47	1	257	97
Existing Well Completions: REC/Combust	*17,251*	*9*	*0*	*48*	*18*
Existing Well Completions: Combust	*74,549*	*38*	*1*	*208*	*79*
Pneumatic Controllers (NSPS)	22.0	1.0	2.6	0.0	0.0
Storage Vessels (NSPS)	856.0	0.5	0.0	2.4	0.9
Total NSPS	**1,074,237**	**553**	**19**	**3,004**	**1,137**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the final NSPS on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[27] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 0.65 million metric tons for the final NSPS and NESHAP Amendments in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 17.7 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. While the NEMS is designed to estimate changes in fuel consumption as economic and regulatory factors change (such as are shown in Table 7-11), the NEMS is unable to estimate national-level emissions of criteria pollutants.

[26] This issue is discussed in more detail in Section 4.7 of this RIA.
[27] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Final Oil and Gas NSPS and NESHAP Amendments in 2015 (million metric tonnes) ("Consumer-Side")[1]

Fuel Type	NSPS (million metric tons change in CO_2-e)
Petroleum	-0.07
Natural Gas	0.04
Coal	0.68
Other	0.00
Total modeled Change in CO_2-e Emissions	**0.65**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Final Oil and Gas NSPS and NESHAP Amendments in 2015 (million metric tonnes)

Emissions Source	**NSPS**	**NESHAP Amendments**
Averted CO_2-e Emissions from New Sources[1]	-19.2	-0.008
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.97	N/A
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	0.65	N/A
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-17.6**	**-0.008**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons.

[3] This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3 and reflects both NSPS and NESHAP Amendments.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each rule.

Table 4-5 Summary of Emissions Changes for the Final Oil and Gas NSPS and NESHAP Amendments in 2015 (short tons per year)

	Pollutant	NSPS	NESHAP Amendments
Change in Direct Emissions	VOC	-190,000	-670
	Methane	-1,000,000	-1,200
	HAP	-11,000	-420
Change in Secondary Emissions (Producer-Side)	CO_2	1,100,000	N/A
	NOx	550	N/A
	PM	19	N/A
	CO	3,000	N/A
	THC	1,100	N/A
Change in Secondary Emissions (Consumer-Side)	CO_2-e	720,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e (short tons)	-19,000,000	-8,800
	CO_2-e (metric tonnes)	-18,000,000	-8,000

Note: Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, 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).[28] 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, U.S. EPA conducts the NATA.[29] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

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

[29] 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/

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

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

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

Based on the 2005 NATA, 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 cancer risks are formaldehyde and benzene.[30,31] 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,[32] subchronic,[33] or acute[34] inhalation exposures 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.

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[30] 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.

[31] 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.

[32] 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).

[33] 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).

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

Figure 4-2 and Figure 4-3 depict the 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 are more than double acrolein emissions on a national basis, according to 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 toxic than acetaldehyde.[35] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

[35] 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.

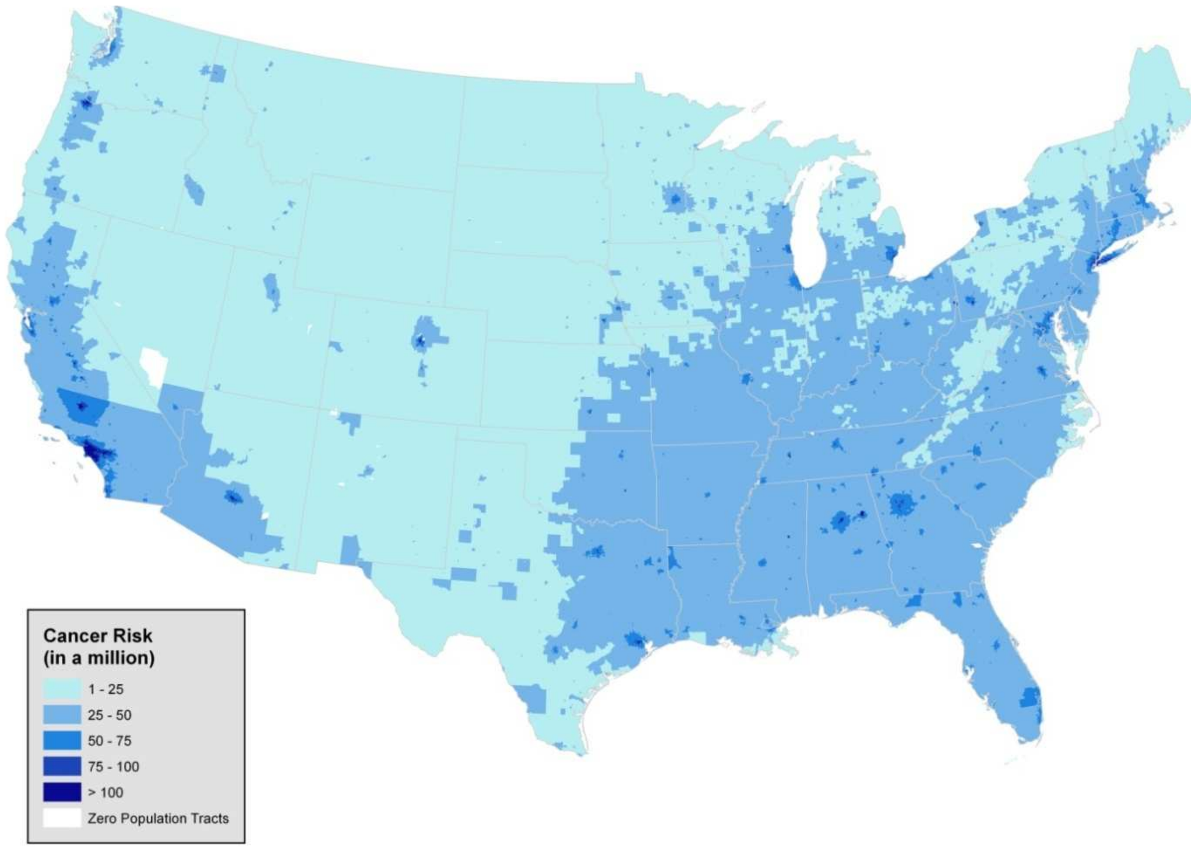

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

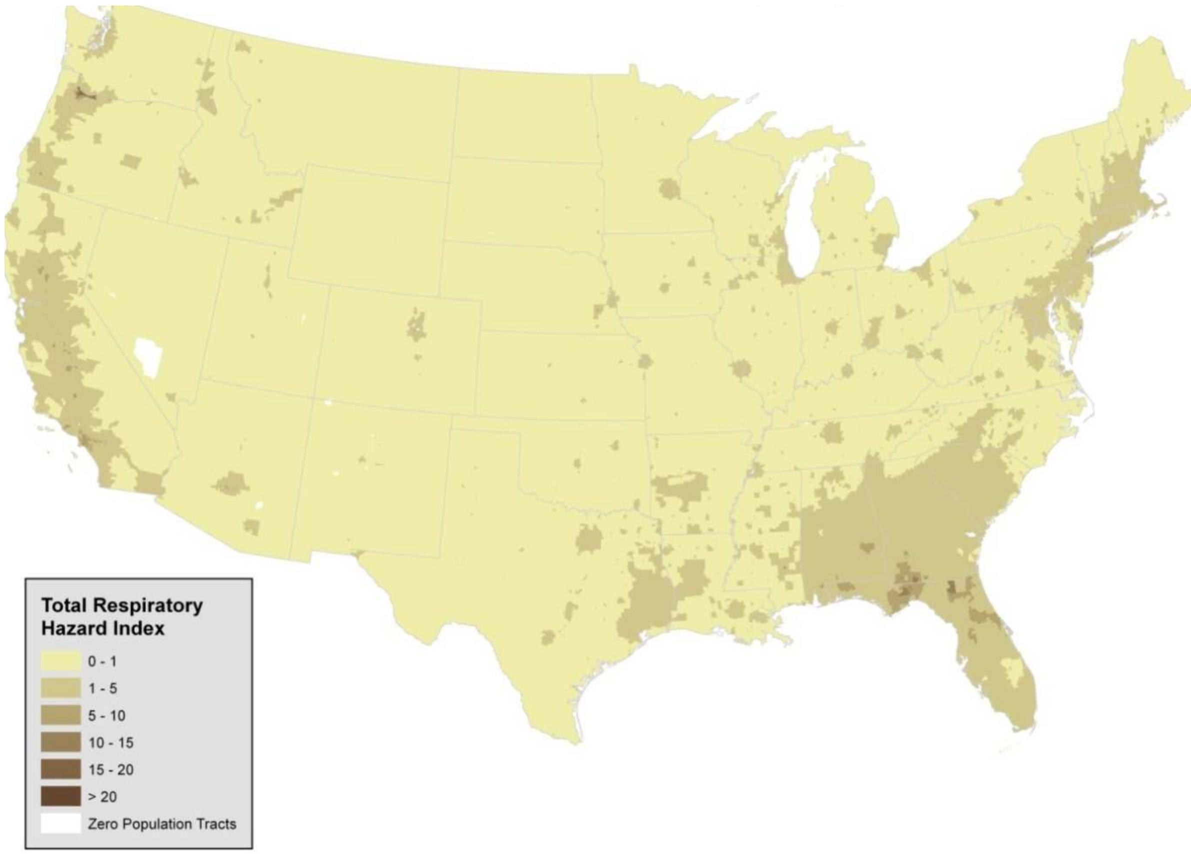

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

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 these rules. In a few previous analyses of the benefits of reductions in HAP, EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[36] 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. 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

[36] The unit risk factor 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 µg/m^3 of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

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

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

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). 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, 2011a). 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. These rules combined are anticipated to avoid or reduce 20,000 tons of HAP per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2012). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 10 in-a-million for existing sources with a cancer incidence of 0.02 before and after controls. Approximately 120,000 people are estimated to have cancer risks at or above 1-in-1 million for oil and gas production. For existing natural gas transmission and storage, the maximum individual cancer risk could be 20-in-a-million with a cancer incidence of 0.001. Approximately 1,100 people are estimated to have cancer risks at or above 1-in-1 million for oil and gas transmission and storage. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. It is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are much higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 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.[37,38,39] EPA states in its IRIS database that data indicate a causal

[37] 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.

[38] 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.

[39] 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.

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 Services (DHHS) has characterized benzene as a known human carcinogen.[40,41] 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.[42,43] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[44,45] 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.[46,47,48,49] EPA's IRIS program has not yet evaluated these new data.

[40] 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.

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

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

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

[44] 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.

[45] 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.

[46] 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.

[47] 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.

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

[49] 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.

4.4.2 Toluene[50]

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

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

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

4.4.3 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

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[50] 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>.

the eyes and skin in humans.[51] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[52]

4.4.4 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.[53,54] 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).[55,56] The NTP (1999) carried out a chronic inhalation

[51] 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.

[52] 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.

[53] 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.

[54] 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.

[55] 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.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 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.[57] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[58] 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.[59] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 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

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[56] 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.

[57] 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.

[58] 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.

[59] 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.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[60]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[61]

4.5 VOC

4.5.1 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 carbon dioxide (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

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60 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>.

61 U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

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 time limitations under the court-ordered schedule and data limitations regarding locations of new well completions, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ 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, 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, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although 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).

EPA 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, EPA estimates PM-related 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). 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 City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[62] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, 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

[62] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$, 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.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOC (2008$)

Area	Pope et al.	Laden et al.	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	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume 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 updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. 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. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 *Organic PM welfare effects*

According to the residual risk assessment for this sector (U.S. EPA, 2011a), 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 the 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).

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.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ 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, 2011g; U.S. EPA, 2011a) 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.

4.6 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 (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOC and CO are important compounds for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). 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). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. 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 NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule and data limitations, we were unable to perform air quality modeling for this rule. 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 well completions, we are unable to estimate the effect that reducing VOC will have on ambient ozone concentrations without air quality modeling.

4.6.1 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). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOC from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[63] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOC reduced. 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

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

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 these rules, even as a bounding exercise.

4.6.2 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, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan 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 plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). 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 discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

4.7 Methane (CH_4)

4.7.1 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) Fourth Assessment Report (2007), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 18% 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 0.86 W/m^2 of forcing today, which is about 30% of the 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: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this final rule includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 MMtCO_2-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 MMtCO_2-e.

This rulemaking finalizes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The NSPS is expected to reduce methane emissions annually by about 1.0 million short tons or approximately 19 million metric tons CO_2-e. These reductions represent about 7 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 MMTCO_2-e). This annual CO_2-e reduction becomes about 18 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are equivalent of taking approximately 4 million typical passenger cars off the road or eliminating electricity use from about 2 million typical homes each year.[64]

EPA estimates the social benefits of regulatory actions that have a small or “marginal” impact on cumulative global CO_2 emissions using the “social cost of carbon” (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the

[64] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 02/13/12.

final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: $6, $25, $40, and $76 per metric ton of CO_2 emissions in 2015, in 2008 dollars.[65] The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models 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. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

[65] The interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. The development of a domestic SCC is greatly complicated by the relatively few region- or country-specific estimates of SCC in the literature. See Interagency Working Group on Social Cost of Carbon. 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a relatively shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by longer-lived gases such as CO_2, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

The EPA recognizes that the methane reductions finalized in this rule will provide significant economic climate co-benefits to society. However, the 2009-2010 Interagency Social Cost of Carbon Work Group did not produce directly modeled estimates of the social cost of methane. In the absence of direct model estimates from the interagency analysis, EPA has used a "global warming potential (GWP) approach" to estimate the dollar value of this rule's methane co-benefits. Specifically, EPA of converted methane to CO_2 equivalents using the GWP of methane, then multiplied these CO_2-equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group.

EPA requested comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. EPA's response to these comments, as well as a summary of the public comments sent in response to this request, is provided in the response to comments document.

Applying the GWP approach, these co-benefits equate to a range of approximately $130 to $1,600 per metric ton of methane reduced depending upon the discount rate assumed, with an estimate of $840 per ton using the mean SCC at the 3 percent discount rate.[66] When including expected methane emission reductions from the NESHAP Amendments and NSPS and considering secondary impacts of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $100 million to about $1.3 billion; the mean SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $440 million in 2015 (Table 4-7).

[66] The per ton estimates range from approximately $110 to $1400 per short ton of methane reduced, depending on the discount rate assumed, with an estimate of $480 per short ton of methane, using the mean SCC at 3% discount rate.

Table 4-7 Climate Methane Benefits Using 'GWP' Approach

SCC Value for 2015 emission reductions ($/ton CO_2 in 2008 dollars) [1]	Total Benefits based on 100 year GWP adjustment[2] (millions 2008$) Final NSPS	Final NESHAP Amendments
$6 (mean 5% discount rate)	$100	$0.05
$25 (mean 3% discount rate)	$440	$0.20
$40 (mean 2.5% discount rate)	$700	$0.32
$76 (95th percentile at 3% discount rate)	$1,300	$0.60
Methane Emission Reductions [3] (MMT CO_2-e)	**17.6**	**0.008**

[1] SCC values for 2015 from the SCC TSD in the light duty vehicle rule adjusted to reflect 2008$ using the CPI-U from the Bureau of Labor Statistics.
[2] Estimates are given for illustrative purposes and represent the CO_2-e estimate of methane reductions multiplied by the SCC estimates ("GWP approach").CO_2-e calculated using the GWP of 21 (SAR). These co-benefit estimates are not the same as would be derived using a social cost of methane directly computed from integrated assessment models. See Marten and Newbold (2011) for discussion of the limitations of the GWP approach.
[3] Estimates include methane reductions from the NSPS and NESHAP Amendments respectively and consider secondary impacts from Table 4-4.
Note: Results reflect independent rounding.

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer (details below). This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas rule. The use of the SAR GWP values allows comparability of data collected in this final rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions finalized in this rulemaking.

Given the uncertainties with both the ‘GWP approach’ estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this final rule. Rather, the EPA presents the ‘GWP approach’ climate co-benefit estimates as an interim method to produce estimates until the interagency group develops values for non-CO_2 GHGs.

4.7.2 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Approximately 40% 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 NOx and VOC, 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 NOx, carbon monoxide, or non-methane VOC may have larger local health benefits from greater reductions in ozone concentrations (West and Fiore, 2005; West et al., 2006, 2007; Fiore et al. 2008; Dentener et al., 2005; Shindell et al., 2005, 2012; UNEP/WMO, 2011).VOC The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.3 Combined methane and ozone effects

A recent United Nations Environment Programme (UNEP) assessment provides the most comprehensive analysis to date of the health, climate, and agricultural benefits of measures to reduce methane, as well as black carbon, a component of fine particulate matter that absorbs radiation (UNEP/WMO, 2011; Shindell et al., 2012). The UNEP assessment found that while reducing longer-lived GHGs such as CO_2 is necessary to protect against long-term climate change, reducing global methane and black carbon emissions would have global health benefits by reducing exposure to ozone and $PM_{2.5}$ as well as potentially slowing the rate of climate change within the first half of this century. Relative to a business as usual reference scenario, implementing methane mitigation measures that achieve approximately 40% reductions in global methane emissions were estimated to avoid approximately 0.3° C globally averaged warming in 2050 (including the impacts of both methane itself and subsequently formed ozone) and 47,000 ozone-related premature deaths and 27 million metric tons of ozone-related crop yield losses globally in 2030 (Shindell et al., 2012). These benefits, including global climate impacts of methane and resulting ozone changes, and global ozone-related health and agricultural impacts, were valued at $700 to $5,000 per metric ton[67]. The methane measures examined include extended methane recovery/utilization and reduced fugitive emissions from oil and gas production, which contributed the greatest climate benefit of all methane mitigation measures in North America and Europe (UNEP, 2011).

4.8 References

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[67] Benefit per ton values derived from Shindell et al. (2012) cannot be directly compared to, nor are they additive with, the ozone health benefit-per-ton estimates for the U.S. reported in Section 4.6.1, since they include climate and agricultural impacts, are calculated for global rather than U.S. impacts, and use different assumptions for the value of a statistical life. Similarly, these values cannot be compared to, nor are they additive with, the methane climate valuation estimates in Section 4.7.1 since they include health and agricultural benefits and use different assumptions for the Social Cost of Carbon.

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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. Table 5-1 shows the results of the cost and benefits analysis for these final rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS and NESHAP Amendments in 2015[1]

	NSPS	**NESHAP Amendments**	**NSPS and NESHAP Amendments Combined**
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$15 million	$3.5 million	-$11 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits[6]	11,000 tons of HAP	670 tons of HAP	12,000 tons of HAP
	190,000 tons of VOC	1,200 tons of VOC	190,000 tons of VOC
	1.0 million tons of methane	420 tons of methane	1.0 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas product recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; 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.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits.

[6] The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides NOx, 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

5.2 Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C.

3501, et seq. The information collection requirements are not enforceable until OMB approves them.

The ICR documents prepared by the EPA have been assigned EPA ICR numbers 2437.01, 2438.01, 2439.01 and 2440.01. The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). 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. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart HH or 40 CFR part 63, subpart HHH. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, the EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA’s estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate a total of 39 such occurrences for all sources subject to 40 CFR part 63, subpart HH, a total of three such occurrences for all sources subject to 40 CFR part 63, subpart HHH, and a total of 6 such occurrences for all sources subject to 40 CFR part 60, subparts KKK and LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $20.1 million. This includes 384,866 labor hours per year at a total labor cost of $19.5 million per year, and annualized capital costs of $0.36 million, and annual operating and maintenance costs of $0.20 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2008 dollars and represent the most cost effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICR are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rule.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act 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 (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business as defined by NAICS codes 211111, 211112, 221210, 486110 and 486210; 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.

For the final NSPS, the EPA performed an analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. The baseline used in this analysis takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket.

When revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (97 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

For the final NESHAP Amendments, we estimate that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed an analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none are likely to have impacts greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.

After considering the economic impact of the combined NSPS and NESHAP amendments on small entities, I certify this action will not have a significant impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) in the sample are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, none of the 136 small firms (100 percent) are likely to have impacts of greater than 1 percent.

Our determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions occur over a short span of time, during which the additional product recovery is also accomplished and payments for recovered products are settled.

Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This final action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531-1538 for state, local, and tribal governments, in the aggregate, or to the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

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, as specified in Executive Order 13132. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action will not have tribal implications because it doesn’t impose a significant cost to the tribal government. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country.

The EPA initiated a consultation process with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. During the consultation process, the EPA conducted outreach and information meetings prior to the proposal in 2010. The EPA met with the Inter Tribal Environmental Council, which include many of the Region VI tribes, The Tribal leadership summit in Region X, and Tribal Energy Conference hosted by Ft. Belknap, and the National Tribal Forum.

After the proposal was published, letters were sent to all tribal leaders offering to consult on a government-to-government basis on the rule. As part of the consultation process and in response to these letters, an outreach call was held on October 12, 2011. Tribes that participated on this call were: Fond du Lac Band of Lake Superior Chippewa, Fort Belknap Indian

Community, Forest County Potawatomi Community, Southern Ute Indian Tribe, and Pueblo of Santa Clara.

In this meeting the tribes were presented the information in the proposal. The tribes asked general clarifying questions but did not provide specific comments. Comments on the proposal were received from an affiliate of the Southern Ute Indian Tribe. The commenter expressed concern about the impacts of the rule on natural gas and oil production operations on the Southern Ute Indian reservation and requested additional time to evaluate the impacts. In response to this and other requests, the comment period was extended. More specific comments can be found in the docket.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. The EPA's risk assessments (included in the docket for this final rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

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

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. These final rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The final NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001). The final NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NSPS is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The basis for these determinations is as follows. Emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the final NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the final rules.

We use the National Energy Modeling System (NEMS) to estimate the impacts of the combined final rules 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.

Based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques, which are required by the final NSPS for certain completions of hydraulically fractured and refractured natural gas wells, voluntarily based upon economic and environmental objectives. The baseline used for the energy system impacts analysis takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket.

The analysis of energy system impacts for the final NSPS under the primary baseline shows that domestic natural gas production is not likely to change in 2015, the year used in the

RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

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 final rule, please see Section 7 of this RIA.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the EPA decides not to use available and applicable VCS.

This final action does not involve technical standards. Therefore, the EPA is not considering the use of any VCS.

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low income populations in the United States.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it 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.

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the percentages of various social, demographic, and economic groups within the at-risk population living near the facilities where these source categories are located and compared them to national averages. The development of demographic analyses to inform the consideration of environmental justice issues in the EPA rulemakings is an evolving science.

The EPA conducted a demographic analysis, focusing on populations within 50 km of any facility in each of the source categories that are estimated to have HAP exposures which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater based on estimates of current HAP emissions. The results of this analysis are documented in the technical report: Risk and Technology Review – Analysis of Socio-economic Factors for Populations Living Near Oil & Natural Gas Production Facilities located in the docket for this rulemaking.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic non-cancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

To promote meaningful involvement, the EPA conducted three public hearings on the proposal. The hearings were held in Pittsburgh, Pennsylvania, on September 27, 2011, Denver, Colorado, on September 28, 2011, and Arlington, Texas, on September 29, 2011. A total of 261 people spoke at the three hearings and 735 people attended the hearings. The attendees at the hearings included private citizens, community-based and environmental organizations, industry representatives, associations representing industry and local and state government officials.

5.11 Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2).

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total annualized engineering cost of the final NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$15 million. EPA anticipates that this rule would prevent 190,000 tons of VOC, 1.0 million tons of methane, and 11,000 tons of HAP in 2015 from new sources. In 2015, EPA estimates the annualized costs for the NESHAP Amendments to be 3.5 million.[68] EPA anticipates that this rule would reduce 1,200 tons of VOC, 420 tons of methane, and 670 tons of HAP in 2015 from existing sources. For the NESHAP Amendments, a break-even analysis suggests that HAP emissions would need to be valued at $5,200 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $2,900 per ton or the methane emissions would need to be valued at $8,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the final NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price of natural

[68] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

gas would need to be at least $3.66 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.22 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOC, HAP, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOC would need to be valued at about $150 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

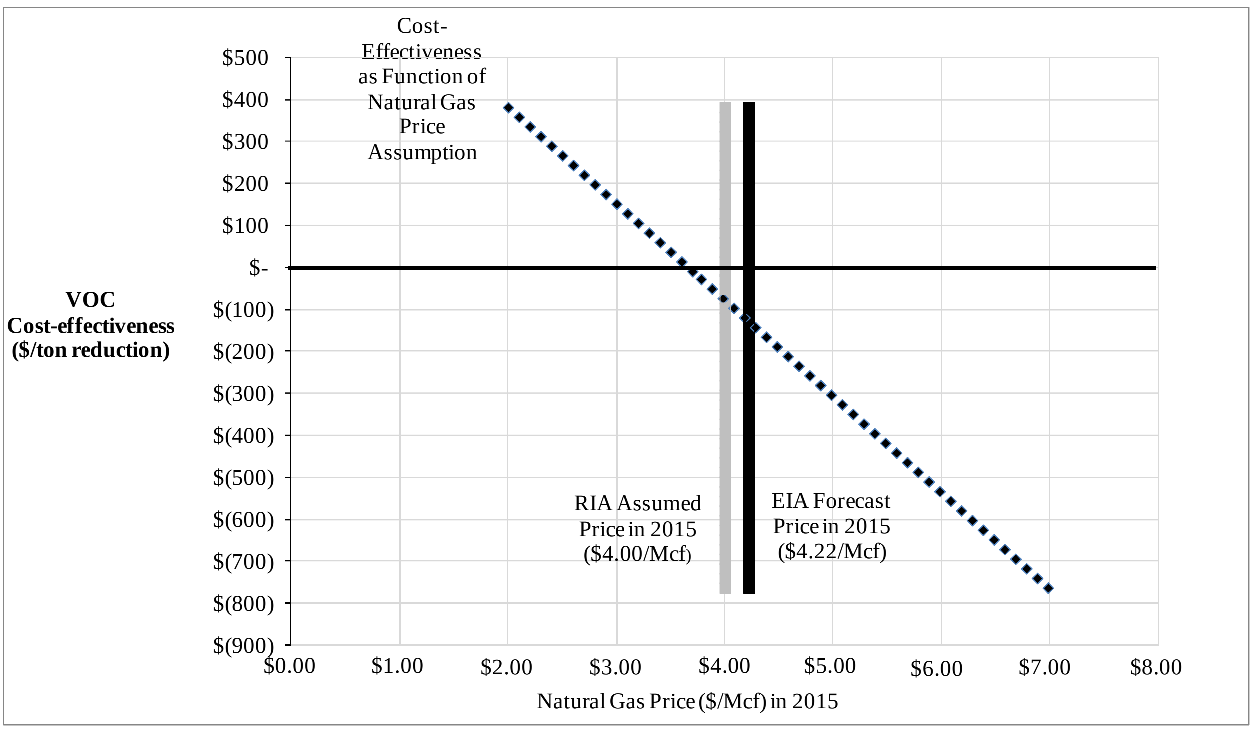

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits of VOC emissions are valued at $280 to $7,000 per ton across a range of eight urban areas.[69] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced.

[69] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Using the GWP approach, the climate co-benefits range from approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOC contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only $3.00 per Mcf, it is likely that the VOC benefits would exceed the costs. As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAP, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP Amendments, respectively. The NSPS analysis assumes that RECs performed voluntarily or in States where these emissions are already regulated would continue in absence of Federal regulation. Table 6-3 provides a summary of the direct and secondary emissions changes for each rule.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS in 2015[1]

	Final[4]
Total Monetized Benefits[2]	N/A
Total Costs[3]	-$15 million
Net Benefits	N/A
Non-monetized Benefits	11,000 tons of HAP[5]
	190,000 tons of VOC
	1.0 million tons of methane
	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment
	Vegetation effects
	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; 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. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons**.**

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAP and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NESHAP Amendments in 2015[1]

	Final
Total Monetized Benefits[2]	N/A
Total Costs[3]	\$3.5
Net Benefits	N/A
Non-monetized Benefits[5]	670 tons of HAP 1,200 tons of VOC[4] 420 tons of methane[4] Health effects of HAP exposure Health effects of $PM_{2.5}$ and ozone exposure[4] Visibility impairment[4] Vegetation effects[4] Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; 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.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

[5]The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 8,000 metric tons.

Table 6-3 Summary of Emissions Changes for the Final Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS	NESHAP
Change in Direct Emissions	VOC	-190,000	-670
	Methane	-1,000,000	-1,200
	HAP	-11,000	-420
Change in Secondary Emissions (Producer-Side) [1]	CO_2	1,100,000	N/A
	NOx	550	N/A
	PM	19	N/A
	CO	3,000	N/A
	THC	1,100	N/A
Change in Secondary Emissions (Consumer-Side)	CO_2-e	720,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e (short tons)	-19,000,000	-8,800
	CO_2-e (metric tons)	-18,000,000	-8,000

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP Amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Final NSPS and NESHAP Amendments

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS and NESHAP Amendments 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 final rules might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with the NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

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 results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the final rules shows that about 92 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing REC on new and existing wells that are completed after being hydraulically fractured. 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 REC is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

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 2035. 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.doe.gov/oiaf/aeo/overview/index.html>.

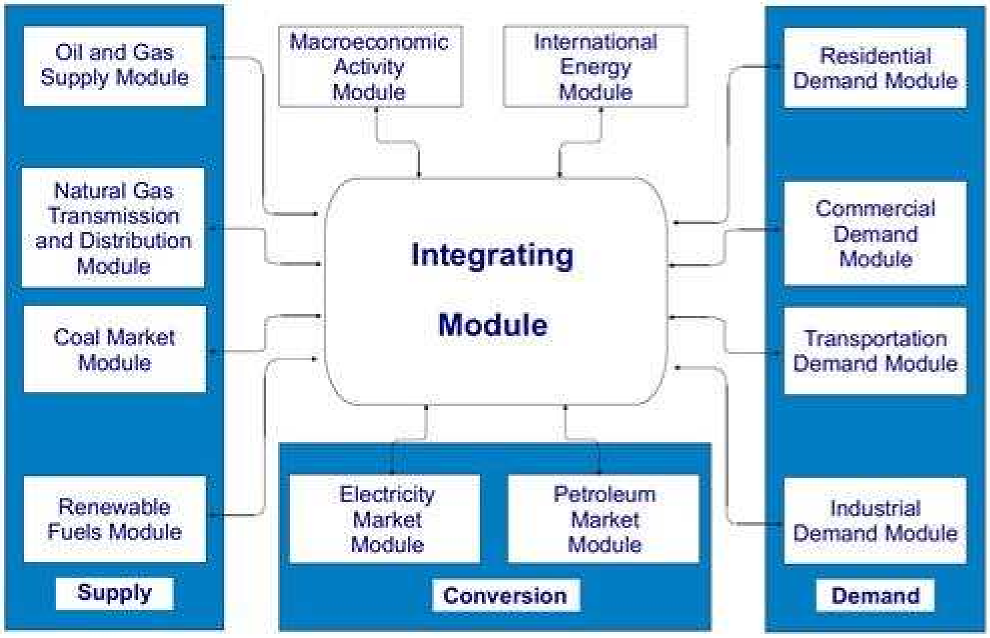

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

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 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[70] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[70] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the final rules, 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, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the final rules. We are able to target additional expenditures for environmental controls required by the NSPS and NESHAP Amendments on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. 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 final rules. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum 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 and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) 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—REC, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the NSPS. 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 which emissions reductions 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 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-4) 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.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in one hundred new wells drilled after the implementation the NSPS are recompleted using hydraulic fracturing in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$)	Wells Applied To in NEMS
Equipment Leaks			
Processing Plants (NSPS)	Subpart VVa	$14	Natural Gas
Reciprocating Compressors			
Gathering and Boosting Stns. (NSPS)	AMM	$10	Natural Gas
Processing Plants (NSPS)	AMM	-$27	Natural Gas
Centrifugal Compressors			
Processing Plants (NSPS)	Route to control	-$35	Natural Gas
Pneumatic Controllers -			
Oil and Gas Production (NSPS)	Emission limits	$11/-$698	Oil/Natural Gas
Processing Plants (NSPS)	Emission limits	7.0	Natural Gas
Storage Vessels			
Emissions at least 6 tons per year (NSPS)	Emission limits	$203/$197	Oil/Natural Gas
Small Glycol Dehydrators			
Production and Transmission Segments (NESHAP)	Emission limits	$60/$60	Oil/Natural Gas
Reporting and Recordkeeping			
NSPS and NESHAP	N/A	$87/$60	Oil/Natural Gas

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion Costs (2008$)	Wells Applied To in NEMS
Well Completions			
Hydraulically Fractured New Natural Gas Wells	REC/Combustion	-$271	New Tight Sand/ Shale Gas/CBM
Well Recompletions			
Hydraulically Refractured Existing Natural Gas Wells	REC/Combustion	-$604	Existing Tight Sand/ Shale Gas /Coalbed Methane

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling 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 final NSPS.

We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells. For the final NSPS, we estimate that natural gas recovery is 2,473 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that this per-well natural gas recovery estimate is lower than the per-well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, REC that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells differently in that we estimated the natural gas recovery by natural gas resource type based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells to be about 3.4 bcf, with 1.6 bcf accruing to shale gas, 1.4 bcf accruing to tight sands, and 0.4 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, 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, as well as whether and to what extent the final NSPS and NESHAP Amendments might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and predicted results for 2015 under the final rules. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the final rules are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Successful Wells Drilled			
Natural Gas	16,373	19,097	19,162
Crude Oil	10,352	11,025	11,025
Total	**26,725**	**30,122**	**30,164**
% Change in Successful Wells Drilled from Baseline			
Natural Gas			0.34%
Crude Oil			0.00%
Total			**0.22%**

We estimate that the number of successful natural gas wells drilled increases slightly for the final NSPS, while the number of successful crude oil wells drilled does not change. The number of successful natural gas wells drilled is estimated to increase about 0.34%. Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the NSPS, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The number of successful wells drilled increase in tight sands, shale gas, as well as coalbed methane.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Successful Wells Drilled			
Conventional Gas Wells	7,267	7,607	7,607
Tight Sands	2,441	2,772	2,785
Shale Gas	5,007	7,022	7,066
Coalbed Methane	1,593	1,609	1,618
Total	**16,308**	**19,010**	**19,076**
% Change in Successful Wells Drilled from Baseline			
Conventional Gas Wells			0.00%
Tight Sands			0.47%
Shale Gas			0.63%
Coalbed Methane			0.56%
Total			**0.35%**

Well drilling in tight sands is estimated to increase slightly, about 0.47 percent. Drilling in shale gas is forecast to increase from the baseline by 0.63 percent. Wells in CBM reserves are also estimated to increase from the baseline by 0.56 percent.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the final NSPS and NESHAP Amendments, as of 2015. Domestic natural gas and crude oil production are not forecast to change under the final rules, again because impacts of the rules are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Domestic Production			
Natural Gas (trillion cubic feet)	21.05	22.43	22.43
Crude Oil (million barrels/day)	5.46	5.81	5.81
Natural Gas			0.00%
Crude Oil			0.00%

The NEMS analysis estimates no increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the NSPS (approximately 43 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new post-rule equilibrium, producers implementing emissions controls still capture and sell approximately 43 bcf of natural gas. For example, as shown in Table 7-4, about 11,400 new unconventional natural gas wells are completed under the final NSPS; using assumptions from the engineering cost analysis about voluntary RECs performed, RECs required under State regulations and exploratory wells and relatively low pressure wells exempted from REC requirements, about 4,100 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis, not including the recompletions of existing wells. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, the natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction, according to these results.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. With the exception of tight sands, production from all types of wells is estimated to increase under the final rules. However, the decrease in production from tight sands is estimated to offset the slight production increases estimated in conventional, shale, and coalbed methane formations.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Natural Gas Production by Well Type (trillion cubic feet)			
Conventional Gas Wells	4.06	3.74	3.75
Tight Sands	5.96	5.89	5.85
Shale Gas	5.21	7.20	7.24
Coalbed Methane	1.72	1.67	1.68
Total	**16.95**	**18.51**	**18.51**
% Change in Natural Gas Production by Well Type from Baseline			
Conventional Gas Wells			0.27%
Tight Sands			-0.68%
Shale Gas			0.56%
Coalbed Methane			0.60%
Total			**0.05%**

Note: Totals may not sum due to independent rounding.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. Wellhead natural gas price are not forecast to change under the final rules, while crude oil prices are forecast to decrease slightly under the NSPS.

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Lower 48 Average Wellhead Price			
Natural Gas (2008$ per Mcf)	4.07	4.22	4.22
Crude Oil (2008$ per barrel)	83.65	94.60	94.59
% Change in Lower 48 Average Wellhead Price from Baseline			
Natural Gas			0.00%
Crude Oil			-0.01%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. Commercial and industrial sector consumers of natural gas are estimated to receive slight price increases, while the national average price to consumers of natural gas is not estimated to change.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Delivered Prices (2008$ per million BTU)			
Residential	10.52	10.35	10.35
Commercial	9.26	8.56	8.57
Industrial	4.97	5.07	5.08
Electric Power	4.81	4.77	4.77
Transportation	12.30	12.24	12.24
Average	**6.76**	**6.59**	**6.59**
% Change in Delivered Prices from Baseline			
Residential			0.00%
Commercial			0.12%
Industrial			0.20%
Electric Power			0.00%
Transportation			0.00%
Average			**0.00%**

Final consumption of natural gas is not estimated to change in 2015 from the baseline under the final rules, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Consumption (trillion cubic feet)			
Residential	4.76	4.81	4.81
Commercial	3.22	3.38	3.38
Industrial	6.95	8.05	8.06
Electric Power	7.00	6.98	6.97
Transportation	0.03	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65
Lease and Plant Fuel	1.27	1.20	1.20
Total	**23.86**	**25.11**	**25.11**
% Change in Consumption from Baseline			
Residential			0.00%
Commercial			0.00%
Industrial			0.12%
Electric Power			-0.14%
Transportation			0.00%
Pipeline Fuel			0.00%
Lease and Plant Fuel			0.00%
Total			**0.00%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling estimates that the impacts from the NSPS and NEHSAP Amendments are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil imports do not vary from the baseline in 2015 under the NSPS.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Net Imports			
Natural Gas (trillion cubic feet)	2.75	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70
% Change in Net Imports			
Natural Gas			0.00%
Crude Oil			0.00%

Meanwhile, net imports of natural gas are estimated to decrease about 10 bcf (0.37 percent) under the NSPS, as the increased production substitutes for imported natural gas.

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. The NSPS is estimated to have small effects at the national level. We estimate an increase in 0.01 quadrillion BTU in 2015, a 0.01 percent increase. The percent contribution of natural gas, coal, and biomass is projected to increase slightly in 2015.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Consumption (quadrillion BTU)			
Liquid Fuels	37.41	39.10	39.10
Natural Gas	24.49	25.77	25.78
Coal	20.42	19.73	19.74
Nuclear Power	8.40	8.77	8.77
Hydropower	2.58	2.92	2.92
Biomass	2.98	3.27	3.28
Other Renewable Energy	1.72	2.14	2.14
Other	0.30	0.31	0.31
Total	**98.29**	**102.02**	**102.03**
% Change in Consumption from Baseline			
Liquid Fuels			0.00%
Natural Gas			0.04%
Coal			0.05%
Nuclear Power			0.00%
Hydropower			0.00%
Biomass			0.31%
Other Renewable Energy			0.00%
Other			0.00%
Total			**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the NSPS in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related “consumer-side” GHG emissions. We use the terms “consumer-side” emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels “producer-side” emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)			
Petroleum	2,359.59	2,433.60	2,433.53
Natural Gas	1,283.78	1,352.20	1,352.24
Coal	1,946.02	1,882.08	1,882.76
Other	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,680.52**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline			
Petroleum			0.00%
Natural Gas			0.00%
Coal			0.04%
Other			0.00%
Total			**0.01%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS. Totals may not sum due to independent rounding.

As is shown in Table 7-12, the final rules are predicted to slightly increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 650,000 metric tons (0.01 percent), mainly because consumer-side emissions from coal combustion increase slightly as a result of the slight consumption increases noted in Table 7-11.

7.3 Employment Impact Analysis

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 of sustained high unemployment. 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" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the regulations using labor requirements for the installation, operation, and maintenance of control requirements, as well as reporting and recordkeeping requirements.

Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[71] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

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. Morgenstern et al. (2002) examined how regulated industries respond to regulation. Morgenstern et al. identified three separate components of the employment change in response to a regulation:

- Higher production costs raise market prices, higher prices reduce consumption (and production), reducing demand for labor within the regulated industry ("demand effect");

[71] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effect; pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

- As costs go up, plants add more capital and labor. For example, pollution abatement activities require additional labor services to produce the same level of output ("cost effect");
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect").

The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

Environmental regulations support employment in many basic industries. 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.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the final NSPS will simultaneously increase production of the good output and reduce production of bad outputs. 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 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 excludes these potential adverse effects on the labor market.

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 U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in 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.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the final NSPS and in Table 7-14 for the final NESHAP Amendments. The tables breaks 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. For both the final NSPS and NESHAP Amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 50 FTEs for the final NSPS and about 4 FTEs for the final NESHAP Amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 570 FTEs for the final NSPS and about 30 FTEs for the final NESHAP Amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation.

Two main categories contain the majority of the labor requirements for the final rules: implementing reduced emissions completions (REC) and reporting and recordkeeping requirements for the final NSPS. Also, note that pneumatic controllers have no up-front 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. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 500 FTE, about 87 percent of the total continuing labor requirements for the final NSPS.[72] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions. While individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

[72] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the finalized Mercury and Air Toxics Standards, promulgated on December 16, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Using plant-level Census information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures did not necessarily cause economically significant employment changes in those industries at that time.

For this version of the RIA for the final NSPS and NESHAP Amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and the final rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the final NSPS and NESHAP Amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, NSPS, 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions and Recompletions								
New Hydraulically Fractured Gas Wells	REC/Combustion	4,107	0	218	0	893,397	0	430
New Hydraulically Fractured Gas Wells	Combustion	1,377	0	22	0	29,719	0	14
Hydraulically Re-fractured Gas Wells	REC/Combustion	532	0	218	0	115,721	0	56
Hydraulically Re-fractured Gas Wells	Combustion	121	0	22	0	2,611	0	1
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8	12
Reciprocating Compressors								
Gathering and Boosting Stations	Annual Monitoring/ Maintenance (AMM)	210	1	1	210	210	< 1	< 1
Processing Plants	AMM	209	1	1	209	209	< 1	< 1
Centrifugal Compressors								
Processing Plants	Route to Control	13	355	0	4,615	0	2	0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0	0
Storage Vessels								
Emissions at least 6 tons per year	95% control	304	271	190	82,279	57,582	40	28
Reporting and Recordkeeping for Complete NSPS		All	N/A	N/A	0	68,882	0.0	33
TOTAL		**N/A**	**N/A**	**N/A**	**104,336**	**1,194,055**	**50**	**574**

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 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Final NESHAP Amendments, 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	74	27	285	2,000	21,120	1	10
Transmission	Combustion devices, recovery devices, process modifications	7	27	285	189	1,998	<1	1
Reporting and Recordkeeping for Complete NESHAP Amendments		N/A	N/A	N/A	6,442	38,923	3	19
TOTAL		**81**	**N/A**	**N/A**	**8,631**	**62,040**	**4**	**30**

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

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the final NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the final regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas industry (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the final NSPS and because the segments of the oil and natural gas industry affected by the rules are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the final oil and natural gas NESHAP Amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the final NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) 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 governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the final rules on small entities for both the NESHAP Amendments and NSPS, the analysis indicates that these rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the final NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options as a result of the final NSPS. However, not all components of the final NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. Unlike the controls for the final NSPS, the controls evaluated under the final NESHAP Amendments do not recover significant quantities of natural gas products.

This small entity impacts analysis uses the primary baseline used for the impacts analysis of our NSPS. This primary baseline takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To estimate emissions reductions and compliance costs arising from these voluntary RECs, EPA used information reported to EPA by partners of the EPA Natural Gas STAR. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket[73], as well as in Section 3 of this RIA.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and

[73] "Voluntary Reductions from Gas Well Completions with Hydraulic Fracturing" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[74] Statistics include the total number of establishments and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishmen*t: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA analyses, and the terms are used interchangeably.

[74] See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	Owned by Firms with: < 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the final rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the final rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should focus on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in the oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (IHS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation’s low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The final Oil and Natural Gas NSPS and NESHAP Amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The final rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the final NSPS and NESHAP Amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP Amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP Amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacted by the rules. The approaches taken for the NSPS and NESHAP Amendments differed; more detail on approaches for each set of rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the “sales test.” The “sales test” is the impact methodology EPA employs in analyzing small entity impacts as opposed to a “profits test,” in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a “sales test” for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[75] and is consistent with guidance published by the U.S. SBA’s Office of Advocacy that suggests that cost as a percentage

[75] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[76]

7.4.3 Small Entity Economic Impact Analysis, Final NSPS

7.4.3.1 Overview of Sample Data and Methods

The final NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150)[77] as described in the Industry Profile in Section 2. Although the proportion of small firms in the OGJ 150 is smaller than the proportion evaluated by the Census Bureau's SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. The Census SUSB provides aggregated totals for all businesses in a particular NAICS code. It is not possible to use these data to identify those firms that actually drill wells or specific financial information for individual firms.

The OGJ 150 includes all public firms incorporated in the U.S. with reserves in the U.S. While the OGJ 150 lists only public firms, we believe the list is reasonably representative of the

[76]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

[77] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010 and Oil and Gas Journal. "OGJ150." September 21, 2009.

larger population of public and private firms operating in this segment of the industry. The sample of firms represented by the OGJ 150 accounts for 62% of the gas wells drilled in 2008 and 2009. While the population of firms responsible for the remaining 38% of gas wells may include some small private firms, there are also a number of large private companies and foreign firms not represented in the OGJ 150. Examples of companies that are not included in the OGJ 150, but that are likely responsible for a large number of hydraulically fractured natural gas well completions include BP, Encana, and Royal Dutch Shell.

To further examine the representativeness of the sample, EPA compared the revenues reported for the OGJ 150 to those reported for small firms in the Census Bureau's SUSB. While the average revenues in the OGJ 150 appear significantly larger than those in the Census Bureau's SUSB, this comparison is misleading. First, the OGJ 150 reports pre-tax revenues, which we would expect to be higher in every instance than the post-tax Census Bureau's SUSB receipts.[78] Additionally, due to the size of the sample, the descriptive statistics for the OGJ 150 may be influenced by a few particularly large data points. For example, for firms with 10 to 19 employees, removing one firm from the OGJ 150 sample decreases the average revenue for the group by approximately 38 percent. The result is roughly equal to the Census SUSB average for the same group, even before any adjustment for taxes. We believe that, despite these outliers, the data for the OGJ 150 are generally representative of the population in this industry.

While the Census SUSB data includes a greater proportion of very small firms (0-4 employees) than the OGJ 150 sample, we believe this sample appropriately reflects the industry for a number of reasons. First, the OGJ 150 includes companies of a range of sizes, from 1 to over 1 million employees. While there is generally a relationship between size and revenues, this does not necessarily hold true when examining the impacts on individual firms. In some cases, a firm with relatively few employees may have higher revenues than a much larger firm. Additionally, there is not necessarily a relationship between the size of a firm and the proportion of its costs to revenues. Finally, as discussed above, it is impossible to determine what portion of

[78] Census SUSB receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts excludes all revenue collected for local, state, and federal taxes. http://www.census.gov//econ/susb/definitions.html

the firms in the Census SUSB would be affected firms under the NSPS provisions related to completions of hydraulically fractured and refractured natural gas wells.

In the analysis that follows, we present median, minimum, and maximum values in addition to the average to provide readers with a more complete understanding of the firms in the sample. We are not able to compare these additional statistics to the Census Bureau's SUSB due to the aggregated nature of those data. When making a SISNOSE determination, we calculate the sales test ratio at the firm level, rather than as an average as is reported by the Census SUSB. By using this methodology, we ensure that the results reflect the impacts to all firms in the sample and are not skewed by unusually large data points.

We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

To identify firms that process natural gas, 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 the most recent list of U.S. gas processing facilities[79] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey 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.[80] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies. These firms represent all potentially impacted firms in these segments, not a sample.

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[79] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.

[80] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the final NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 127 (46 percent) of these firms are small according to SBA criteria. We estimate 119 firms (43 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 28 firms (10 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 246 firms for which we have sufficient data that would be potentially affected by the final NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	77	18,451.9	239.6	76.3	0.1	1,116.9
Large	47	1,345,292.0	28623.2	1,788.3	12.9	310,586.0
Subtotal	124	1,363,743.9	10,997.9	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**127**	**24,118.5**	**189.9**	**34.9**	**0.1**	**1,459.1**
Large	**119**	**1,864,342.8**	**16,071.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**246**	**1,888,461.3**	**7,771.4**	**164.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *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. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (117 of the 124 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	74	13,262.9	179.2	60.4	0.1	2,401.9
Large	43	127,505.6	2,965.2	982.7	0.1	22,518.7
Total	**117**	**140,768.5**	**1,203.1**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 117 firms were approximately $140 billion in 2008 dollars). About 9 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 6 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	77	2,049.5	26.6	5.7	0.2	259.3
	Large	44	9,723.1	221.0	153.2	0.6	868.3
	Subtotal	121	11,772.5	97.3	28.3	0.2	868.3
Crude Oil							
	Small	77	1179.6	15.3	3.3	0.1	149.2
	Large	44	5596.3	127.2	88.1	0.4	499.7
	Subtotal	121	6,775.9	56.0	16.3	0.1	499.7
Total							
	Small	**77**	**3,229.1**	**41.9**	**9.0**	**0.3**	**408.5**
	Large	**44**	**15,319.4**	**348.2**	**241.3**	**1.0**	**1,368.0**
	Total	**121**	**18,548.4**	**153.3**	**44.6**	**0.3**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is approximately 6 natural gas wells compared to 153 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as REC.

Unlike the analysis of regulatory impacts on small entities from the NESHAP Amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimated compliance costs in NEMS on a per-well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the final NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some controls.

This estimation procedure yielded an estimate of crude oil well compliance costs of $260 per drilled well and natural gas well compliance costs of $8,800 or less than 1 percent of the average costs of drilling a well according to EIA (see Table 2-8) without considering estimated revenues from product recovery and $260 and -$940 per drilled crude oil and natural gas well, respectively, with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the final NSPS requirements are primary directed toward natural gas wells. Also note that the per-well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates by the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $5.0 million with estimated revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $14/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $6.0 million without estimated revenues from product recovery and $5.9 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Final NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $117 million in 2008 dollars, about 69 percent of the estimated annualized costs of the final NSPS without including revenues from additional product recovery of $116 million. When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample are about $1.1 million.

Table 7-21 presents the distribution of estimated final NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 92 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explained by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 16 percent of the total estimated engineering compliance costs (and about 16 percent of the costs accruing to the integrated and production segment) are concentrated on small firms.

Table 7-21 Distribution of Estimated Final NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

Firm Type/Size	Number of Firms	Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
		Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	77	17,795,916	231,116	48,134	749	2,299,042
Large	47	90,671,503	1,929,181	1,361,483	10,325	7,710,293
Subtotal	124	108,467,419	874,737	221,017	749	7,710,293
Pipeline						
Small	11	3,738	340	123	20	1,264
Large	36	1,641,771	45,605	4,218	41	994,491
Subtotal	47	1,645,509	35,011	2,498	20	994,491
Processing						
Small	39	482,232	12,365	1,906	191	279,864
Large	23	870,458	37,846	8,236	38	429,043
Subtotal	62	1,352,690	21,818	2,764	38	429,043
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	5,828,374	448,336	159,519	2,040	2,892,799
Subtotal	13	5,828,374	448,336	159,519	2,040	2,892,799
Total						
Small	**127**	**18,281,886**	**143,952**	**13,602**	**20**	**2,299,042**
Large	**119**	**99,012,106**	**832,035**	**48,054**	**38**	**7,710,293**
Total	**246**	**117,293,992**	**476,805**	**22,225**	**20**	**7,710,293**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). A total savings from the final NSPS of about $1.1 million is expected to accrue to small firms (about 23 percent of the savings to the integrated and production segment accrue to small firms), while large firms are expected to have a total cost of $2.3 million. Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the final NSPS.

Table 7-22 Distribution of Estimated Final NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

Firm Type/Size	Number of Firms	Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
		Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	77	-1,500,434	-19,486	25	-218,672	23,982
Large	47	-5,137,073	-109,299	-108,363	-721,121	924,574
Subtotal	124	-6,637,507	-53,528	-11,873	-721,121	924,574
Pipeline						
Small	11	3,629	330	119	19	1,226
Large	36	1,593,661	44,268	4,095	40	965,348
Subtotal	47	1,597,289	33,985	2,425	19	965,348
Processing						
Small	39	349,635	8,965	1,382	138	202,911
Large	23	631,112	27,440	5,971	28	311,071
Subtotal	62	980,747	15,819	2,004	28	311,071
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	5,198,212	399,862	143,446	1,511	2,777,165
Subtotal	13	5,198,212	399,862	143,446	1,511	2,777,165
Total						
Small	**127**	**-1,147,170**	**-9,033**	**207**	**-218,672**	**202,911**
Large	**119**	**2,285,911**	**19,209**	**2,419**	**-721,121**	**2,777,165**
Total	**246**	**1,138,741**	**4,629**	**343**	**-721,121**	**2,777,165**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Final NSPS

Firm Type/Size	Number of Firms	Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
		Average	Median	Minimum	Maximum
Production and Integrated					
Small	77	0.49%	0.11%	0.00%	11.86%
Large	47	0.10%	0.07%	0.00%	0.65%
Subtotal	124	0.34%	0.09%	0.00%	11.86%
Pipeline					
Small	11	0.01%	0.00%	0.00%	0.01%
Large	36	0.01%	0.00%	0.00%	0.06%
Subtotal	47	0.01%	0.00%	0.00%	0.06%
Processing					
Small	39	0.02%	0.01%	0.00%	0.16%
Large	23	0.01%	0.00%	0.00%	0.16%
Subtotal	62	0.02%	0.01%	0.00%	0.16%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	0.00%	0.00%	0.00%	0.01%
Subtotal	13	0.00%	0.00%	0.00%	0.01%
Total					
Small	**127**	**0.30%**	**0.04%**	**0.00%**	**11.86%**
Large	**119**	**0.05%**	**0.01%**	**0.00%**	**0.65%**
Total	**246**	**0.18%**	**0.02%**	**0.00%**	**11.86%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.18 percent, with a median ratio of 0.02 percent, a minimum of less than 0.01 percent, and a maximum of over 11 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 0.30 percent and 0.04 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 11 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than on large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Final NSPS

Firm Type/Size	Number of Firms	Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
		Average	Median	Minimum	Maximum
Production and Integrated					
Small	77	-0.01%	0.00%	-0.85%	0.40%
Large	47	0.00%	0.00%	-0.06%	0.14%
Subtotal	124	-0.01%	0.00%	-0.85%	0.40%
Pipeline					
Small	11	0.01%	0.00%	0.00%	0.01%
Large	36	0.01%	0.00%	0.00%	0.06%
Subtotal	47	0.01%	0.00%	0.00%	0.06%
Processing					
Small	39	0.01%	0.01%	0.00%	0.11%
Large	23	0.01%	0.00%	0.00%	0.11%
Subtotal	62	0.01%	0.00%	0.00%	0.11%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	0.00%	0.00%	0.00%	0.01%
Subtotal	13	0.00%	0.00%	0.00%	0.01%
Total					
Small	**127**	**0.00%**	**0.00%**	**-0.85%**	**0.40%**
Large	**119**	**0.00%**	**0.00%**	**-0.06%**	**0.14%**
Total	**246**	**0.00%**	**0.00%**	**-0.85%**	**0.40%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is less than 0.01 percent, with a median ratio of less than 0.01 percent, a minimum of -0.85 percent, and a maximum of 0.40 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are less than 0.01 percent and less than 0.01 percent, respectively, with a minimum of -0.85 percent and a maximum of 0.40 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all of the 127 firms (100 percent) have estimated cost-sales ratios less than 1 percent. The highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Final NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	123	96.9%	127	100.0%
C/S Ratio 1-3%	1	0.8%	0	0.0%
CS Ratio greater than 3%	3	2.4%	0	0.0%

When the estimated revenues from product recovery are not included in the analysis, one firm (less than 1 percent) is estimated to have sales test ratios between 1 and 3 percent. Three firms (less than 3 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of REC for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the final NSPS.

7.4.3.3 Small Entity Impact Analysis, Final NSPS, Additional Qualitative Discussion

7.4.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the final NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, and whether small entities pursue particular “niche” strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid. According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement a REC, a service provider is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are typically automatically read daily, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, is that the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC. To the extent there is a lag between a REC expenditures and receipt of revenue from recovered products, we believe the impact on cash flows would be minimal.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts that help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment, meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

There are situations in which operators, large or small, may face constraints in directing captured gas to the gathering lines or pipelines. In these instances, this rule provides the flexibility to combust completion emissions rather than performing a REC.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the final NSPS.

7.4.3.3.2 Age of Equipment and Final Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the requirements of these rules might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require about $15 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully, offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older equipment. Meanwhile, the REC and emissions combustion requirements in the final NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells that are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $320 million in annualized costs) and expected revenues from natural gas product recovery (about $330 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.4 Small Entity Economic Impact Analysis, Final NESHAP Amendments

The Final NESHAP Amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP Amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to sales ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners of all but 9 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 81 facilities to be affected, and these facilities are owned by an estimated 42 firms. We were unable to obtain financial information on 7 (16 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 35 firms for which we have financial information, we identified 11 small firms (31 percent) and 24 large firms (69 percent) that would be affected by the NESHAP Amendments. Annual compliance costs for small firms are estimated at $390,000 (22 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $1.1 million (66 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $200,000 (11percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 11 small firms identified in the dataset is $35,000, while the mean annual revenue figure for the same firms is over $116 million, or less than 0.01 percent on average for all 10 firms (Table 7-26). The median sale-test ratio for these firms is smaller at 0.09 percent. Large firms are likely to see an average of $48,000 in annual compliance costs, whereas average revenue for these firms exceeds $29 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is less than 0.01 percent, and the median sales-test ratio is also less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Final NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	11	31%	0.24%	0.09%	< 0.01%	0.93%
Large	24	69%	< 0.01%	< 0.01%	< 0.01%	0.01%
All	35	100%	0.08%	< 0.01%	< 0.01%	0.93%

Among the small firms, all are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues (Table 7-27). These firms represent a very small slice of the oil and gas industry in its entirety, less than 0.02 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Final NESHAP Amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	11	100.0%	0.17%
C/S Ratio 1-3%	0	0.0%	0.0%
CS Ratio greater than 3%	0	0.0%	0.0%

7.4.5 Conclusions for NSPS and NESHAP Amendments

While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP Amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues (Table 7-28).

Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, all 136 small firms (100 percent) are likely to have impacts of less than 1 percent.

Table 7-28 Affected Small Firms as a Percent of Small Firms Nationwide, Final NSPS and NESHAP Amendments

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	132	97.1%	136	100.0%
C/S Ratio 1-3%	1	0.7%	0	0.0%
CS Ratio greater than 3%	3	2.2%	0	0.0%

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.5 References

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